FEDERAL REGISTER

Vol. 80 Friday,
No. 205 October 23, 2015

Book 1 of 2 Books

Pages 64305–64660

OFFICE OF THE FEDERAL REGISTER

The **FEDERAL REGISTER** (ISSN 0097–6326) is published daily, Monday through Friday, except official holidays, by the Office of the Federal Register, National Archives and Records Administration, Washington, DC 20408, under the Federal Register Act (44 U.S.C. Ch. 15) and the regulations of the Administrative Committee of the Federal Register (1 CFR Ch. I). The Superintendent of Documents, U.S. Government Publishing Office, Washington, DC 20402 is the exclusive distributor of the official edition. Periodicals postage is paid at Washington, DC.

The **FEDERAL REGISTER** provides a uniform system for making available to the public regulations and legal notices issued by Federal agencies. These include Presidential proclamations and Executive Orders, Federal agency documents having general applicability and legal effect, documents required to be published by act of Congress, and other Federal agency documents of public interest.

Documents are on file for public inspection in the Office of the Federal Register the day before they are published, unless the issuing agency requests earlier filing. For a list of documents currently on file for public inspection, see *www.ofr.gov.*

The seal of the National Archives and Records Administration authenticates the Federal Register as the official serial publication established under the Federal Register Act. Under 44 U.S.C. 1507, the contents of the **Federal Register** shall be judicially noticed.

The **Federal Register** is published in paper and on 24x microfiche. It is also available online at no charge at *www.fdsys.gov*, a service of the U.S. Government Publishing Office.

The online edition of the **Federal Register** is issued under the authority of the Administrative Committee of the Federal Register as the official legal equivalent of the paper and microfiche editions (44 U.S.C. 4101 and 1 CFR 5.10). It is updated by 6:00 a.m. each day the **Federal Register** is published and includes both text and graphics from Volume 59, 1 (January 2, 1994) forward. For more information, contact the GPO Customer Contact Center, U.S. Government Publishing Office. Phone 202-512-1800 or 866-512-1800 (toll free). E-mail, *gpocusthelp.com.*

The annual subscription price for the **Federal Register** paper edition is $749 plus postage, or $808, plus postage, for a combined **Federal Register, Federal Register** Index and List of CFR Sections Affected (LSA) subscription; the microfiche edition of the **Federal Register** including the **Federal Register** Index and LSA is $165, plus postage. Six month subscriptions are available for one-half the annual rate. The prevailing postal rates will be applied to orders according to the delivery method requested. The price of a single copy of the daily **Federal Register,** including postage, is based on the number of pages: $11 for an issue containing less than 200 pages; $22 for an issue containing 200 to 400 pages; and $33 for an issue containing more than 400 pages. Single issues of the microfiche edition may be purchased for $3 per copy, including postage. Remit check or money order, made payable to the Superintendent of Documents, or charge to your GPO Deposit Account, VISA, MasterCard, American Express, or Discover. Mail to: U.S. Government Publishing Office—New Orders, P.O. Box 979050, St. Louis, MO 63197-9000; or call toll free 1-866-512-1800, DC area 202-512-1800; or go to the U.S. Government Online Bookstore site, see *bookstore.gpo.gov.*

How To Cite This Publication: Use the volume number and the page number. Example: 80 FR 12345.

Postmaster: Send address changes to the Superintendent of Documents, Federal Register, U.S. Government Publishing Office, Washington, DC 20402, along with the entire mailing label from the last issue received.

SUBSCRIPTIONS AND COPIES

PUBLIC

Subscriptions:	
Paper or fiche	**202–512–1800**
Assistance with public subscriptions	**202–512–1806**
General online information	**202–512–1530; 1–888–293–6498**
Single copies/back copies:	
Paper or fiche	**202–512–1800**
Assistance with public single copies	**1–866–512–1800 (Toll-Free)**

FEDERAL AGENCIES

Subscriptions:	
Assistance with Federal agency subscriptions:	
Email	*FRSubscriptions@nara.gov*
Phone	**202–741–6000**

Printed on recycled paper.

Contents

Federal Register

Vol. 80, No. 205

Friday, October 23, 2015

Separate Parts In This Issue

Reader Aids

Consult the Reader Aids section at the end of this issue for phone numbers, online resources, finding aids, and notice of recently enacted public laws.

To subscribe to the Federal Register Table of Contents LISTSERV electronic mailing list, go to http://listserv.access.gpo.gov and select Online mailing list archives, FEDREGTOC-L, Join or leave the list (or change settings); then follow the instructions.

CFR PARTS AFFECTED IN THIS ISSUE

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

Federal Register
Vol. 80, No. 205
Friday, October 23, 2015

Presidential Documents

Title 3—

The President

Memorandum of October 20, 2015

Delegation of Authority for Drafting and Submission of the International Trade Data System Annual Report to the Congress

Memorandum for the Secretary of Homeland Security

By the authority vested in me as President by the Constitution and the laws of the United States of America, including section 301 of title 3, United States Code, I hereby delegate to you the reporting function conferred upon the President by section 405 of the SAFE Port Act of 2006, Public Law 109–347.

You are authorized and directed to publish this memorandum in the *Federal Register*.

THE WHITE HOUSE,
Washington, October 20, 2015

[FR Doc. 2015–27167
Filed 10–22–15; 8:45 am]
Billing code 4410–10–P

Rules and Regulations

Federal Register
Vol. 80, No. 205
Friday, October 23, 2015

OFFICE OF PERSONNEL MANAGEMENT

5 CFR Part 950

RIN 3206–AM68

Solicitation of Federal Civilian and Uniformed Service Personnel for Contributions to Private Voluntary Organizations

AGENCY: Office of Personnel Management.

ACTION: Final rule; delay of effective date.

SUMMARY: The United States Office of Personnel Management (OPM) is issuing a final rule to change the effective date of previously published Combined Federal Campaign regulations to January 1, 2017.

DATES: The effective date of the regulations published in the **Federal Register** on April 17, 2014 (79 FR 21581) is delayed until January 1, 2017.

Regarding funds contributed to the CFC during the 2016 campaign year, LFCCs and PCFOs will continue to operate, disburse funds, and submit to compliance requirements in accordance with regulations in 5 CFR part 950 as amended at 71 FR 67284, Nov. 20, 2006.

FOR FURTHER INFORMATION CONTACT: Mary Capule by telephone at (202) 606–2564; by FAX at (202) 606–5056; or by email at *cfc@opm.gov.*

SUPPLEMENTARY INFORMATION: The U.S. Office of Personnel Management (OPM) issued a Notice of Proposed Rulemaking on August 17, 2015 to amend 5 CFR part 950 to change the effective date of the new rule from January 1, 2016 to January 1, 2017. During the comment period, OPM received two comments, including one from a Federal agency and one from a Local Federal Coordinating Committee (LFCC). These comments are addressed below.

The Department of Defense expressed its support for the amendment to allow additional time to test new systems before they are deployed. The Greater Arkansas CFC LFCC requested clarification on the process by which a contract will be awarded to a vendor to serve as the Central Campaign Administrator and the method by which the system will be tested.

The revision involves the change of the effective date of the new CFC regulations published in the **Federal Register** on April 17, 2014. The new effective date for the CFC regulations would ensure that the tools need to put these reforms in place—including the pivotal online charity application and donor pledging systems—are thoroughly tested and fully operational before being made available to charities and donors.

On August 17, 2015 (80 FR 49173), OPM published a proposed rule with requests for public comment in the **Federal Register**. The Agency received two comments, neither of which opposed the change of date. It is therefore publishing the proposed rule as final without change.

Regulatory Flexibility Act

I certify that this regulation will not have a significant economic impact on a substantial number of small entities. Charitable organizations applying to the CFC have an existing, independent obligation to comply with the eligibility and public accountability standards contained in current CFC regulations. Streamlining these standards will be less burdensome.

Executive Orders 12866 and 13563, Regulatory Review

This rule has been reviewed by the Office of Management and Budget in accordance with Executive Orders 12866 and 13563.

List of Subjects in 5 CFR Part 950

Administrative practice and procedures, Charitable contributions, Government employees, Military personnel, Nonprofit organizations and Reporting and recordkeeping requirements.

U.S. Office of Personnel Management.

Beth F. Cobert,

Acting Director.

[FR Doc. 2015–27009 Filed 10–22–15; 8:45 am]

BILLING CODE 6325–58–P

DEPARTMENT OF AGRICULTURE

Animal and Plant Health Inspection Service

7 CFR Part 319

[Docket No. APHIS–2014–0086]

RIN 0579–AE07

Importation of Fresh Peppers From Ecuador Into the United States

AGENCY: Animal and Plant Health Inspection Service, USDA.

ACTION: Final rule.

SUMMARY: We are amending the fruits and vegetables regulations to allow the importation of fresh peppers into the United States from Ecuador. As a condition of entry, the fruit will have to be produced in accordance with a systems approach that includes requirements for fruit fly trapping, pre-harvest inspections, production sites, and packinghouse procedures designed to exclude quarantine pests. The fruit will also be required to be imported in commercial consignments and accompanied by a phytosanitary certificate issued by the national plant protection organization of Ecuador stating that the consignment was produced and prepared for export in accordance with the requirements in the systems approach. This action allows for the importation of fresh peppers from Ecuador while continuing to provide protection against the introduction of plant pests into the United States.

DATES: Effective November 23, 2015.

FOR FURTHER INFORMATION CONTACT: Ms. Claudia Ferguson, Senior Regulatory Policy Specialist, Regulatory Coordination and Compliance, PPQ, APHIS, 4700 River Road Unit 133, Riverdale, MD 20737–1236; (301) 851–2352; *Claudia.Ferguson@aphis.usda.gov.*

SUPPLEMENTARY INFORMATION:

Background

Under the regulations in ''Subpart-Fruits and Vegetables'' (7 CFR 319.56–1 through 319.56–73, referred to below as the regulations), the Animal and Plant Health Inspection Service (APHIS) of the U.S. Department of Agriculture prohibits or restricts the importation of fruits and vegetables into the United

States from certain parts of the world to prevent plant pests from being introduced into and spread within the United States.

On April 24, 2015, we published in the **Federal Register** (80 FR 22930–22934, Docket No. APHIS–2014–0086) a proposal[1] to amend the regulations to allow the common bell pepper (*Capsicum annuum* L.), locoto pepper (*Capsicum baccatum* L.), habanero pepper (*Capsicum chinense* Jacq.), tabasco pepper (*Capsicum frutescens* L.), and manzano pepper (*Capsicum pubescens* Ruiz & Pav.) to be imported into the United States under a systems approach. (Hereafter we refer to these species as ''peppers.'') We also prepared a pest risk assessment (PRA) and a risk management document (RMD). The PRA evaluates the risks associated with the importation of fresh peppers from Ecuador into the United States. The RMD relies upon the findings of the PRA to determine the phytosanitary measures necessary to ensure the safe importation into the United States of fresh peppers from Ecuador.

In the proposed rule, we noted that the PRA rated six plant pests as having a high pest risk potential for following the pathway of peppers from Ecuador into the United States: The insects *Anastrepha fraterculus, Ceratitis capitata, Spodoptera litura, Thrips palmi,* and *Tuta absoluta,* and the fungus *Puccinia pampeana.* The PRA rated the insect *Neoleucinodes elegantalis* and the Andean potato mottle virus with a medium pest risk potential.

We determined in the PRA that measures beyond standard port of arrival inspection will mitigate the risks posed by these plant pests and proposed a systems approach that includes requirements for fruit fly trapping, pre-harvest inspections, production sites, and packinghouse procedures designed to exclude quarantine pests. We also proposed that the fruit be imported in commercial consignments only and accompanied by a phytosanitary certificate issued by the national plant protection organization of Ecuador stating that the consignment was produced and prepared for export in accordance with the systems approach.

We solicited comments concerning our proposal for 60 days ending June 23, 2015. We did not receive any comments.

We have made one minor change to this final rule, *i.e.,* we have added tomato leaf miner as another common name associated with the plant pest *Tuta absoluta.*

Therefore, for the reasons given in the proposed rule, we are adopting the proposed rule as a final rule with the change noted.

Executive Order 12866 and Regulatory Flexibility Act

This final rule has been determined to be not significant for the purposes of Executive Order 12866 and, therefore, has not been reviewed by the Office of Management and Budget.

In accordance with the Regulatory Flexibility Act, we have analyzed the potential economic effects of this action on small entities. The analysis is summarized below. Copies of the full analysis are available by contacting the person listed under **FOR FURTHER INFORMATION CONTACT** or on the Regulations.gov Web site (see **ADDRESSES** above for instructions for accessing Regulations.gov).

This rule amends the regulations to allow the importation of fresh peppers from Ecuador into the United States when a systems approach to pest risk mitigation is used to prevent the introduction of quarantine pests. The systems approach will integrate prescribed mitigation measures that cumulatively achieve the appropriate level of phytosanitary protection.

The most recent production data available show that fresh pepper yields in Ecuador have expanded from approximately 12,522 pounds per hectare (pounds/ha) in 1996 to approximately 66,361 pounds/ha in 2006. The total quantity of fresh peppers that were exported from Ecuador in 2006 and 2007 was 96.3 metric tons (MT) and 206.5 MT, respectively. Sea shipping containers that are 40 feet in length hold approximately 20 U.S. MT. Considering the total volume exported from Ecuador during these years, APHIS estimates imports of no more than 10 containers (200 MT) of fresh peppers from Ecuador into the United States annually. This quantity is equivalent to less than 0.02 percent of annual U.S. fresh pepper production. Similarly, the estimated quantity of fresh pepper imports from Ecuador (200 MT annually) is minimal compared to the total quantity of fresh peppers imported by the United States in recent years (800,000 MT annually).

In the United States, the average value of bell pepper production per farm in 2012 was approximately $52,300, and the average value of chili pepper production per farm was approximately $20,700. Both levels are well below the small-entity standard of $750,000. Establishments classified within NAICS 111219, including pepper farms, are considered small by the Small Business Administration (SBA) if annual sales are not more than $750,000. Accordingly, pepper growers are predominantly small entities according to the SBA standard. Under these circumstances, the Administrator of the Animal and Plant Health Inspection Service has determined that this action will not have a significant economic impact on a substantial number of small entities.

Executive Order 12988

This final rule allows fresh pepper fruit to be imported into the United States from Ecuador. State and local laws and regulations regarding fresh pepper fruit imported under this rule will be preempted while the fruit is in foreign commerce. Fresh fruits are generally imported for immediate distribution and sale to the consuming public, and remain in foreign commerce until sold to the ultimate consumer. The question of when foreign commerce ceases in other cases must be addressed on a case-by-case basis. No retroactive effect will be given to this rule, and this rule will not require administrative proceedings before parties may file suit in court challenging this rule.

Paperwork Reduction Act

In accordance with section 3507(d) of the Paperwork Reduction Act of 1995 (44 U.S.C. 3501 *et seq.*), the information collection or recordkeeping requirements included in this final rule, which were filed under 0579–0437, have been submitted for approval to the Office of Management and Budget (OMB). When OMB notifies us of its decision, if approval is denied, we will publish a document in the **Federal Register** providing notice of what action we plan to take.

E-Government Act Compliance

The Animal and Plant Health Inspection Service is committed to compliance 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. For information pertinent to E-Government Act compliance related to this rule, please contact Ms. Kimberly Hardy, APHIS' Information Collection Coordinator, at (301) 851–2727.

Lists of Subjects in 7 CFR Part 319

Coffee, Cotton, Fruits, Imports, Logs, Nursery stock, Plant diseases and pests, Quarantine, Reporting and recordkeeping requirements, Rice, Vegetables.

[1] To view the proposed rule and supporting documents, go to *http://www.regulations.gov/#!docketDetail;D=APHIS-2014-0086.*

Accordingly, we are amending 7 CFR part 319 as follows:

PART 319–FOREIGN QUARANTINE NOTICES

■ 1. The authority citation for part 319 continues to read as follows:

Authority: 7 U.S.C. 450 and 7701–7772, and 7781–7786; 21 U.S.C. 136 and 136a; 7 CFR 2.22, 2.80, and 371.3.

■ 2. Section 319.56–74 is added to read as follows:

§ 319.56–74 Peppers from Ecuador.

Fresh peppers (*Capsicum annum* L., *Capsicum baccatum* L., *Capsicum chinense* Jacq., *Capsicum frutescens* L., and *Capsicum pubescens* Ruiz & Pav.) from Ecuador may be imported into the United States only under the conditions described in this section. These conditions are designed to prevent the introduction of the following quarantine pests: Andean potato mottle virus; *Anastrepha fraterculus* (Wiedemann), South American fruit fly; *Ceratitis capitata* (Wiedemann), Mediterranean fruit fly; *Neoleucinodes elegantalis* (Guenée), a fruit boring moth; *Puccinia pampeana* Speg., a pathogenic fungus that causes pepper and green pepper rust; *Spodoptera litura* (Fabricius), a leaf-eating moth; *Thrips palmi* Karny, an arthropod; and *Tuta absoluta* (Meyrick) Povolny, South American tomato moth, tomato leaf miner.

(a) *General requirements.* The national plant protection organization (NPPO) of Ecuador must provide an operational workplan to APHIS that details activities that the NPPO of Ecuador will, subject to APHIS' approval of the workplan, carry out to meet the requirements of this section. The operational workplan must include and describe the specific requirements as set forth in this section.

(b) *Commercial consignments.* Peppers from Ecuador may be imported in commercial consignments only.

(c) *Production site requirements.* (1) Pepper production sites must consist of pest-exclusionary structures, which must have double self-closing doors and have all other windows, openings, and vents covered with 1.6 mm (or less) screening.

(2) All production sites that participate in the pepper export program must be registered with the NPPO of Ecuador.

(3) The production sites must be inspected prior to each harvest by the NPPO of Ecuador or its approved designee in accordance with the operational workplan. If any quarantine pests are found to be generally infesting or infecting the production site, the NPPO of Ecuador will immediately prohibit that production site from exporting peppers to the United States and notify APHIS of this action. The prohibition will remain in effect until the NPPO of Ecuador and APHIS agree that the pest risk has been mitigated. If a designee conducts the program, the designation must be detailed in the operational workplan. The approved designee can be a contracted entity, a coalition of growers, or the growers themselves.

(4) The registered production sites must conduct trapping for the fruit flies *A. fraterculus* and *C. capitata* at each production site in accordance with the operational workplan.

(5) If a single *A. fraterculus* or *C. capitata* is detected inside a registered production site or in a consignment, the NPPO of Ecuador must immediately prohibit that production site from exporting peppers to the United States and notify APHIS of the action. The prohibition will remain in effect until the NPPO of Ecuador and APHIS agree that the risk has been mitigated.

(6) The NPPO of Ecuador must maintain records of trap placement, checking of traps, and any quarantine pest captures in accordance with the operational workplan. Trapping records must be maintained for APHIS review for at least 1 year.

(7) The NPPO of Ecuador must maintain a quality control program, approved by APHIS, to monitor or audit the trapping program in accordance with the operational workplan.

(d) *Packinghouse procedures.* (1) All packinghouses that participate in the export program must be registered with the NPPO of Ecuador.

(2) The peppers must be packed within 24 hours of harvest in a pest-exclusionary packinghouse. The peppers must be safeguarded by an insect-proof mesh screen or plastic tarpaulin while in transit to the packinghouse and while awaiting packing. The peppers must be packed in insect-proof cartons or containers, or covered with insect-proof mesh or plastic tarpaulin, for transit into the United States. These safeguards must remain intact until arrival in the United States or the consignment will be denied entry into the United States.

(3) During the time the packinghouse is in use for exporting peppers to the United States, the packinghouse may only accept peppers from registered approved production sites.

(e) *Phytosanitary certificate.* Each consignment of peppers must be accompanied by a phytosanitary certificate issued by the NPPO of Ecuador bearing the additional declaration that the consignment was produced and prepared for export in accordance with the requirements of this section. The shipping box must be labeled with the identity of the production site.

(Approved by the Office of Management and Budget under control number 0579–0437)

Done in Washington, DC, this 19th day of October 2015.

Kevin Shea,

Administrator, Animal and Plant Health Inspection Service.

[FR Doc. 2015–27013 Filed 10–22–15; 8:45 a.m.]

BILLING CODE 3410–34–P

DEPARTMENT OF AGRICULTURE

National Institute of Food and Agriculture

7 CFR Part 3430

RIN 0524–AA65

Competitive and Noncompetitive Non-Formula Federal Assistance Programs—Specific Administrative Provisions for the Food Insecurity Nutrition Incentive Grants Program

AGENCY: National Institute of Food and Agriculture, USDA.

ACTION: Final rule.

SUMMARY: The National Institute of Food and Agriculture (NIFA) is publishing a final rule for the Food Insecurity Nutrition Incentive Grants Program. This final rule adds a subpart entitled ''Food Insecurity Nutrition Incentive Grants Program'' to the part entitled ''Competitive and Noncompetitive Non-formula Federal Assistance Programs—General Award Administrative Provisions''.

DATES: This final rule becomes effective on October 23, 2015.

FOR FURTHER INFORMATION CONTACT: Lisa Scott-Morring, Policy Branch Chief, Policy and Oversight Division, Phone: 202–401–4515, Email: *lisa.scott-morring@nifa.usda.gov.*

SUPPLEMENTARY INFORMATION:

I. Background and Summary

Authority

The Food Insecurity Nutrition Incentive Program (FINI) is authorized under section 4405 of the Food, Conservation, and Energy Act of 2008 (7 U.S.C. 7517), as added by section 4208 of the Agricultural Act of 2014 (Pub. L. 113–79).

Organization of 7 CFR Part 3430

A primary function of NIFA is the fair, effective, and efficient administration of Federal assistance programs implementing agricultural research, education, and extension programs. The awards made under the above authority are subject to the NIFA assistance regulations at 7 CFR part 3430, Competitive and Noncompetitive Non-formula Federal Assistance Programs—General Award Administrative Provisions. NIFA's development and publication of this part serve to enhance its accountability and to standardize procedures across the Federal assistance programs it administers while providing transparency to the public. NIFA published 7 CFR part 3430 with subparts A through E as a final rule on September 4, 2009 [74 FR 45736–45752]. These regulations apply to all Federal assistance programs administered by NIFA except for the capacity grant programs identified in 7 CFR 3430.1(f), the Small Business Innovation Research programs, with implementing regulations at 7 CFR part 3403, and the Veterinary Medicine Loan Repayment Program, with implementing regulations at 7 CFR part 3431.

NIFA organized part 3430 as follows: Subparts A through E provide administrative provisions for all competitive and noncompetitive non-capacity Federal assistance programs. Subparts F and thereafter apply to specific NIFA programs.

NIFA is, to the extent practical, using the following subpart template for each program authority: (1) Applicability of regulations; (2) purpose; (3) definitions (those in addition to or different from § 3430.2); (4) eligibility; (5) project types and priorities; (6) funding restrictions; and (7) matching requirements. Subparts F and thereafter contain the above seven components in this order. Additional sections may be added for a specific program if there are additional requirements or a need for additional rules for the program (*e.g.,* additional reporting requirements). Through this rulemaking, NIFA is adding subpart P for the administrative provisions that are specific to the FINI program.

II. Administrative Requirements for the Rulemaking

Executive Order 12866

This action has been determined to be not significant for purposes of Executive Order 12866. The rule will not create a serious inconsistency or otherwise interfere with an action taken or planned by another agency; nor will it materially alter the budgetary impact of entitlements, grants, user fees, or loan programs; nor will it have an annual effect on the economy of $100 million or more; nor will it adversely affect the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or State, local, or Tribal governments or communities in a material way. Further, it does not raise a novel legal or policy issue arising out of legal mandates, the President's priorities, or principles set forth in the Executive Order.

Regulatory Flexibility Act of 1980

This final rule has been reviewed in accordance with the Regulatory Flexibility Act of 1980, as amended by the Small Business Regulatory Enforcement Fairness Act of 1996, (5 U.S.C. 601–612). The Department certifies that this final rule will not have a significant economic impact on a substantial number of small entities. The rule does not involve regulatory and informational requirements regarding businesses, organizations, and governmental jurisdictions subject to regulation.

Paperwork Reduction Act

The Department certifies that this final rule has been assessed in accordance with the requirements of the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.* The Department concludes that this final rule does not impose any new information requirements or increase the burden hours. In addition to the SF–424 form families (*i.e.,* Research and Related and Mandatory) and the SF–425 Federal Financial Report (FFR) No. 0348–0061, NIFA has three currently approved OMB information collections associated with this rulemaking: OMB Information Collection No. 0524–0042, NIFA REEport; No. 0524–0041, NIFA Application Review Process; and No. 0524–0026, Assurance of Compliance with the Department of Agriculture Regulations Assuring Civil Rights Compliance and Organizational Information.

Catalog of Federal Domestic Assistance

This final rule applies to the following Federal financial assistance programs administered by NIFA: CFDA No. 10.331 Food Insecurity Nutrition Incentive Grants Program.

Unfunded Mandates Reform Act of 1995 and Executive Order 13132

The Department has reviewed this final rule in accordance with the requirements of Executive Order No. 13132 and the Unfunded Mandates Reform Act of 1995, 2 U.S.C. 1501 *et seq.,* and has found no potential or 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 there is no Federal mandate contained herein that could result in increased expenditures by State, local, or tribal governments, or by the private sector, the Department has not prepared a budgetary impact statement.

Clarity of This Regulation

Executive Order 12866 and the President's Memorandum of June 1, 1998, require each agency to write all rules in plain language. The Department invites comments on how to make this final rule easier to understand.

List of Subjects in 7 CFR Part 3430

Administrative practice and procedure, Agricultural research, Grant programs—agriculture, Privacy, Reporting and recordkeeping requirements.

Accordingly, 7 CFR part 3430 is amended as set forth below:

PART 3430—COMPETITIVE AND NONCOMPETITIVE NON-FORMULA FEDERAL ASSISTANCE PROGRAMS—GENERAL AWARD ADMINISTRATIVE PROVISIONS

■ 1. The authority citation for part 3430 continues to read as follows:

Authority: 7 U.S.C. 3316; Pub. L. 106–107 (31 U.S.C. 6101 note).

■ 2. Add subpart P to read as follows:

Subpart P—Food Insecurity Nutrition Incentive Program

Subpart P—Food Insecurity Nutrition Incentive Program

§ 3430.1100 Applicability of regulations.

The regulations in this subpart apply to the Food Insecurity Nutrition Incentive (FINI) grants program authorized under section 4405 of the Food, Conservation, and Energy Act of 2008 (7 U.S.C. 7517), as added by section 4208 of the Agricultural Act of 2014 (Pub. L. 113–79).

§ 3430.1101 Purpose.

The primary goal of the FINI grants program is to fund and evaluate projects intended to increase the purchase of fruits and vegetables by low-income consumers participating in Supplemental Nutrition Assistance Program (SNAP) by providing incentives at the point of purchase.

§ 3430.1102 Definitions.

The definitions applicable to the FINI grants program under this subpart include:

Community food assessment means a collaborative and participatory process that systematically examines a broad range of community food issues and assets, so as to inform change actions to make the community more food secure.

Emergency feeding organization means a public or nonprofit organization that administers activities and projects (including the activities and projects of a charitable institution, a food bank, a food pantry, a hunger relief center, a soup kitchen, or a similar public or private nonprofit eligible recipient agency) providing nutrition assistance to relieve situations of emergency and distress through the provision of food to needy persons, including low-income and unemployed persons. (See 7 U.S.C. 7501).

Exemplary practices means high quality community food security work that emphasizes food security, nutritional quality, environmental stewardship, and economic and social equity.

Expert reviewers means individuals selected from among those recognized as uniquely qualified by training and experience in their respective fields to give expert advice on the merit of grant applications in such fields who evaluate eligible proposals submitted to this program in their respective area(s) of expertise.

Food security means access to affordable, nutritious, and culturally appropriate food for all people at all times.

Fruits and vegetables means, for the purposes of the incentives provided under these grants, any variety of fresh, canned, dried, or frozen whole or cut fruits and vegetables without added sugars, fats or oils, and salt (*i.e.* sodium).

Logic model means a systematic and visual way to present and share an understanding of the relationships among resources available to operate a program, and includes: Planned activities and anticipated results; and the presentation of the resources, inputs, activities, outputs, outcomes and impacts.

Outcomes means the changes in the wellbeing of individuals that can be attributed to a particular project, program, or policy, or that a program hopes to achieve over time. They indicate a measurable change in participant knowledge, attitudes, or behaviors.

Process evaluation means examining program activities in terms of:

(1) The age, sex, race, occupation, or other demographic variables of the target population;

(2) The program's organization, funding, and staffing; and

(3) The program's location and timing. Process evaluation focuses on program activities rather than outcomes.

PromiseZone refers to designated high-poverty communities ''where the federal government will partner with and invest in communities to create jobs, leverage private investment, increase economic activity, expand educational opportunities, and improve public safety.'' See *https://www.hudexchange.info/programs/promise-zones/.*

Nonprofit organization means a special type of organizationthat has been organized to meet specific tax-exempt purposes. To qualify for nonprofit status, your organizationmust be formed to benefit:

(1) The public;

(2) A specific group of individuals; or

(3) The membership of the nonprofit.

StrikeForce means the ''USDA's StrikeForce Initiative for Rural Growth and Opportunity, which works to address the unique set of challenges faced by many of America's rural communities. Through StrikeForce, USDA is leveraging resources and collaborating with partners and stakeholders to improve economic opportunity and quality of life in these areas. See *http://www.usda.gov/wps/portal/usda/usdahome?navid=STRIKE_FORCE* for more information.

Supplemental Nutrition Assistance Program (SNAP) means the supplemental nutrition assistance program established under the Food and Nutrition Act of 2008 (7 U.S.C. 2011 *et seq.*).

Value chain means adding value to a product, including production, marketing, and the provision of after-sales service and incorporating fair pricing to farms. It also involves keeping the final pricing to customers within competitive range. Value chain development, therefore, is a process of building relationships between supplier and buyer that are reciprocal and win-win; instead of always striving to buy at lowest cost.

§ 3430.1103 Eligibility.

(a) *In general.* Eligibility to receive a grant under this subpart is limited to government agencies and nonprofit organizations. All applicants must demonstrate in their application that they are a government agency or nonprofit organization. Eligible government agencies and nonprofit organizations may include:

(1) An emergency feeding organization;

(2) An agricultural cooperative;

(3) A producer network or association;

(4) A community health organization;

(5) A public benefit corporation;

(6) An economic development corporation;

(7) A farmers' market;

(8) A community-supported agriculture program;

(9) A buying club;

(10) A SNAP-authorized retailer; and

(11) A State, local, or tribal agency.

(b) *Further eligibility requirements*—(1) *Related to projects.* To be eligible to receive a grant under this subpart, applicants must propose projects that:

(i) Have the support of the State SNAP agency;

(ii) Would increase the purchase of fruits and vegetables by low-income consumers participating in SNAP by providing incentives at the point of purchase;

(iii) Operate through authorized SNAP retailers and comply with all relevant SNAP regulations and operating requirements;

(iv) Agree to participate in the FINI comprehensive program evaluation;

(v) Ensure that the same terms and conditions apply to purchases made by individuals with SNAP benefits and with incentives under the FINI grants program as apply to purchases made by individuals who are not members of households receiving benefits as provided in § 278.2(b) of this title; and

(vi) Include effective and efficient technologies for benefit redemption systems that may be replicated in other States and communities.

(2) *Related to experience and other competencies.* To be eligible to receive a grant under this subpart, applicants must meet the following requirements:

(i) Have experience:

(A) In efforts to reduce food insecurity in the community, including food distribution, improving access to services, or coordinating services and programs; or

(B) With the SNAP program;

(ii) Demonstrate competency to implement a project, provide fiscal accountability, collect data, and prepare reports and other necessary documentation;

(iii) Secure the commitment of the State SNAP agency to cooperate with the project; and

(iv) Possess a demonstrated willingness to share information with researchers, evaluators (including the independent evaluator for the program), practitioners, and other interested parties, including a plan for dissemination of results to stakeholders.

(c) *Other, non-eligibility considerations.* Applicants are encouraged:

(1) To propose projects that will provide employees with important job skills; and

(2) To have experience the following areas:

(i) Community food work, particularly concerning small and medium-size farms, including the provision of food to people in low-income communities and the development of new markets in low-income communities for agricultural producers; and

(ii) Job training and business development activities for food-related activities in low-income communities.

(d) *Partnerships.* Applicants for a grant under this subpart are encouraged to seek and create partnerships with public or private, nonprofit or for-profit entities, including links with academic institutions (including minority-serving colleges and universities) or other appropriate professionals; community-based organizations; local government entities; PromiseZone lead applicant/organization or implementation partners; and StrikeForce area coordinators or partnering entities for the purposes of providing additional Federal resources and strengthening under-resourced communities. Only the applicant must meet the requirements specified in this section for grant eligibility. Project partners and collaborators need not meet the eligibility requirements.

§ 3430.1104 Project types and priorities.

(a) *FINI Pilot Projects (FPP).* FPPs are aimed at new entrants seeking funding for a project in the early stages of incentive program development.

(b) *FINI Projects (FP).* FPs are aimed at mid-sized groups developing incentive programs at the local or State level.

(c) *FINI Large Scale Projects (FLSP).* FLSPs are aimed at groups developing multi-county, State, and regional incentive programs with the largest target audience of all FINI projects.

§ 3430.1105 Funding restrictions.

(a) *Construction.* Funds made available for grants under this subpart shall not be used for the construction of a new building or facility or the acquisition, expansion, remodeling, or alteration of an existing building or facility (including site grading and improvement, and architect fees).

(b) *Indirect costs.* Subject to § 3430.54, indirect costs are allowable.

§ 3430.1106 Matching requirements.

(a) *In general.* Recipients of a grant under this subpart must provide matching contributions on a dollar-for-dollar basis for all Federal funds awarded.

(b) *Source and type.* The non-Federal share of the cost of a project funded by a grant under this subpart may be provided by a State or local government or a private source. The matching requirement in this section may be met through cash or in-kind contributions, including third-party in-kind contributions fairly evaluated, including facilities, equipment, or services.

(c) *Limitation.* If an applicant partners with a for-profit entity, the non-Federal share that is required to be provided by the applicant may not include the services of an employee of that for-profit entity, including salaries paid or expenses covered by that employer.

(d) *Indirect costs.* Use of indirect costs as in-kind matching contributions is subject to § 3430.52(b).

§ 3430.1107 Program requirements.

The term of a grant under this subpart may not exceed 5 years. No-cost extensions of time beyond the maximum award terms will not be considered or granted.

§ 3430.1108 Priorities.

(a) *In general.* Except as provided in paragraph (b) of this section, in awarding grants under this subpart, NIFA will give priority to projects that:

(1) Maximize the share of funds used for direct incentives to participants;

(2) Use direct-to-consumer sales marketing;

(3) Demonstrate a track record of designing and implementing successful nutrition incentive programs that connect low-income consumers and agricultural producers;

(4) Provide locally or regionally produced fruits and vegetables;

(5) Are located in underserved communities; or

(6) Address other criteria as established by NIFA and included in the requests for applications.

(b) *Exception.* The priorities in paragraph (a) of this section that are given by NIFA will depend on the project type identified in § 3430.1104. Applicants should refer to the requests for applications to determine which priorities will be given to which project types.

Done at Washington, DC, this 16th day of October, 2015.

Robert E. Holland,

Associate Director for Operations, National Institute of Food and Agriculture.

[FR Doc. 2015–26848 Filed 10–22–15; 8:45 am]

BILLING CODE 3410–22–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 39

[Docket No. FAA–2012–0913; Directorate Identifier 2012–NE–23–AD; Amendment 39–18261; AD 2015–18–03]

RIN 2120–AA64

Airworthiness Directives; Honeywell International Inc. Turboprop Engines (Type Certificate Previously Held by AlliedSignal Inc., Garrett Engine Division; Garrett Turbine Engine Company; and AiResearch Manufacturing Company of Arizona)

Correction

In rule document 2015–25606, appearing on pages 61091 through 61093 in the issue of Friday, October 9, 2015, make the following correction:

On page 61093, at the top of the page, the image heading ''Figure 2 to Paragraph (e)—Airplane Operating Procedures'' should read ''Figure 1 to Paragraph (e)—Airplane Operating Procedures''.

[FR Doc. C1–2015–25606 Filed 10–22–15; 8:45 am]

BILLING CODE 1505–01–D

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 39

[Docket No. FAA–2015–0869; Directorate Identifier 2015–NE–11–AD; Amendment 39–18296; AD 2015–21–04]

RIN 2120–AA64

Airworthiness Directives; Pratt & Whitney Turbofan Engines

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Final rule.

SUMMARY: We are adopting a new airworthiness directive (AD) for certain Pratt & Whitney (PW) PW4164, PW4168, PW4168A, PW4164–1D, PW4168–1D, PW4168A–1D, and PW4170 turbofan engines. This AD was prompted by crack finds in the 6th stage low-pressure turbine (LPT) disk. This AD requires

removal of the affected 6th stage LPT disks. We are issuing this AD to prevent failure of the 6th stage LPT disk, which could lead to an uncontained disk release, damage to the engine, and damage to the airplane.

DATES: This AD is effective November 27, 2015.

The Director of the Federal Register approved the incorporation by reference of a certain publication listed in this AD as of November 27, 2015.

ADDRESSES: For service information identified in this AD, contact Pratt & Whitney, 400 Main St., East Hartford, CT 06108; phone: 860–565–8770; fax: 860–565–4503. You may view this service information at the FAA, Engine & Propeller Directorate, 12 New England Executive Park, Burlington, MA. For information on the availability of this material at the FAA, call 781–238–7125. It is also available on the Internet at *http://www.regulations.gov* by searching for and locating Docket No. FAA–2015–0869.

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–2015–0869; 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 AD, the regulatory evaluation, any comments received, and other information. The address for the Docket Office (phone: 800–647–5527) is Document Management Facility, U.S. Department of Transportation, Docket Operations, M–30, West Building Ground Floor, Room W12–140, 1200 New Jersey Avenue SE., Washington, DC 20590.

FOR FURTHER INFORMATION CONTACT: Besian Luga, Aerospace Engineer, Engine Certification Office, FAA, Engine & Propeller Directorate, 12 New England Executive Park, Burlington, MA 01803; phone: 781–238–7750; fax: 781–238–7199; email: *besian.luga@faa.gov*.

SUPPLEMENTARY INFORMATION:

Discussion

We issued a notice of proposed rulemaking (NPRM) to amend 14 CFR part 39 by adding an AD that would apply to all PW PW4164, PW4168, PW4168A, PW4164–1D, PW4168–1D, PW4168A–1D, and PW4170 turbofan engines. The NPRM published in the **Federal Register** on June 8, 2015 (80 FR 32316). The NPRM was prompted by findings of cracks in the 6th stage LPT disk. The NPRM proposed to require removal of the affected 6th stage LPT disks. We are issuing this AD to correct the unsafe condition on these products.

Comments

We gave the public the opportunity to participate in developing this AD. The following presents the comment received on the NPRM (80 FR 32316, June 8, 2015) and the FAA's response to this comment.

Request to Clarify Definition of LPT Shop Visit

An individual commenter requested that we define ''LPT shop visit'' more precisely to prevent unnecessary discussions regarding its meaning.

We agree. We revised the definition to read: ''For the purpose of this AD, an ''LPT shop visit'' is defined as the removal of the 6th stage disk from the LPT rotor and the removal of the blades from the disk.''

Conclusion

We reviewed the relevant data, considered the comment received, and determined that air safety and the public interest require adopting this AD with the change described previously.

Related Service Information Under 1 CFR Part 51

We reviewed PW Service Bulletin (SB) No. PW4G–100–72–252, dated November 18, 2014. The SB provides a list of PW 6th stage LPT disks affected by this AD. This service information is reasonably available because the interested parties have access to it through their normal course of business or see **ADDRESSES** for other ways to access this service information.

Costs of Compliance

We estimate that this AD affects 18 engines installed on airplanes of U.S. registry. We also estimate that no additional hours will be required per engine to comply with this AD because the engine is already disassembled in the shop when we require the part to be removed. The average labor rate is $85 per hour. We estimate that 6 engines will require replacement parts during an LPT shop visit, and that the prorated replacement parts cost will be $108,800 per engine. Based on these figures, we estimate the cost of this AD on U.S. operators to be $652,800.

Authority for This Rulemaking

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

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

Regulatory Findings

This AD will not have federalism implications under Executive Order 13132. This AD will not have a substantial direct effect on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government.

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

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

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

(3) Will not affect intrastate aviation in Alaska to the extent that it justifies making a regulatory distinction, and

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

List of Subjects in 14 CFR Part 39

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

Adoption of the Amendment

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

PART 39—AIRWORTHINESS DIRECTIVES

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

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

§ 39.13 [Amended]

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

2015–21–04 Pratt & Whitney: Amendment 39–18296; Docket No. FAA–2015–0869; Directorate Identifier 2015–NE–11–AD.

(a) Effective Date

This AD is effective November 27, 2015.

(b) Affected ADs

None.

(c) Applicability

This AD applies to all Pratt & Whitney (PW) PW4164, PW4168, PW4168A, PW4164–1D, PW4168–1D, PW4168A–1D, and PW4170 turbofan engines with 6th stage low-pressure turbine (LPT) disks, part number 50N886, installed.

(d) Unsafe Condition

This AD was prompted by crack finds in the 6th stage LPT disk. We are issuing this AD to prevent failure of the 6th stage LPT disk, which could lead to an uncontained disk release, damage to the engine, and damage to the airplane.

(e) Compliance

Comply with this AD within the compliance times specified, unless already done. At the next LPT shop visit after the effective date of this AD, remove from service 6th stage LPT disks with serial numbers listed in the Accomplishment Instructions, Table 1, of PW Service Bulletin No. PW4G–100–72–252, dated November 18, 2014.

(f) Definition

For the purpose of this AD, an ''LPT shop visit'' is defined as the removal of the 6th stage disk from the LPT rotor and the removal of the blades from the disk.

(g) Alternative Methods of Compliance (AMOCs)

The Manager, Engine Certification Office, FAA, may approve AMOCs for this AD. Use the procedures found in 14 CFR 39.19 to make your request. You may email your request to: *ANE-AD-AMOC@faa.gov*.

(h) Related Information

For more information about this AD, contact Besian Luga, Aerospace Engineer, Engine Certification Office, FAA, Engine & Propeller Directorate, 12 New England Executive Park, Burlington, MA 01803; phone: 781–238–7750; fax: 781–238–7199; email: *besian.luga@faa.gov*.

(i) Material Incorporated by Reference

(1) The Director of the Federal Register approved the incorporation by reference (IBR) of the service information listed in this paragraph under 5 U.S.C. 552(a) and 1 CFR part 51.

(2) You must use this service information as applicable to do the actions required by this AD, unless the AD specifies otherwise.

(3) The following service information was approved for IBR on November 27, 2015.

(i) Pratt & Whitney (PW) Service Bulletin No. PW4G–100–72–252, dated November 18, 2014.

(ii) Reserved.

(4) For PW service information identified in this AD, contact Pratt & Whitney, 400 Main St., East Hartford, CT 06108; phone: 860–565–8770; fax: 860–565–4503.

(5) You may view this service information at FAA, Engine & Propeller Directorate, 12 New England Executive Park, Burlington, MA. For information on the availability of this material at the FAA, call 781–238–7125.

(6) You may view this service information 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*.

Issued in Burlington, Massachusetts, on October 9, 2015.

Robert G. Mann,

Acting Directorate Manager, Engine & Propeller Directorate, Aircraft Certification Service.

[FR Doc. 2015–26346 Filed 10–22–15; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 39

[Docket No. FAA–2015–1383; Directorate Identifier 2015–NE–15–AD; Amendment 39–18293; AD 2015–21–01]

RIN 2120–AA64

Airworthiness Directives; Technify Motors GmbH Reciprocating Engines

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Final rule.

SUMMARY: We are adopting a new airworthiness directive (AD) for all Technify Motors GmbH TAE 125–02 reciprocating engines with a dual mass flywheel installed. This AD requires installation of a start phase monitoring system and associated specified software. This AD was prompted by reports of a gearbox drive shaft breaking during starting or restarting of the engine. We are issuing this AD to prevent overload and failure of the gearbox drive shaft, which could result in failure of the engine, in-flight shutdown, and loss of control of the airplane.

DATES: This AD becomes effective November 27, 2015.

The Director of the Federal Register approved the incorporation by reference of a certain publication listed in this AD as of November 27, 2015.

ADDRESSES: For service information identified in this AD, contact Technify Motors GmbH, Platanenstrasse 14, D–09356 Sankt Egidien, Germany; phone: +49 37204 696 0; fax: +49 37204 696 29125; email: *info@centurion-engines.com;* and Diamond Aircraft Industries GmbH, N. A. Otto-Strasse 5, 2700 Wiener Neustadt, Austria; phone: +43 2622 26700; fax: +43 2622 26700 1369; email: *airworthiness@diamond-air.at.* You may view this service information at the FAA, Engine & Propeller Directorate, 12 New England Executive Park, Burlington, MA. For information on the availability of this material at the FAA, call 781–238–7125. It is also available on the Internet at *http://www.regulations.gov* by searching for and locating Docket No. FAA–2015–1383.

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–2015–1383; 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 AD, the mandatory continuing airworthiness information (MCAI), the regulatory evaluation, any comments received, and other information. The address for the Docket Office (phone: 800–647–5527) is Document Management Facility, U.S. Department of Transportation, Docket Operations, M–30, West Building Ground Floor, Room W12–140, 1200 New Jersey Avenue SE., Washington, DC 20590.

FOR FURTHER INFORMATION CONTACT: Robert Green, Aerospace Engineer, Engine Certification Office, FAA, Engine & Propeller Directorate, 12 New England Executive Park, Burlington, MA 01803; phone: 781–238–7754; fax: 781–238–7199; email: *robert.green@faa.gov.*

SUPPLEMENTARY INFORMATION:

Discussion

We issued a notice of proposed rulemaking (NPRM) to amend 14 CFR part 39 by adding an AD that would apply to the specified products. The NPRM was published in the **Federal Register** on July 8, 2015 (80 FR 38990). The NPRM proposed to correct an unsafe condition for the specified products. The MCAI states:

> Cases of a broken gearbox drive shaft have been reported on aeroplanes equipped with TAE 125–02 engines that have a Dual Mass Flywheel installed.
>
> Investigations results showed a possible overload of the gearbox drive shaft during starting of the engine or during restarting of the engine in-flight.
>
> This condition, if not corrected, could lead to engine power loss during flight, possibly resulting in loss of control of the aeroplane.

Comments

We gave the public the opportunity to participate in developing this AD. We received no comments on the NPRM (80 FR 38990, July 8, 2015).

Conclusion

We reviewed the available data and determined that air safety and the public interest require adopting this AD as proposed.

Related Service Information Under 1 CFR Part 51

Technify Motors GmbH has issued Service Bulletin No. SB TMG 125–1018 P1, Revision 1, dated February 5, 2015. The service information describes procedures for installing a start phase monitoring system and associated specified software mapping on particular airplane models. 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 final rule.

Other Related Service Information

Technify Motors GmbH has also issued Technify Motors SB No. TM TAE 000–0007, Revision 28, dated February 5, 2015; Technify Motors Installation Manual No. IM–02–02, Issue 4, Revision 2, dated January 30, 2015, with Chapter 02–IM–13–02, section 13.8.16, Revision 1, dated November 28, 2014; Technify Motors SB No. SB TMG 601–1007 P1, Revision 3, dated February 5, 2015; and Technify Motors SB No. SB TMG 651–1004 P1, Revision 2, dated February 5, 2015. Diamond Aircraft Industries GmbH (DAI) has issued DAI Mandatory Service Bulletin (MSB) No. 42–109/1, dated February 4, 2015; and DAI MSB No. 42–007/16, dated February 4, 2015. The service information describes procedures for installing a start phase monitoring system and associated specified software mapping.

Costs of Compliance

We estimate that this AD affects 97 engines installed on airplanes of U.S. registry. We also estimate that it will take about 3 hours per engine to comply with this AD. The average labor rate is $85 per hour. For 13 of the engines, required parts cost about $285 per engine. For 84 of the engines, required parts cost about $206 per engine. Based on these figures, we estimate the cost of this AD on U.S. operators to be $45,744.

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 AD will not have federalism implications under Executive Order 13132. This AD will not have a substantial direct effect on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government.

For the reasons discussed above, I certify this AD:

(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 to the extent that it justifies making a regulatory distinction, and

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

List of Subjects in 14 CFR Part 39

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

Adoption of the Amendment

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

PART 39—AIRWORTHINESS DIRECTIVES

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

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

§ 39.13 [Amended]

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

2015–21–01 Technify Motors GmbH (Type Certificate Previously Held by Thielert Aircraft Engines GmbH): Amendment 39–18293; Docket No. FAA–2015–1383; Directorate Identifier 2015–NE–15–AD.

(a) Effective Date

This AD becomes effective November 27, 2015.

(b) Affected ADs

None.

(c) Applicability

This AD applies to Technify Motors GmbH TAE 125–02–99 (commercial designation CD–135, formerly Centurion 2.0) and TAE 125–02–114 (commercial designation CD–155, formerly Centurion 2.0S) reciprocating engines, with a dual mass flywheel installed.

(d) Reason

This AD was prompted by reports of a gearbox drive shaft breaking during starting or restarting of the engine. We are issuing this AD to prevent overload and failure of the gearbox drive shaft, which could lead to failure of the engine, in-flight shutdown, and loss of control of the airplane.

(e) Actions and Compliance

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

Within 110 flight hours or at the next scheduled inspection after the effective date of this AD, whichever occurs first, install a start phase monitoring system and software mapping. Use Technify Motors Service Bulletin (SB) No. SB TMG 125–1018 P1, Revision 1, dated February 5, 2015, to do the installation.

(f) Installation Prohibition

After the effective date of this AD, do not install onto any airplane any Technify Motors TAE 125–02–99 or TAE 125–02–114 reciprocating engine that is not equipped with a start phase monitoring system and software mapping.

(g) Alternative Methods of Compliance (AMOCs)

The Manager, Engine Certification Office, may approve AMOCs for this AD. Use the procedures found in 14 CFR 39.19 to make your request. You may email your request to: *ANE-AD-AMOC@faa.gov.*

(h) Related Information

(1) For more information about this AD, contact Robert Green, Aerospace Engineer, Engine Certification Office, FAA, Engine & Propeller Directorate, 12 New England Executive Park, Burlington, MA 01803; phone: 781–238–7754; fax: 781–238–7199; email: *robert.green@faa.gov.*

(2) Refer to MCAI European Aviation Safety Agency AD 2015–0055, dated March 31, 2015, for more information. You may examine the MCAI in the AD docket on the Internet at *http://www.regulations.gov/#!documentDetail;D=FAA-2015-1383-0002.*

(3) Technify Motors SB No. TM TAE 000–0007, Revision 28, dated February 5, 2015; Technify Motors Installation Manual No. IM–02–02, Issue 4, Revision 2, dated January 30, 2015, with Chapter 02–IM–13–02, section 13.8.16, Revision 1, dated November 28, 2014; Technify Motors SB No. SB TMG 601–1007 P1, Revision 3, dated February 5, 2015; and Technify Motors SB No. SB TMG 651–1004 P1, Revision 2, dated February 5, 2015,

which are not incorporated by reference in this AD, can be obtained from Technify Motors GmbH, using the contact information in paragraph (i)(3) of this AD.

(4) Diamond Aircraft Industries GmbH (DAI) MSB No. 42–109/1, dated February 4, 2015; and DAI MSB No. 42–007/16, dated February 4, 2015, which are not incorporated by reference in this AD, can be obtained from Diamond Aircraft Industries GmbH, using the contact information in paragraph (h)(5) of this AD.

(5) For DAI service information identified in this AD, contact Diamond Aircraft Industries GmbH, N. A. Otto-Strasse 5, 2700 Wiener Neustadt, Austria; phone: +43 2622 26700; fax: +43 2622 26700 1369; email: *airworthiness@diamond-air.at.*

(6) You may view this service information at the FAA, Engine & Propeller Directorate, 12 New England Executive Park, Burlington, MA. For information on the availability of this material at the FAA, call 781–238–7125.

(i) Material Incorporated by Reference

(1) The Director of the Federal Register approved the incorporation by reference (IBR) of the service information listed in this paragraph under 5 U.S.C. 552(a) and 1 CFR part 51.

(2) You must use this service information as applicable to do the actions required by this AD, unless the AD specifies otherwise.

(i) Technify Motors Service Bulletin (SB) No. SB TMG 125–1018 P1, Revision 1, dated February 5, 2015.

(ii) Reserved.

(3) For Technify Motors GmbH service information identified in this AD, contact Technify Motors GmbH, Platanenstrasse 14, D–09356 Sankt Egidien, Germany; phone: +49–37204–696–0; fax: +49–37204–696–55; email: *info@centurion-engines.com.*

(4) You may view this service information at FAA, Engine & Propeller Directorate, 12 New England Executive Park, Burlington, MA. For information on the availability of this material at the FAA, call 781–238–7125.

(5) You may view this service information 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.*

Issued in Burlington, Massachusetts, on October 6, 2015.

Ann C. Mollica,

Acting Directorate Manager, Engine & Propeller Directorate, Aircraft Certification Service.

[FR Doc. 2015–26347 Filed 10–22–15; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 71

[Docket No. FAA–2015–2049; Airspace Docket No. 15–AGL–12]

Revocation of Class E Airspace; Vincennes, IN

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Final rule.

SUMMARY: This action removes Class E airspace at O'Neal Airport, Vincennes, IN. Controlled airspace is no longer needed as the airport was abandoned in 2009 and is being removed from the FAAs database.

DATES: Effective 0901 UTC, December 10, 2015. The Director of the Federal Register approves this incorporation by reference action under title 1, Code of Federal Regulations, part 51, subject to the annual revision of FAA Order 7400.9 and publication of conforming amendments.

ADDRESSES: FAA Order 7400.9Z, Airspace Designations and Reporting Points, and subsequent amendments can be viewed on line at *http://www.faa.gov/airtraffic/publications/.* For further information, you can contact the Airspace Policy and ATC Regulations Group, Federal Aviation Administration, 800 Independence Avenue SW., Washington, DC 29591; telephone: 202–267–8783. The Order is also available for inspection 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/code_of_federal-regulations/ibr_locations.html.*

FAA Order 7400.9, Airspace Designations and Reporting Points, is published yearly and effective on September 15.

FOR FURTHER INFORMATION CONTACT: Jim Pharmakis, Operations Support Group, Central Service Center, Federal Aviation Administration, Southwest Region, 10101 Hillwood Parkway, Fort Worth, TX 76177; telephone: (817) 222–5855.

SUPPLEMENTARY INFORMATION:

Authority for This Rulemaking

The FAA's authority to issue rules regarding aviation safety is found in Title 49 of the United States Code. Subtitle I, Section 106 describes the authority of the FAA Administrator. Subtitle VII, Aviation Programs, describes in more detail the scope of the agency's authority. This rulemaking is promulgated under the authority described in Subtitle VII, Part, A, Subpart I, Section 40103. Under that section, the FAA is charged with prescribing regulations to assign the use of airspace necessary to ensure the safety of aircraft and the efficient use of airspace. This regulation is within the scope of that authority as it removes Class E airspace at O'Neal Airport, Vincennes, IN.

History

During an airspace review, the FAA found that O'Neal Airport, Vincennes, IN, has been abandoned since in 2009, therefore, controlled airspace is removed from the area. Since this eliminates the impact of controlled airspace on users of the National Airspace System, notice and public procedure under 553(b) are unnecessary. Class E airspace designations are published in paragraph 6005 of FAA Order 7400.9Z dated August 6, 2015, and effective September 15, 2014, which is incorporated by reference in 14 CFR 71.1. The Class E airspace designations listed in this document will be published subsequently in the Order.

Availability and Summary of Documents for Incorporation by Reference

This document amends FAA Order 7400.9Z, airspace Designations and Reporting Points, dated August 6, 2015, and effective September 15, 2015. FAA Order 7400.9Z is publicly available as listed in the **ADDRESSES** section of this document. FAA Order 7400.9Z lists Class A, B, C, D, and E airspace areas, air traffic service routes, and reporting points.

The Rule

This amendment to Title 14, Code of Federal Regulations (14 CFR) part 71 removes Class E airspace extending upward from 700 feet above the surface within a 7-mile radius of O'Neal Airport, Vincennes, IN. The airport has been abandoned; therefore, controlled airspace is no longer necessary.

Regulatory Notices and Analyses

The FAA has determined that this regulation only involves an established body of technical regulations for which frequent and routine amendments are necessary to keep them operationally current, is non-controversial and unlikely to result in adverse or negative comments. It, therefore: (1) Is not a ''significant regulatory action'' under Executive Order 12866; (2) is not a ''significant rule'' under DOT

Regulatory Policies and Procedures (44 FR 11034; February 26, 1979); and (3) does not warrant preparation of a Regulatory Evaluation as the anticipated impact is so minimal. Since this is a routine matter that only affects air traffic procedures and air navigation, it is certified that this rule, when promulgated, does not have a significant economic impact on a substantial number of small entities under the criteria of the Regulatory Flexibility Act.

Environmental Review

The FAA has determined that this action qualifies for categorical exclusion under the National Environmental Policy Act in accordance with FAA Order 1050.1F, ''Environmental Impacts: Policies and Procedures,'' paragraph 311a. This airspace action is not expected to cause any potentially significant environmental impacts, and no extraordinary circumstances exist that warrant preparation of an environmental assessment.

Lists of Subjects in 14 CFR Part 71

Airspace, Incorporation by reference, Navigation (air).

Adoption of the Amendment

In consideration of the foregoing, the Federal Aviation Administration amends 14 CFR part 71 as follows:

PART 71—DESIGNATION OF CLASS A, B, C, D, AND E AIRSPACE AREAS; AIR TRAFFIC SERVICE ROUTES; AND REPORTING POINTS

■ 1. The authority citation for Part 71 continues to read as follows:

Authority: 49 U.S.C. 106(f), 106(g); 40103, 40113, 40120, E.O. 10854, 24 FR 9565, 3 CFR, 1959–1963 Comp., p. 389.

§ 71.1 [Amended]

■ 2. The incorporation by reference in 14 CFR 71.1 of FAA Order 7400.9Z, Airspace Designations and Reporting Points, dated August 6, 2015, effective September 15, 2015, is amended as follows:

Paragraph 6005 Class E Airspace Areas Extending Upward From 700 Feet or More Above the Surface of the Earth.

* * * * *

AGL IN E5 Vincennes, IN [Removed]

Issued in Fort Worth, TX, on October 8, 2015.

Walter Tweedy,

Acting Manager, Operations Support Group, ATO Central Service Center.

[FR Doc. 2015–26943 Filed 10–22–15; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 71

[Docket No. FAA–2015–1389; Airspace Docket No. 13–ASW–8]

Establishment of Class E Airspace; Vidalia, LA

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Final rule.

SUMMARY: This action establishes Class E airspace at Vidalia, LA. Controlled airspace is necessary to accommodate new Standard Instrument Approach Procedures at Concordia Parish Airport. The FAA is taking this action to enhance the safety and management of Instrument Flight Rules (IFR) operations at the airport.

DATES: Effective 0901 UTC, December 10, 2015. The Director of the Federal Register approves this incorporation by reference action under Title 1, Code of Federal Regulations, part 51, subject to the annual revision of FAA Order 7400.9 and publication of conforming amendments.

ADDRESSES: FAA Order 7400.9Z Airspace Designations and Reporting Points and subsequent amendments can be viewed on line at *http://www.faa.gov/air_traffic/publications.* For further information, you can contact the Airspace Policy and ATC Regulations Group, Federal Aviation Administration, 800 Independence Avenue SW., Washington, DC 29591; telephone: 202–267–8783. The order is also available for inspection 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/code_of_federal-regulations/ibr_locations.html.*

FAA Order 7400.9, Airspace Designations and Reporting Points is published yearly and effective on September 15.

FOR FURTHER INFORMATION CONTACT: Rebecca Shelby, Central Service Center, Operations Support Group, Federal Aviation Administration, Southwest Region, 10101 Hillwood Parkway, Fort Worth, TX 76177; telephone: 817–222–5857.

SUPPLEMENTARY INFORMATION:

Authority for This Rulemaking

The FAA's authority to issue rules regarding aviation safety is found in Title 49 of the United States Code. Subtitle I, Section 106 describes the authority of the FAA Administrator. Subtitle VII, Aviation Programs, describes in more detail the scope of the agency's authority. This rulemaking is promulgated under the authority described in Subtitle VII, Part, A, Subpart I, Section 40103. Under that section, the FAA is charged with prescribing regulations to assign the use of airspace necessary to ensure the safety of aircraft and the efficient use of airspace. This regulation is within the scope of that authority as it establishes controlled airspace at Concordia Parish Airport, Vidalia, LA.

History

On August 13, 2015, the FAA published in the **Federal Register** a notice of proposed rulemaking (NPRM) to establish Class E airspace extending upward from 700 feet above the surface at Concordia Parish Airport, Vidalia, LA, (80 FR 48469). Interested parties were invited to participate in this rulemaking effort by submitting written comments on the proposal to the FAA. No comments were received.

Class E airspace designations are published in paragraph 6005 of FAA Order 7400.9Z, dated August 6, 2015, and effective September 15, 2015, which is incorporated by reference in 14 CFR part 71.1. The Class E airspace designations listed in this document will be published subsequently in the Order.

Availability and Summary of Documents for Incorporation by Reference

This document amends FAA Order 7400.9Z, Airspace Designations and Reporting Points, dated August 6, 2015, and effective September 15, 2015. FAA Order 7400.9Z is publicly available as listed in the ADDRESSES section of this document. FAA Order 7400.9Z lists Class A, B, C, D, and E airspace areas, air traffic service routes, and reporting points.

The Rule

This action amends Title 14, Code of Federal Regulations (14 CFR), Part 71 by establishing Class E airspace extending upward from 700 feet above the surface within a 6.0-mile radius of Concordia Parish Airport, Vidalia, LA, to accommodate new Standard Instrument Approach Procedures at the airport. This action enhances the safety and management of IFR operations at the airport.

Regulatory Notices and Analyses

The FAA has determined that this regulation only involves an established body of technical regulations for which frequent and routine amendments are necessary to keep them operationally current, is non-controversial and unlikely to result in adverse or negative comments. It, therefore: (1) Is not a ''significant regulatory action'' under Executive Order 12866; (2) is not a ''significant rule'' under DOT Regulatory Policies and Procedures (44 FR 11034; February 26, 1979); and (3) does not warrant preparation of a regulatory evaluation as the anticipated impact is so minimal. Since this is a routine matter that only affects air traffic procedures and air navigation, it is certified that this rule, when promulgated, does not have a significant economic impact on a substantial number of small entities under the criteria of the Regulatory Flexibility Act.

Environmental Review

The FAA has determined that this action qualifies for categorical exclusion under the National Environmental Policy Act in accordance with FAA Order 1050.1F, ''Environmental Impacts: Policies and Procedures'' paragraph 311a. This airspace action is not expected to cause any potentially significant environmental impacts, and no extraordinary circumstances exists that warrant preparation of an environmental assessment.

List of Subjects in 14 CFR Part 71

Airspace, Incorporation by reference, Navigation (air).

Adoption of the Amendment

In consideration of the foregoing, the Federal Aviation Administration amends 14 CFR part 71 as follows:

PART 71—DESIGNATION OF CLASS A, B, C, D, AND E AIRSPACE AREAS; AIR TRAFFIC SERVICE ROUTES; AND REPORTING POINTS

■ 1. The authority citation for Part 71 continues to read as follows:

Authority: 49 U.S.C. 106(f), 106(g); 40103, 40113, 40120; E.O. 10854, 24 FR 9565, 3 CFR, 1959–1963 Comp., p. 389

§ 71.1 [Amended]

■ 2. The incorporation by reference in 14 CFR 71.1 of FAA Order 7400.9Z, Airspace Designations and Reporting Points, dated August 6, 2015, and effective September 15, 2015, is amended as follows:

Paragraph 6005 Class E Airspace Areas Extending Upward From 700 feet or More Above the Surface of the Earth.

* * * * *

ASW LA E5 Vidalia, LA [New]

Concordia Parish Airport, LA
(Lat. 31°33′43″ N., long. 91°30′23″ W.)

That airspace extending upward from 700 feet above the surface within a 7.7-mile radius of Concordia Parish Airport, and within 2 miles each side of the 174° bearing from the airport extending from the 7.7 mile radius to 9 miles south of the airport.

Issued in Fort Worth, TX, on October 14, 2015.

Walter Tweedy,

Acting Manager, Operations Support Group, ATO Central Service Center.

[FR Doc. 2015–26947 Filed 10–22–15; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 71

[Docket No. FAA–2015–3322; Airspace Docket No. 15–ANM–16]

Establishment of Class E Airspace; Vancouver, WA

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Final rule.

SUMMARY: This action establishes Class E surface area airspace at Pearson Field, Vancouver, WA, to accommodate existing Standard Instrument Approach Procedures (SIAPS) at the airport. This enhances the safety and management of SIAPs for Instrument Flight Rules (IFR) operations at the airport.

DATES: Effective 0901 UTC, December 10, 2015. The Director of the Federal Register approves this incorporation by reference action under Title 1, Code of Federal Regulations, part 51, subject to the annual revision of FAA Order 7400.9 and publication of conforming amendments.

ADDRESSES: FAA Order 7400.9Z, Airspace Designations and Reporting Points, and subsequent amendments can be viewed online at *http://www.faa.gov/air_traffic/publications/.* For further information, you can contact the Airspace Policy and ATC Regulations Group, Federal Aviation Administration, 800 Independence Avenue SW., Washington, DC 29591; telephone: 202–267–8783. The Order is also available for inspection 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/code_of_federal-regulations/ibr_locations.html.*

FAA Order 7400.9, Airspace Designations and Reporting Points, is published yearly and effective on September 15.

FOR FURTHER INFORMATION CONTACT: Steve Haga, Federal Aviation Administration, Operations Support Group, Western Service Center, 1601 Lind Avenue SW., Renton, WA 98057; telephone (425) 203–4563.

SUPPLEMENTARY INFORMATION:

Authority for This Rulemaking

The FAA's authority to issue rules regarding aviation safety is found in Title 49 of the United States Code. Subtitle I, Section 106 describes the authority of the FAA Administrator. Subtitle VII, Aviation Programs, describes in more detail the scope of the agency's authority. This rulemaking is promulgated under the authority described in Subtitle VII, Part A, Subpart I, Section 40103. Under that section, the FAA is charged with prescribing regulations to assign the use of airspace necessary to ensure the safety of aircraft and the efficient use of airspace. This regulation is within the scope of that authority as it establishes controlled airspace at Pearson Field, Vancouver, WA.

History

On August 27, 2015, the FAA published in the **Federal Register** a notice of proposed rulemaking (NPRM) to establish Class E surface area airspace Pearson Field, Vancouver, WA (80 FR 51970). Interested parties were invited to participate in this rulemaking effort by submitting written comments on the proposal to the FAA. Eight comments were received on the proposal. Seven comments were received supporting the proposal. One comment was received from Bryan Painter stating that the airport did not need Class E surface airspace. The FAA does not agree. The FAA's decision to establish Class E surface airspace at Pearson Field is the result of years of collaborative efforts between local aircraft owner/operators, airport officials, and the FAA to make the airspace safe for aircraft flying within the National Airspace System, specifically within Portland International Airport airspace.

Class E airspace designations are published in paragraph 6002 of FAA Order 7400.9Z, dated August 6, 2015, and effective September 15, 2015, which is incorporated by reference in 14 CFR part 71.1. The Class E airspace designation listed in this document will be published subsequently in the Order.

Availability and Summary of Documents for Incorporation by Reference

This document amends FAA Order 7400.9Z, Airspace Designations and Reporting Points, dated August 6, 2015, and effective September 15, 2015. FAA Order 7400.9Z is publicly available as listed in the **ADDRESSES** section of this document. FAA Order 7400.9Z lists Class A, B, C, D, and E airspace areas, air traffic service routes, and reporting points.

The Rule

This amendment to Title 14, Code of Federal Regulations (14 CFR) part 71 establishes Class E surface area airspace, at Pearson Field, Vancouver, WA. A review of the airspace revealed current standard instrument approach procedures not being fully contained within controlled airspace. Class E surface area airspace is established within an area 4.9 miles west, 4 miles east, 2.9 miles north, and 1.8 miles south of Pearson Field.

Regulatory Notices and Analyses

The FAA has determined that this regulation only involves an established body of technical regulations for which frequent and routine amendments are necessary to keep them operationally current, is non-controversial and unlikely to result in adverse or negative comments. It, therefore: (1) Is not a ''significant regulatory action'' under Executive Order 12866; (2) is not a ''significant rule'' under DOT Regulatory Policies and Procedures (44 FR 11034; February 26, 1979); and (3) does not warrant preparation of a Regulatory Evaluation as the anticipated impact is so minimal. Since this is a routine matter that only affects air traffic procedures and air navigation, it is certified that this rule, when promulgated, does not have a significant economic impact on a substantial number of small entities under the criteria of the Regulatory Flexibility Act.

Environmental Review

The FAA has determined that this action qualifies for categorical exclusion under the National Environmental Policy Act in accordance with FAA Order 1050.1F, ''Environmental Impacts: Policies and Procedures,'' paragraph 311a. This airspace action is not expected to cause any potentially significant environmental impacts, and no extraordinary circumstances exist that warrant preparation of an environmental assessment.

Lists of Subjects in 14 CFR Part 71

Airspace, Incorporation by reference, Navigation (air).

Adoption of the Amendment

In consideration of the foregoing, the Federal Aviation Administration amends 14 CFR part 71 as follows:

PART 71—DESIGNATION OF CLASS A, B, C, D, AND E AIRSPACE AREAS; AIR TRAFFIC SERVICE ROUTES; AND REPORTING POINTS

■ 1. The authority citation for Part 71 continues to read as follows:

Authority: 49 U.S.C. 106(f), 106(g); 40103, 40113, 40120; E.O. 10854, 24 FR 9565, 3 CFR, 1959–1963 Comp., p. 389.

§ 71.1 [Amended]

■ 2. The incorporation by reference in 14 CFR 71.1 of FAA Order 7400.9Z, Airspace Designations and Reporting Points, dated August 6, 2015, and effective September 15, 2015, is amended as follows:

Paragraph 6002 Class E Airspace Designated as Surface Areas.

* * * * *

ANM OR E2 Vancouver, WA [New]

Pearson Field, WA

(Lat. 45°37′14″ N., Long. 122°39′23″ W.)

That airspace extending upward from the surface bounded by a line beginning at Lat. 45°36′06″ N., Long. 122°46′29″ W.; to Lat. 45°38′27″ N., Long. 122°46′19″ W.; to Lat. 45°40′21″ N., Long. 122°44′08″ W.; to Lat. 45°39′49″ N., Long. 122°33′23″ W.; to Lat. 45°34′51″ N., Long. 122°33′53″ W.; thence to the point of beginning.

Issued in Seattle, Washington, on October 15, 2015.

Christopher Ramirez,

Manager, Operations Support Group, Western Service Center.

[FR Doc. 2015–26948 Filed 10–22–15; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF STATE

22 CFR Part 11

[Public Notice: 9324]

RIN 1400–AD59

Appointment of Foreign Service Officers

AGENCY: Department of State.

ACTION: Final rule.

SUMMARY: The Department of State amends provisions in the Code of Federal Regulations related to the appointment of Foreign Service Officers. The revised rules will be substantially the same as, and will supplement, Department of State guidance currently in the Foreign Affairs Manual, which is also available to the public.

DATES: This rule will be effective on November 23, 2015.

FOR FURTHER INFORMATION CONTACT: Alice Kottmyer, Office of the Legal Adviser, who may be reached at (202) 647–2318.

SUPPLEMENTARY INFORMATION: Pursuant to Section 206 of the Foreign Service Act of 1980 (the Act), codified at 22 U.S.C. 3926, the Secretary of State may prescribe regulations to carry out functions under the Act. The Secretary has done so in the Department's Foreign Affairs Manual (FAM).

The FAM is the formal written document for recording, maintaining, and issuing Department directives, which are written communications establishing and prescribing the organizations, policies, or procedures that provide an official basis of Department operation.

The Foreign Service includes personnel not only from the Department, but U.S. Agency for International Development, and certain offices within the Departments of Commerce and Agriculture, among others. FSOs may be recruited both from current federal personnel (for example, from the civil service) and from the general public. Recruitment from current federal service is covered by the FAM.

The procedures relating to recruitment of FSOs from the general public are covered by rules published in the CFR, in part 11. However, since many of the policies and procedures dealing with the latter appointments are the same as those used to appoint current federal personnel to the Foreign Service, the provisions of part 11 and the FAM must be consistent. Therefore, where part 11 uses the same procedures as the FAM, it refers to the relevant FAM provisions.

Other than a minor amendment in 2002 (*see* 67 FR 46108), part 11 has remained as it was drafted 31 years ago; whereas, the relevant provisions of the FAM were updated in 2013. This rulemaking harmonizes the two authorities. The Department believes that a revised part 11, together with the FAM, provide comprehensive guidance for both internal stakeholders and interested members of the general public on the appointment of Foreign Service Officers.

The Department's revision of part 11 is part of its Retrospective Review conducted pursuant to Executive Order 13563.

Regulatory Findings

Administrative Procedure Act

The revision to part 11 of 22 CFR relates to the Department's organization, procedure, or practice and is not subject to the notice-and-comment procedures of 5 U.S.C. 553(b).

Regulatory Flexibility Act/Executive Order 13272: Small Business

The Department certifies that this rulemaking is not expected to have a significant impact on a substantial number of small entities under the criteria of the Regulatory Flexibility Act, 5 U.S.C. 601–612, and Executive Order 13272, section 3(b).

The Congressional Review Act

This rulemaking is not a major rule as defined by 5 U.S.C. 804, for purposes of congressional review of agency rulemaking.

The Unfunded Mandates Reform Act of 1995

Section 202 of the Unfunded Mandates Reform Act of 1995, 2 U.S.C. 1532, generally requires agencies to prepare a statement before proposing or adopting any rule that may result in an annual expenditure of $100 million or more by state, local, or tribal governments, or by the private sector. This rulemaking will not result in any such expenditure nor will it significantly or uniquely affect small governments.

Executive Orders 12372 and 13132: Federalism

This rulemaking 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. Nor will the rule have federalism implications warranting the application of Executive Orders 12372 and 13132.

Executive Orders 12866 and 13563: Regulatory Review

Although the Department of State is generally exempt from the provisions of Executive Order 12866, it has reviewed this rulemaking to ensure its consistency with the regulatory philosophy and principles set forth in these Executive Orders, and has determined that the benefits of this rulemaking justify any costs. The Department cannot identify any cost to the public associated with this rulemaking. The Department does not consider this rulemaking to be a significant regulatory action within the scope of section 3 of Executive Order 12866. The Department considers this rule to be part of its Retrospective Review conducted pursuant to Executive Order 13563.

Executive Order 12988: Civil Justice Reform

The Department has reviewed this rulemaking in light of sections 3(a) and 3(b)(2) of Executive Order 12988 to eliminate ambiguity, minimize litigation, establish clear legal standards, and reduce burden.

Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

The Department has determined that this rulemaking will not have tribal implications, will not impose substantial direct compliance costs on Indian tribal governments, and will not pre-empt tribal law. Accordingly, the requirements of Section 5 of Executive Order 13175 do not apply to this rulemaking.

The Paperwork Reduction Act of 1995

The Department of State has determined that this rulemaking does not affect any existing collection of information under the Paperwork Reduction Act, nor does it create new information collections. The Department invites public comment on whether the Foreign Service Office Test Registration (OMB Control Number 1405–0008) burden estimates should be modified as a result of the notification requirements in Section 11.20(d)(2)(i)(B).

List of Subjects in 22 CFR Part 11

Foreign service, Foreign officials, Government employees.

Accordingly, revise 22 CFR part 11 to read as follows:

PART 11—APPOINTMENT OF FOREIGN SERVICE OFFICERS

Sec.

Authority: 22 U.S.C. 2651a, 3926, 3941.

§ 11.10 Links to relevant provisions of the Foreign Affairs Manual.

(a) The Foreign Affairs Manual (FAM) is the formal written document for recording, maintaining, and issuing Department of State (Department) directives that address personnel and other matters. It is the primary authority for appointment of current Department employees to the Foreign Service. This part is the primary authority for the appointment of non-employees to the Foreign Service. The FAM provides Department procedures and policies that are not repeated in this part. It is an important resource for understanding the provisions of this part.

(b) The two FAM volumes relevant to this part are Volume 3, Personnel, and Volume 16, Medical. FAM provisions are cited by volume followed by chapter or subchapter—for example, Chapter 210 of Volume 16 would be cited 16 FAM 210. All of the relevant FAM provisions are on the Department's public Web site. The links for the relevant FAM provisions are as follows:

3 FAM 2215	*http://www.state.gov/documents/organization/84854.pdf.*
3 FAM 2216.2	
3 FAM 2216.3	
3 FAM 2217	
3 FAM 2218	
3 FAM 2245	*http://www.state.gov/documents/organization/84851.pdf.*
3 FAM 2250	*http://www.state.gov/documents/organization/84850.pdf.*
3 FAM 2251.3	
3 FAM 2290	*http://www.state.gov/documents/organization/84846.pdf.*
16 FAM 210	*http://www.state.gov/documents/organization/89692.pdf.*

§ 11.20 Entry-level Foreign Service Officer career candidate appointments.

(a) *General considerations*—(1) *Authority.* Pursuant to section 302 of the Foreign Service Act of 1980 (hereinafter referred to as ''the Act''), all Foreign Service Officers shall be appointed by the President, by and with the advice and consent of the Senate. All appointments shall be made to a class and not to a particular post. No person shall be eligible for appointment as a Foreign Service Officer unless that person is a citizen of the United States, is twenty-one, and is world-wide available. Pursuant to section 306 of the Act, such appointment is initially a career-candidate appointment. The tenuring of Foreign Service Officer career candidates is governed by the provisions of 3 FAM 2245.

(2) *Veterans' preference.* Pursuant to section 301 of the Act, the fact that an applicant for appointment as a Foreign Service Officer candidate is a veteran or disabled veteran, as defined in 5 U.S.C. 2108, must be considered as an affirmative factor in making such appointments.

(3) *Policy.* Appointment as an Entry Level Foreign Service Officer career candidate of class 6, 5, or 4 is governed by these regulations. Successful applicants will be appointed as career candidates for a period not to exceed 5 years. Under precepts of the Commissioning and Tenure Board, career candidates may be granted tenure and recommended for appointment as career Foreign Service Officers. Those who are not granted tenure prior to the expiration of their career-candidate appointments will be separated from the Foreign Service. Separated candidates who originally were employees of an agency and who accepted a limited appointment to the Foreign Service with the consent of the head of the agency in which they were employed will be entitled to reemployment rights in their former agency in accordance with section 310 of the Act.

(b) *The Foreign Service Officer Test (FSOT).* The following regulations apply to the FSOT:

(1) *Purpose.* The FSOT is designed to enable the Board of Examiners for the Foreign Service to test the applicant's knowledge, skills, and abilities, including writing skills that are necessary to the work of a Foreign Service Officer.

(2) *Eligibility.* Before each FSOT, the Board of Examiners will establish a closing date for the receipt of applications for designation to take the test. No person will be designated to take the test who has not, as of that closing date, filed a complete application with the Board. To be designated to take the FSOT, an applicant, as of the date of the test, must be a citizen of the United States and at least 20 years of age.

(3) *When and where given.* The FSOT will be given periodically, in designated cities in the United States and at selected locales abroad, on dates established by the Board of Examiners and publicly announced on *careers.state.gov.*

(4) *Scoring.* The several parts of the FSOT will be weighted and graded according to standards established by the Board of Examiners. The Board of Examiners may adjust the passing score of the FSOT to reflect the projected hiring needs of the Foreign Service.

(c) *Qualifications Evaluation Panel (QEP).* The following regulations apply to the QEP:

(1) *Purpose.* Each QEP is designed to enable the Board of Examiners for the Foreign Service to review each candidate's file and evaluate it against established precepts of successful Foreign Service Officer performance. The QEPs rank order candidates within each career track.

(2) *Panels.* QEPs are career track specific and are staffed by panelists approved by the Board of Examiners from a roster of qualified active duty and retired Foreign Service Officers. At least one of the panelists will be from the same career track as those in the candidate pool.

(3) *Eligibility.* Candidates whose score on the FSOT is at or above the passing level set by the Board of Examiners will be invited to submit their responses to Personal Narrative Questions. The questions, linked to the Foreign Service performance precepts, are designed to elicit specific examples of past performance where the candidate demonstrated the requisite precept.

(4) *When administered.* The Board of Examiners holds one session of QEPs following each FSOT.

(5) *Scoring.* Panelists will score files according to standards established by the Board of Examiners. The candidacy of anyone whose score is at or above the passing level set by the Board of Examiners will continue. The candidacy of anyone whose score is below the passing level will be ended and may not be considered again until the candidate has passed a new FSOT, at minimum of a year later. The Board of Examiners sets the passing score for each QEP based on the projected hiring needs of the Foreign Service. All candidates exempt from the FSOT, except Mustang applicants, are also exempt from review by a QEP.

(i) The Board of Examiners may authorize QEPs to give special consideration in the selection of candidates to certain factors, *e.g.,* demonstrating language ability, which the Board will publicly announce on *careers.state.gov.*

(ii) The Board of Examiners may choose to verify accounts given by candidates in their personal narratives.

(d) *Foreign Service Oral Assessment (FSOA).* The following regulations apply to the FSOA:

(1) *Purpose.* The FSOA is designed to enable the Board of Examiners for the Foreign Service to test the candidate's ability to demonstrate the qualities or dimensions that are essential to the successful performance of Foreign Service work. The FSOA for the Entry Level Foreign Service Officer Career Candidate Program will consist of an assessment procedure publicly announced by the Board of Examiners on *careers.state.gov.* The process is generally referred to as the Foreign Service Oral Assessment or FSOA.

(2) *Eligibility*—(i) *Through the FSOT and QEP review.* (A) Candidates who pass the FSOT and whose score on the QEP review is at or above the passing level set by the Board of Examiners will be invited to take the FSOA.

(B) Candidates must schedule the FSOA within 12 months of receiving their invitation to take the FSOA unless they receive an extension of time. Candidates may request an extension of up to an additional 12 months. Active duty military have unrestricted time to take an FSOA if they notify the Board of Examiners of their active duty status. Failure to take the FSOA within 12 months of the invitation will result in the cancellation of the candidacy, unless the candidate has requested and obtained an extension of eligibility. The candidacy of anyone for whom the scheduling period is extended by the Board due to being outside of the United States will automatically be terminated if the candidate fails to notify his or her registrar of the change in status within three months of returning to the United States. The candidate must schedule an FSOA, but if a candidate fails to appear for a scheduled FSOA, the candidacy is automatically terminated. The Director of the Office of Recruitment, Examination, and Employment in the Bureau of Human Resources, or his/her designee, will consider requests to reschedule on a case-by-case basis if a candidate so requests prior to his/her scheduled FSOA.

(ii) *Through the Mustang Program.* Career employees of the Department of State in classes FS–6 and above or grades GS–5 and above who are at least 21 years of age and who have at least three years of service with the

Department may be selected by the Board of Examiners for admission to the FSOA for Entry Level Career Candidates under the Department's Mustang Program. Mustang candidates must meet all program requirements and submit all application material to be considered for the Mustang Program. See the procedures set forth in 3 FAM 2216.2–4 (Foreign Service Officer Oral Assessment (FSOA)).

(iii) *Through a mid-level conversion program.* Employees of the Department of State in grade GS–13 and above are eligible to apply to enter the Foreign Service through a mid-level conversion program (see 3 FAM 2216.3–2) whenever held.

(iv) *Through other programs.* (A) Under programs established pursuant to section 105(d)(1) of the Act, which addresses diversity within the Foreign Service.

(B) Under any other special entry programs created by the Department to meet specific needs of the Foreign Service.

(3) *When and where given.* The FSOA will be held intermittently in Washington, DC, and may be held in selected cities in the United States or abroad as necessary, as publicly announced.

(4) *Assessment panel.* (i) The FSOA will be given by a panel of assessors approved by the Board of Examiners from a roster of active duty and/or retired Foreign Service Officers.

(ii) Service as an assessor shall be limited to a maximum of 5 years, unless a further period is specifically authorized by the Board. Normally assessment panels shall be chaired by a career officer of the Foreign Service, trained in personnel testing and evaluation. Determinations of duly constituted panels of assessors are final unless modified by specific action of the Board of Examiners.

(5) *Scoring.* Candidates taking the FSOA will be scored numerically according to standards established and publicly announced by the Board of Examiners, in places such as *careers.state.gov.* The candidacy of anyone whose score is at or above the passing level set by the Board will be continued. The candidacy of anyone whose score is below the passing level will be terminated.

(e) *Background investigation.* Candidates who pass the FSOA and elect to continue the hiring process will be subject to a background investigation. The background investigation must be conducted to determine the candidate's eligibility for a security clearance and serves as the basis for determining suitability for appointment to the Foreign Service (see 3 FAM 2212.1 (Security Investigation)).

(f) *Medical examination*—(1) *Eligibility.* Candidates who pass the oral assessment and elect to continue the hiring process must undergo a medical examination. See the procedures in of 16 FAM 210 (Medical Clearances).

(2) [Reserved]

(g) *Suitability Review Panel.* Generally after the medical clearance has been issued and the background investigation is received, the candidate's entire file (excluding any medical records) is reviewed and evaluated by the Suitability Review Panel to determine the candidate's suitability for the Foreign Service. See the procedures in 3 FAM 2215 (Suitability Review). The candidacy of any candidate who is determined by the Suitability Review Panel to be unsuitable for appointment shall be terminated and the candidate so informed. According to procedures established by the Board of Examiners, a candidate may appeal this decision to the Board of Examiners Staff Director or designee whose decision will be final. The Bureau of Diplomatic Security (DS) will re-submit applicants to the Suitability Review Panel if they are found to have falsified information in the application process or are found to have disqualifying factors.

(h) *Certification for appointment*—(1) *Eligibility.* (i) A candidate will not be certified as eligible for appointment as a Foreign Service Officer Career Candidate unless that candidate is at least 21 years of age and a citizen of the United States.

(ii) Except for preference eligible individuals, career candidate appointments must be made before the candidate's 60th birthday. Preference eligible individuals must be appointed before their 65th birthday. The maximum age for appointment under this program is based on the requirement that all career candidates must be able to:

(A) Complete at least two full tours of duty, exclusive of orientation and training;

(B) Complete the requisite eligibility period for tenure consideration; and

(C) Complete the requisite eligibility period to receive retirement benefits, prior to reaching the mandatory retirement age of 65 prescribed by the Act.

(iii) A candidate may be certified as eligible for direct appointment to classes FS–6, FS–5 or FS–4 based on established, publicly available, criteria.

(iv) Employees who receive a career candidate appointment, *i.e.,* who are untenured, have five years to obtain tenure. These career-candidate appointments, including the appointment of an individual who is the employee of any agency, may not exceed five years in duration, and may not be renewed or be extended beyond five years. A candidate denied tenure under 3 FAM 2250 may not be reappointed as a career candidate to become a generalist.

(2) *Career-track rank-order registers.* The Board of Examiners maintains separate rank-order registers for career candidates in administrative, consular, economic, public diplomacy and political career tracks within the Department of State. Appointments from each career-track register will be made in rank order according to hiring needs.

(3) *Special programs.* Mustang candidates who are career employees of the Department of State and who have satisfactorily completed all aspects of the assessment process will be certified by the Board of Examiners for placement on the Hiring Register to compete for a hiring opportunity as a Foreign Service Officer. Mustang candidates who have previously passed the FSOT/QEP will continue in the career track they selected when registering for the FSOT and be placed on the appropriate career track register.

(4) *Foreign language requirement.* A candidate may be certified for appointment to classes FS–6, FS–5, or FS–4 without first having passed an examination in a foreign language, but the appointment will be subject to the condition that the newly appointed career candidate may not be appointed as a career Foreign Service Officer unless, within a specified period of time, proficiency in a foreign language is achieved.

(i) *Termination of eligibility*—(1) *Time limit.* Candidates who have qualified but have not been appointed because of lack of openings will be removed from the rank-order register 18 months after the date of placement on the rank-order register. Time spent in civilian Federal Government service abroad (to a maximum of 2 years of such service), including Peace Corps volunteer service, spouses of Foreign Service officers, or in active regular or reserve military service (no maximum), will not be counted as part of the 18-month eligibility period.

(2) *Extension.* The Board of Examiners may extend the eligibility period when such extension is, in its discretion, justified by the needs of the Foreign Service.

(3) *Postponement of entrance on duty.* Postponement of entrance on duty because of civilian Federal Government service abroad (to a maximum of 2 years

of such service), including Peace Corps volunteer service, or as spouse of a Foreign Service Officer, or active regular or reserve military service (to a maximum of the limit of such required service), may be authorized by the Board.

(j) *Travel expenses.* The travel and other personal expenses of candidates incurred in connection with the written and oral examination will not be borne by the Government. However, the participating foreign affairs departments may issue round-trip invitational travel orders to bring candidates to Washington, DC, at government expense, when it is determined by the agencies that this is necessary in the interest of the Foreign Service.

§ 11.30 Mid-level Foreign Service Officer career candidate appointments. [Reserved]

§ 11.40 Senior Foreign Service Officer career candidate appointments. [Reserved]

§ 11.50 Foreign Service specialist career candidate appointments.

(a) *General considerations.* (1) Pursuant to section 303 of the Act, the Secretary may appoint individuals to the Foreign Service (other than those who are in the personnel categories specified in section 302(a) of the Act). Pursuant to section 306 of the Act, such appointment is initially a career candidate appointment. Section 303 governs the appointment by the Department of State of Foreign Service specialist career candidates to classes FS–1 and all classes below. Specialist candidates comprise all candidates for career appointment in all career tracks other than generalist career tracks (*i.e.,* management, consular, economic, political, and public diplomacy). The tenuring of specialist career candidates is governed by the procedures in 3 FAM 2250.

(2) Veterans' preference shall apply to the selection and appointment of Foreign Service specialist career candidates. Veterans' preference is an affirmative factor once the candidate has been qualified for the position. As soon as veterans go on the Hiring Register, they may apply for additional points to increase their rank order standing.

(b) *Specialist career candidate appointments*—(1) *Certification of need.* (i) Candidates for appointment as specialist career candidates must be world-wide available and must have a professional or a functional skill for which there is a continuing need in the Foreign Service. No applicant shall be appointed for which there is no certified need established at a specific class level. Either the Director General may determine in advance which specialties are routinely or frequently in shortage or need periodic recruitment through publicly posted vacancy announcements, or the Director General may certify that there is a need for an applicant in a specific specialist category and at a specific class.

(ii) Candidates who receive a career candidate appointment, *i.e.,* who are untenured, have four years with the possibility of five years (see 3 FAM 2251.3) to obtain tenure. These appointments, including the appointment of an individual who is the employee of any agency, may not exceed five years in duration, and may not be renewed or be extended beyond five years. A specialist candidate denied tenure under 3 FAM 2250 generally may not be reappointed as a career candidate in the same career track.

(2) *Eligibility.* An applicant must be a citizen of the United States and at least 20 years of age. The minimum age for appointment as a career candidate is 21. Except for preference eligible candidates, all career candidate appointments shall be made before the candidate's 60th birthday. Preference eligible candidates may be appointed up to their 65th birthday. The maximum age for appointment under the program is based on the requirement that all career candidates shall be able to:

(i) Complete at least two full tours of duty, exclusive of orientation and training,

(ii) Complete the requisite eligibility period for tenure consideration, and

(iii) Complete the requisite eligibility period to receive retirement benefits, prior to reaching the mandatory retirement age of 65 prescribed by the Act.

(3) *Screening.* (i) Specialist career candidates will be screened initially on the basis of education and experience.

(ii) Based on a job analysis, the Board of Examiners, in coordination with any bureau responsible for the specialty, will establish the knowledge, skills, and abilities required to perform successfully the tasks and duties of Foreign Service specialists in that functional field. Assessors working for the Board of Examiners will screen applications under those approved criteria and select those who meet the requirements to invite to an oral assessment.

(4) *Oral assessment.* Candidates are selected through the initial screening process. The oral assessment will be given by a panel of assessors, at least one of whom will be a career Foreign Service employee proficient in the functional field for which the candidate is being tested. The assessment may include a writing sample. Candidates taking the oral assessment will be scored numerically according to standards set by the Board of Examiners. The candidacy of anyone whose score is at or above the passing level set by the Board will be continued. The candidacy of anyone whose score is below the passing level will be terminated. The candidate may only reapply after the first anniversary date of the original application.

(5) *Background investigation.* Specialist candidates who pass the oral assessment and elect to continue the hiring process will be subject to a background investigation. The background investigation must be conducted to determine the candidate's eligibility for a security clearance and serves as the basis for determining suitability for appointment to the Foreign Service (see 3 FAM 2212.1–1 (Security Investigation)).

(6) *Medical examination.* Candidates who pass the oral assessment and elect to continue the hiring process must undergo a medical examination. See the procedures in 16 FAM 210 (Medical Clearances).

(7) *Suitability Review Panel.* After the medical examination clearance has been issued and the background investigation is received, the candidate's entire file (excluding any medical records) is reviewed and evaluated by a Suitability Review Panel to determine the candidate's suitability for the Foreign Service. See the procedures in 3 FAM 2215 (Suitability Review). According to procedures established by the Board of Examiners, a candidate may appeal this decision to the Board of Examiners Staff Director or designee, whose decision will be final. DS will re-submit applicants to the Suitability Review Panel if they are found to have falsified information on their application or are found to have disqualifying factors.

§ 11.60 Limited non-career appointments.

Consistent with section 303 of the Act (22 U.S.C. 3943), the Secretary of State may also appoint Civil Service employees and other individuals to the Foreign Service, and, consistent with section 309 of the Act (22 U.S.C. 3949), such appointments may include limited non-career appointments (LNAs). After meeting the job specific requirements, candidates must meet applicable medical, security, and suitability requirements. Limited non-career appointments are covered under 3 FAM 2290.

Dated: September 11, 2015.

Arnold A. Chacon,

Director General of the Foreign Service and Director of Human Resources.

[FR Doc. 2015–27026 Filed 10–22–15; 8:45 am]

BILLING CODE 4710–15–P

DEPARTMENT OF HOMELAND SECURITY

Coast Guard

33 CFR Part 117

[Docket No. USCG–2015–0973]

Drawbridge Operation Regulations; York River, Yorktown, VA

AGENCY: Coast Guard, DHS.

ACTION: Notice of deviation from drawbridge regulations.

SUMMARY: The Coast Guard has issued a temporary deviation from the operating schedule that governs the Coleman Memorial Bridge (US 17) across the York River, mile 7.0, at Yorktown, VA. This deviation allows the bridge to remain in the closed-to-navigation position to facilitate mechanical repairs to the bridge.

DATES: This deviation is effective from 10 p.m. on November 14, 2015, until 7 a.m. on November 22, 2015.

ADDRESSES: The docket for this deviation, [USCG–2015–0973], is available at *http://www.regulations.gov.* Type the docket number in the ''SEARCH'' box and click ''SEARCH''.

FOR FURTHER INFORMATION CONTACT: If you have questions on this temporary deviation, call or email Mr. Hal R. Pitts, Bridge Administration Branch Fifth District, Coast Guard; telephone (757) 398–6222, email *Hal.R.Pitts@uscg.mil.*

SUPPLEMENTARY INFORMATION: The Virginia Department of Transportation, who owns and operates the Coleman Memorial Bridge (US 17), has requested a temporary deviation from the current operating regulations to facilitate mechanical repairs to the movable grating between one of the movable spans and the fixed bridge. The bridge is a swing bridge and has a vertical clearance in the closed position of 60 feet above mean high water.

The current operating schedule is set out in 33 CFR 117.1025. Under this temporary deviation, the bridge will remain in the closed-to-navigation position from 10 p.m. on November 14, 2015, until 7 a.m. on November 15, 2015. If necessary due to inclement weather on November 14, 2015, the bridge will remain in the closed-to-navigation position from 10 p.m. on November 21, 2015, until 7 a.m. on November 22, 2015. The York River is used by a variety of vessels including deep draft ocean-going vessels, U.S. government vessels, small commercial fishing vessels, recreational vessels and tug and barge traffic. The Coast Guard has carefully coordinated the restrictions with U.S. government and commercial waterway users.

Vessels able to pass through the bridge in the closed position may do so at anytime. The bridge will not be able to open for emergencies and there is no alternate route for vessels unable to pass through the bridge in the closed position. The Coast Guard will also inform the users of the waterways through our Local and Broadcast Notice to Mariners of the change in operating schedule for the bridge so that vessels can arrange their transits to minimize any impacts caused by this temporary deviation.

In accordance with 33 CFR 117.35(e), the drawbridge must return to its regular operating schedule immediately at the end of the effective period of this temporary deviation. This deviation from the operating regulations is authorized under 33 CFR 117.35.

Dated: October 19, 2015.

Hal R. Pitts,

Bridge Program Manager, Fifth Coast Guard District.

[FR Doc. 2015–26969 Filed 10–22–15; 8:45 am]

BILLING CODE 9110–04–P

DEPARTMENT OF HOMELAND SECURITY

Coast Guard

33 CFR Part 117

[Docket No. USCG–2015–0947]

Drawbridge Operation Regulation; Snohomish River, Marysville, WA

AGENCY: Coast Guard, DHS.

ACTION: Notice of temporary deviation from regulations.

SUMMARY: The Coast Guard has issued a temporary deviation from the operating schedule that governs the Burlington Northern Santa Fe Railroad Company (BNSF) Bridge 37.0 across the Snohomish River, mile 3.5 at Marysville, WA. The deviation is necessary to accommodate scheduled bridge rail joint maintenance and replacement. The deviation allows the bridges to remain in the closed-to-navigation position during the maintenance to allow safe movement of work crews.

DATES: This deviation is effective from November 1, 2015 through November 15, 2015.

ADDRESSES: The docket for this deviation, [USCG–2015–0947] is available at *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 deviation.

FOR FURTHER INFORMATION CONTACT: If you have questions on this temporary deviation, call or email the Bridge Administrator, Coast Guard Thirteenth District; telephone 206–220–7234 email *d13-pf-d13bridges@uscg.mil.*

SUPPLEMENTARY INFORMATION: BNSF has requested a temporary deviation from the operating schedule for the BNSF RR Bridge 37.0, mile 3.5, crossing Snohomish River, at Marysville, WA. BNSF requested the BNSF RR Bridge 37.0 remain in the closed-to-navigation position for rail maintenance. This maintenance has been scheduled, and is funded as part of the Cascade Corridor Improvement Project.

The normal operating schedule for this bridge operates in accordance with 33 CFR 117.5 which states it must open promptly on signal at any time, and requires constant attendance by with a drawtender. BNSF RR Bridge 37.0 provides 10 feet of vertical clearance in the closed-to-navigation position.

This deviation allows the BNSF RR Bridge 37.0, at mile 3.5 crossing Snohomish River, to remain in the closed-to-navigation position, and need not open for maritime traffic from 10 a.m. until 4 p.m. from November 1, 2015 through November 15, 2015; except, the bridge will remain in the closed-to-navigation position from 8 a.m. until Midnight on November 10, 2015 and from 8 a.m. until Midnight on November 12, 2015. The bridge shall operate in accordance to 33 CFR part 117, subpart A at all other times.

Vessels able to pass through the bridge in the closed-to-navigation position may do so at anytime. The bridge will be required to open, if needed, for vessels engaged in emergency response operations during this closure period, but any time lost to emergency openings will necessitate a time extension added to the approved dates. Waterway usage on this part of the Snohomish River includes tug and barge to small pleasure craft. No immediate alternate route for vessels to pass is available on this part of the river. The Coast Guard will also inform the users of the waterways through our Local and Broadcast Notices to Mariners of the change in operating schedule for the bridge so that vessels can arrange their transits to minimize any impact caused by the temporary deviation.

In accordance with 33 CFR 117.35(e), the drawbridges must return to their regular operating schedule immediately at the end of the effective period of this temporary deviation. This deviation from the operating regulations is authorized under 33 CFR 117.35.

Dated: October 19, 2015.

Steven M. Fischer,

Bridge Administrator, Thirteenth Coast Guard District.

[FR Doc. 2015–26922 Filed 10–22–15; 8:45 am]

BILLING CODE 9110–04–P

DEPARTMENT OF THE INTERIOR

National Park Service

36 CFR Part 13

[NPS–AKRO–18755; PPAKAKROZ5, PPMPRLE1Y.L00000]

RIN 1024–AE21

Alaska; Hunting and Trapping in National Preserves

AGENCY: National Park Service, Interior.

ACTION: Final rule.

SUMMARY: The National Park Service is amending its regulations for sport hunting and trapping in national preserves in Alaska. This rule provides that the National Park Service does not adopt State of Alaska management actions or laws or regulations that authorize taking of wildlife, which are related to predator reduction efforts (as defined in this rule). This rule affirms current State prohibitions on harvest practices by adopting them as federal regulation. The rule also prohibits the following activities that are allowed under State law: Taking any black bear, including cubs and sows with cubs, with artificial light at den sites; taking brown bears and black bears over bait; taking wolves and coyotes during the denning season; harvest of swimming caribou or taking caribou from a motorboat while under power; and using dogs to hunt black bears. The rule also simplifies and updates procedures for closing an area or restricting an activity in National Park Service areas in Alaska; updates obsolete subsistence regulations; prohibits obstructing persons engaged in lawful hunting or trapping; and authorizes the use of native species as bait for fishing.

DATES: This rule is effective November 23, 2015.

FOR FURTHER INFORMATION CONTACT: Andee Sears, Regional Law Enforcement Specialist, Alaska Regional Office, 240 West 5th Ave., Anchorage, AK 99501. Phone (907) 644–3417. Email: *AKR_Regulations@nps.gov*

SUPPLEMENTARY INFORMATION:

Background

Proposed Rule and Public Comment Period

On September 4, 2014, the National Park Service (NPS) published the proposed rule in the **Federal Register** (79 FR 52595). The rule was open for public comment for 90 days, until December 3, 2014. The NPS reopened the comment period from January 15, 2015 through February 15, 2015 (80 FR 2065). The NPS invited comments through the mail, hand delivery, and through the Federal eRulemaking Portal at *http://www.regulations.gov.*

During the first comment period in 2014, the NPS held 17 public hearings in various locations in Alaska. Approximately 168 individuals attended these hearings and approximately 120 participants provided testimony during the formal public comment sessions. During the second comment period, nine public meetings were held in the State. A total of 29 individuals attended the public meetings, and a total of nine attendees spoke during the formal public comment sessions. The NPS also held two statewide government-to-government consultation teleconferences, and offered to consult in person, with tribes. Four comments were received during the statewide government-to-government consultation conference calls and the NPS met with three tribes that requested consultation in person (Allakaket, Tazlina, and Chesh'na (Chistochina)).

The NPS received approximately 70,000 comments on the proposed rule during the public comment period. These included unique comment letters, form letters, and signed petitions. Approximately 65,000 comments were form letters. The NPS also received three petitions with a combined total of approximately 75,000 signatures. Some commenters sent comments by multiple methods. NPS attempted to match such duplicates and count them as one comment. Additionally, many comments were signed by more than one person. NPS counted a letter or petition as a single comment, regardless of the number of signatories.

A summary of comments and NPS responses is provided below in the section entitled ''Summary of and Responses to Public Comments.'' After considering the public comments and additional review, the NPS made some changes in the final rule from that proposed. These changes are summarized below in the section entitled ''Changes from the Proposed Rule.''

Federal and State Mandates for Managing Wildlife.

In enacting the Alaska National Interest Lands Conservation Act (ANILCA) (16 U.S.C. 410hh–410hh–5; 3101–3233) in 1980, Congress's stated purpose was to establish in Alaska various conservation system units that contain nationally significant values, including units of the National Park System, in order to preserve them ''for the benefit, use, education, and inspiration of present and future generations[.]'' 16 U.S.C. 3101(a). Included among the express purposes in ANILCA are preservation of wildlife, wilderness values, and natural undisturbed, unaltered ecosystems while allowing for recreational opportunities, including sport hunting. 16 U.S.C. 3101(a)–(b).

The legislative history of ANILCA reinforces the purpose of the National Park System units to maintain natural, undisturbed ecosystems. ''Certain units have been selected because they provide undisturbed natural laboratories—among them the Noatak, Charley, and Bremner River watersheds.'' Alaska National Interest Lands, Report of the Senate Committee on Energy and Natural Resources, Report No. 96–413 at page 137 [hereafter Senate Report]. Legislative history identifies Gates of the Artic, Denali, Katmai, and Glacier Bay National Parks as ''large sanctuaries where fish and wildlife may roam freely, developing their social structures and evolving over long periods of time as nearly as possible without the changes that extensive human activities would cause.'' Senate Report, at page 137.

The congressional designation of ''national preserves'' in Alaska was for the specific and sole purpose of allowing sport hunting and commercial trapping, unlike areas designated as national parks. 126 Cong. Rec. H10549 (Nov. 12, 1980) (Statement of Rep. Udall). 16 U.S.C. 3201 directs that national preserves shall be managed ''in the same manner as a national park . . . except that the taking of fish and wildlife for sport purposes and subsistence uses, and trapping shall be allowed in a national preserve[.]'' Under ANILCA and as used in this document, the term ''subsistence'' refers to subsistence activities by rural Alaska residents authorized by Title VIII of ANILCA, which ANILCA identifies as the priority consumptive use of fish and wildlife on public lands. 16 U.S.C. 3144. Subsistence taking of fish and wildlife in NPS areas is generally regulated by the Department of the Interior. Taking wildlife for sport purposes in national preserves is generally regulated by the State of Alaska.

In addressing wildlife harvest, the legislative history provided ''the Secretary shall manage National Park System units in Alaska to assure the optimum functioning of entire ecological systems in undisturbed natural habitats. The standard to be met in regulating the taking of fish and wildlife and trapping, is that the preeminent natural values of the Park System shall be protected in perpetuity, and shall not be jeopardized by human uses.'' 126 Cong. Rec. H10549 (Nov. 12, 1980) (Statement of Rep. Udall). This is reflected in the statutory purposes of various national preserves that were established by ANILCA, which include the protection of populations of fish and wildlife, including specific references to predators such as brown/grizzly bears and wolves.

Activities related to taking wildlife remain subject to other federal laws, including the mandate of the NPS Organic Act (54 U.S.C. 100101) ''to conserve the scenery, natural and historic objects, and wild life'' in units of the National Park System and to provide for visitor enjoyment of the same for this and future generations. Policies implementing the NPS Organic Act require the NPS to protect natural ecosystems and processes, including the natural abundances, diversities, distributions, densities, age-class distributions, populations, habitats, genetics, and behaviors of wildlife. NPS Management Policies 2006 §§ 4.1, 4.4.1, 4.4.1.2, 4.4.2. The legislative history of ANILCA reflects that Congress did not intend to modify the NPS Organic Act or its implementing policies in this respect: ''the Committee recognizes that the policies and legal authorities of the managing agencies will determine the nature and degree of management programs affecting ecological relationships, population's dynamics, and manipulations of the components of the ecosystem.'' Senate Report, at pages 232–331. NPS policy states that ''activities to reduce . . . native species for the purpose of increasing numbers of harvested species (*i.e.* predator control)'' are not allowed on lands managed by the NPS. NPS Management Policies 2006 § 4.4.3.

The State's legal framework for managing wildlife in Alaska is based on sustained yield, which is defined by State statute to mean ''the achievement and maintenance in perpetuity of the ability to support a high level of human harvest of game[.]'' AS § 16.05.255(k)(5). To that end, the Alaska Board of Game (BOG) is directed to ''adopt regulations to provide for intensive management programs to restore the abundance or productivity of identified big game prey populations as necessary to achieve human consumptive use goals[.]'' AS § 16.05.255(e). Allowances that manipulate natural systems and processes to achieve these goals, including actions to reduce or increase wildlife populations for harvest, conflict with laws and policies applicable to NPS areas that require preserving natural wildlife populations. See, *e.g.,* NPS Management Policies 2006 §§ 4.1, 4.4.3.

This potential for conflict was recognized by the Senate Committee on Energy and Natural Resources prior to the passage of ANILCA, when the Committee stated that ''[i]t is contrary to the National Park Service concept to manipulate habitat or populations to achieve maximum utilization of natural resources. Rather, the National Park System concept requires implementation of management policies which strive to maintain natural abundance, behavior, diversity and ecological integrity of native animals as part of their ecosystem, and that concept should be maintained.'' Senate Report, at page 171.

In the last several years, the State of Alaska has allowed an increasing number of liberalized methods of hunting and trapping wildlife and extended seasons to increase opportunities to harvest predator species. Predator harvest practices recently authorized on lands in the State, including lands in several national preserves, include:

• Taking any black bear, including cubs and sows with cubs, with artificial light at den sites;

• harvesting brown bears over bait (which often includes dog food, bacon/meat grease, donuts, and other human food sources); and

• taking wolves and coyotes (including pups) during the denning season when their pelts have little trophy, economic, or subsistence value.

These practices are not consistent with the NPS's implementation of ANILCA's authorization of sport hunting and trapping in national preserves. To the extent such practices are intended or reasonably likely to manipulate wildlife populations for harvest purposes or alter natural wildlife behaviors, they are not consistent with NPS management policies implementing the NPS Organic Act or the sections of ANILCA that established the national preserves in Alaska. Additional liberalizations by the State that are inconsistent with NPS management directives, policies, and federal law are anticipated in the future.

16 U.S.C. 3201 of ANILCA provides ''within national preserves the Secretary may designate zones where and periods when no hunting, fishing, trapping, or entry may be permitted for reasons of public safety, administration, floral and faunal protection, or public use and enjoyment.'' In order to comply with federal law and NPS policy, the NPS has adopted temporary restrictions under 36 CFR 13.40(e) to prevent the application of the above listed predator harvest practices to national preserves in Alaska (see, *e.g.,* 2013 Superintendent's Compendium for Denali National Park and Preserve). These restrictions protect fauna and provide for public use and enjoyment consistent with ANILCA. While the NPS prefers a State solution to these conflicts, the State has been mostly unwilling to accommodate the different management directives for NPS areas. In the last ten years, the NPS has objected to more than fifty proposals to liberalize predator harvest in areas that included national preserves, and each time the BOG has been unwilling to exclude national preserves from State regulations designed to manipulate predator/prey dynamics for human consumptive use goals.

In deciding not to treat NPS lands differently from State and other lands, the BOG suggested the NPS was responsible for ensuring that taking wildlife complies with federal laws and policies applicable to NPS areas, and that the NPS could use its own authority to ensure national preserves are managed in a manner consistent with federal law and NPS policy. See, *e.g.,* Statement of BOG Chairman Judkins to Superintendent Dudgeon, BOG Public Meeting in Fairbanks, Alaska (February 27, 2010) (NPS was testifying in opposition to allowing the take of black bear cubs and sows with cubs with artificial light in national preserves). In the absence of State action excluding national preserves, this rulemaking is required to make the temporary restrictions permanent. 36 CFR 13.50(d). This rule responds to the BOG's suggestion by promulgating NPS regulations to ensure national preserves are managed consistent with federal law and policy and prevent historically prohibited sport hunting practices from being authorized in national preserves.

The scope of this rule is limited—sport hunting and trapping are still allowed throughout national preserves and the vast majority of State hunting regulations are consistent with federal law and policy and continue to apply in national preserves. This rule only restricts sport hunting and trapping in national preserves, which constitute less than six percent of the lands in Alaska open to hunting. This rule does not limit the taking of wildlife for Title VIII subsistence uses under the federal subsistence regulations.

Final Rule

Summary of Final Rule

The rule separates regulations that govern the taking of fish and the taking of wildlife into two sections: 13.40 and 13.42, respectively. The rule makes the following substantive changes to existing NPS regulations:

(1) In accordance with NPS policies, taking wildlife, hunting or trapping activities, or management actions involving predator reduction efforts with the intent or potential to alter or manipulate natural predator-prey dynamics and associated natural ecological processes to increase harvest of ungulates by humans are not allowed on NPS-managed lands. It also explains how the NPS will notify the public of specific activities that are not consistent with this section.

(2) Affirms current State prohibitions on harvest practices by adopting them as federal regulation, and also maintains historical prohibitions on certain practices that the State has recently authorized for sport hunting of predators: (i) Taking any black bear, including cubs and sows with cubs, with artificial light at den sites; (ii) taking brown bears over bait; and (iii) taking wolves and coyotes during the denning season. The rule also eliminates exceptions to practices generally prohibited under State of Alaska law, thereby prohibiting: Taking caribou that are swimming, or from a motorboat that is under power, in two game management units (GMU); baiting black bears; and using dogs to hunt black bears.

(3) Prohibits intentionally obstructing or hindering persons actively engaged in lawful hunting or trapping.

(4) Updates and simplifies procedures for implementing closures or restrictions in park areas, including taking fish and wildlife for sport purposes.

(5) Updates NPS regulations to reflect federal assumption of the management of subsistence hunting and fishing under Title VIII of ANILCA from the State in the 1990s.

(6) Allows the use of native species as bait, commonly salmon eggs, for fishing in accordance with applicable federal and non-conflicting State law. This supersedes for park areas in Alaska the National Park System-wide prohibition on using certain types of bait in 36 CFR 2.3(d)(2).

Prohibiting Predator Reduction

Activities or management actions involving predator reduction efforts with the intent or potential to alter or manipulate natural ecosystems or processes (including natural predator/prey dynamics, distributions, densities, age-class distributions, populations, genetics, or behavior of a species) are inconsistent with the laws and policies applicable to NPS areas. The rule clarifies in regulation that these activities are not allowed on NPS lands in Alaska. Under this rule, the Regional Director will compile a list updated at least annually of activities prohibited by this section of the rule. Notice will be provided in accordance with 36 CFR 13.50(f) of this rule.

Prohibiting Methods and Means of Taking Wildlife in National Preserves

The rule codifies for national preserves current State prohibitions on harvest practices, and also maintains historical prohibitions on certain sport hunting practices that have been recently authorized by the State for taking predators. It also eliminates exceptions (as applied to national preserves) under State laws that authorize sport hunters to take swimming caribou, to take caribou from motorboats under power, to take black bears over bait, and to use dogs to hunt black bears. The elements of the rule that are described in this paragraph will not be implemented until January 1, 2016, to avoid any potential confusion that may arise from issuing this rule during the 2015 hunting seasons. Delaying the implementation of these provisions will give the general public and other stakeholders sufficient time to understand the new rules before the 2016 hunting seasons begin.

Prohibiting the Obstruction of Persons Engaged in Lawful Hunting or Trapping

The rule prohibits the intentional obstruction or hindrance of another person's lawful hunting or trapping activities. This includes (i) placing oneself in a location in which human presence may alter the behavior of the game that another person is attempting to take or alter the imminent feasibility of taking game by another person; or (ii) creating a visual, aural, olfactory, or physical stimulus in order to alter the behavior of the game that another person is attempting to take. These actions are prohibited by State law, but this law is not adopted under the regulations for national preserves, because it does not directly regulate hunting and trapping. This rule directly codifies these prohibitions into the NPS regulations, to prevent the frustration of lawful hunting and trapping in national preserves.

Updating Closure and Restriction Procedures

The rule updates and simplies the procedures for implementing closures and restrictions on certain activities in NPS areas in Alaska. These changes will make the procedures in Alaska more consistent with other NPS units outside of Alaska and with Alaska State Parks. The rule clarifies that Superintendents must use the procedures in § 13.50 to implement any closure or restriction in NPS areas in Alaska. This eliminates potential confusion about whether the procedures in § 13.50 apply only when they are referenced in a separate regulation in part 13 (currently found in the regulations for weapons, camping, and taking fish and wildlife), or whether they apply to all closures and restrictions in Alaska.

The rule requires rulemaking for nonemergency closures or restrictions if the closures or restrictions (or the termination or relaxation of them) are of a nature, magnitude and duration that will result in a significant alteration in the public use pattern of the area, adversely affect the area's natural, aesthetic, scenic or cultural values, or require a long-term or significant modification in the resource management objectives of the area. These rulemaking criteria are modeled after the the criteria that apply to closures and restrictions in Alaska State Parks (11 AAC 12.335), which are also similar to the criteria in 36 CFR 1.5(b) that apply to NPS areas outside of Alaska. Emergency closures and restrictions are limited to the duration of the emergency.

Before a nonemergency closure or restriction can be implemented, the NPS must issue a written determination explaining the basis of the closure or restriction. The NPS will also compile in writing a list, updated annually, of all closures and restrictions (*i.e.,* the compendium). The compendium and the written determinations of need will be posted on the NPS Web site and made available at park headquarters.

With respect to nonemergency restrictions on taking of fish and wildlife in national preserves, the final rule requires an opportunity for public comment, including a public meeting near the affected NPS unit, before the action is taken. This rule recognizes that, although the internet has become an effective method of communicating with the public, in-person public meetings may still be the most effective way to engage Alaskans, particularly those in rural areas. The rule also requires the NPS to consult with the State prior to adopting such closures and restrictions. Emergency closures or restrictions on the taking of fish or wildlife are limited to 60 days and may only be extended after consultation with the State and an opportunity for public comment, including a public meeting, near the affected NPS unit.

The following table summarizes the changes from the proposed rule regarding procedures to implement closures or restrictions in § 13.50:

Proposed rule procedures	Final rule procedures
Applicability	
Applies only to closures pertaining to weapons, camping, and taking of fish or wildlife.	Applies to all closures or restrictions except when more specific procedures apply in 36 CFR part 13.
Factors used to determine whether to close an area or restrict an activity	
Includes protecting the integrity of naturally-functioning ecosystems as an appropriate reason for a closure or restriction.	Retains factors in existing regulations at 13.50.
Written determinations	
Not required	Requires a written determination explaining the reason for the proposed closure/restriction in nonemergency situations. This determination will be posted on *www.nps.gov.*
Emergency Closures or Restrictions	
May not exceed 60 days	Duration of the emergency, except for emergency closures or restrictions on taking fish or wildlife, which may not exceed 60 days.
Restrictions on Taking Fish or Wildlife (nonemergency)	
Consultation with the State and opportunity for public comment prior to adopting a closure or restriction.	Consultation with the State and opportunity for public comment, including one or more public meetings near the affected NPS unit, prior to implementing a closure or restriction.
Notice	
Closures or restrictions will be effective upon publication on park website.	Some closures or restrictions will be effective upon publication on park websites, but other closures or restrictions may be posted on a park website prior to taking effect, to give the public adequate time to understand and comply with them. A list of closures and restrictions will be compiled in writing and updated annually, and will be posted on the park websites.

Update Subsistence Regulations to Reflect Federal Management

The rule updates the subsistence provisions in NPS regulations (36 CFR 13.470, 13.480, and 13.490) to reflect the federal government's assumption of the management and regulation of subsistence take of fish and wildlife under ANILCA and the transfer of subsistence management under Title VIII from the State to the Federal Subsistence Board. The rule makes other non-substantive, editorial changes to the language in 36 CFR 13.490 to streamline, clarify, and better organize this section.

Allowing the Use of Native Species as Bait for Fishing

NPS regulations generally prohibit the use of many forms of bait for fishing to help protect against the spread of nonnative species. Fish eggs from native species (usually salmon), are commonly used for fishing in Alaska. This rule allows the use of local native species as bait for fishing.

Frequently Asked Questions

This section explains some of the principal elements of the rule in a question and answer format.

Why is this rule necessary?

The rule responds to State hunting regulations that authorize wildlife harvest practices that conflict with ANILCA's authorization for sport hunting, the statutory purposes for which national preserves were established, and the NPS Organic Act as implemented by the NPS. These include liberalized predator harvest seasons, bear baiting, and the harvest of caribou while swimming. National park areas are managed for natural ecosystems and processes, including wildlife populations. The NPS legal and policy framework prohibits reducing native predators for the purpose of increasing numbers of harvested species.

As discussed above, the rule also responds to a number of other regulatory needs, by updating and streamlining closure procedures, updating subsistence provisions to reflect the program's actual management, prohibiting interference with lawful hunting consistent with State law, and allowing use of native species as bait for fishing.

Does this rule restrict subsistence harvest of wildlife under Title VIII of ANILCA?

No.

Does this rule prohibit all hunting under State regulations on national preserves in Alaska?

No. This rule restricts certain methods of harvest currently allowed on national preserves by the State of Alaska under its general hunting regulations. These include the taking of any black bear, including cubs and sows with cubs, with artificial light at den sites, taking brown and black bears over bait, taking wolves and coyotes between May 1 and August 9, harvest of swimming caribou or taking caribou from a motorboat while under power, and using dogs to hunt black bears. Additionally, State laws or regulations involving predator reduction efforts with the intent or potential to alter or manipulate natural predator-prey dynamics and associated natural ecological processes to increase harvest of ungulates by humans will not apply in national preserves, pursuant to this rule. These restrictions will affect a very small percentage of hunting practices authorized by State regulation and less than six percent of the lands in Alaska that are open to hunting.

What regulations apply to hunting and trapping in national preserves?

Title 36 of the Code of Federal Regulations (CFR) applies to sport hunting and trapping in national preserves. State harvest laws and regulations (Alaska Statute Title 16 and Alaska Administrative Code Title 5 AAC) that are consistent with 36 CFR also apply on national preserves. ANILCA Title VIII subsistence harvest of fish and wildlife by Federally-qualified rural residents is authorized in national preserves in Alaska under 36 CFR part 13 and 50 CFR part 100. Please contact the park chief ranger for additional information or assistance.

Do I still have to use the State regulations book when hunting on national preserves?

Yes. State hunting regulations apply to national preserves except when in conflict with federal regulation. Please contact the park chief ranger for additional information or assistance.

Does this rule restrict intensive management of predators on NPS lands?

Yes. Consistent with NPS Management Policies 2006, the NPS Organic Act, and the statutory purposes for which national preserves were established, this rule prohibits predator reduction activities on national preserves that have the intent or potential to alter or manipulate natural predator-prey dynamics and associated natural ecological processes to increase harvest of ungulates by humans.

What is the authority for the NPS to restrict hunting and trapping in this rule?

The NPS Organic Act authorizes the NPS to promulgate regulations that are necessary and proper for the use and management of National Park System units, including national preserves in Alaska, for the purpose of conserving the wild life and providing for the enjoyment of the wild life in such manner and by such means as will leave them unimpaired for the enjoyment of future generations. 54 U.S.C. 100101(a) and 100751. ANILCA authorizes the Secretary of the Interior, acting through the NPS, to promulgate regulations prescribing restrictions relating to hunting, fishing, or trapping for reasons of public safety, administration, floral and faunal protection, or public use and enjoyment. 16 U.S.C. 3201 and 3202.

The rule says that State laws or management actions involving predator reduction are not adopted in national preserves. How will I know if a State law involves predator reduction?

The Regional Director will compile a list updated at least annually of State laws and regulations that are not adopted in national preserves. This list will be posted at *www.nps.gov* and available upon request at NPS park headquarters.

I live in a nonrural area and hunt under State subsistence regulations. Does this rule restrict my subsistence harvest practices?

Title VIII of ANILCA limits subsistence activities to local rural residents. This rule does not restrict federally-qualified subsistence users who are hunting in accordance with federal subsistence regulations. But those persons living in nonrural areas (who therefore are not federally-qualified subsistence users) must comply with the restrictions in this rule. For example, only federally qualified subsistence users hunting under federal subsistence regulations will be able to take swimming caribou within national preserves, for all others this practice will now be prohibited in national preserves.

How is hunting on national preserves different than hunting on State land?

Hunting in national preserves is different than on State (or private) lands because NPS regulations also apply and govern in the event of a conflict with State law or regulation. However, harvest opportunities and practices in national preserves vary little from practices allowed under State law, except for some very specific circumstances for which where the NPS has issued regulations. For example, same-day airborne hunting of big game animals, arctic fox, red fox, and lynx has not been allowed on NPS lands since 1995. This rule adds several additional NPS regulations prohibiting the following harvest practices that are allowed under State law: (1) Taking any black bear, including cubs and sows with cubs, with artificial light at den sites, (2) taking brown bears and black bears over bait, (3) taking wolves and coyotes from May 1 through August 9, (4) harvest of swimming caribou and harvest of caribou from a moving motorboat by those other than local rural residents in those portions of Noatak, Gates of the Arctic, and Bering Land Bridge Preserves that are within GMUs 23 and 26, and (5) using dogs to hunt black bears.

Black bear baiting has been allowed for more than three decades. Why is the NPS prohibiting it now?

The NPS proposed prohibiting the harvest of brown bears over bait to avoid public safety issues, to avoid food-conditioning bears and other species, and to maintain natural bear behavior as required by NPS law and policy. Other land and wildlife management agencies strive to eliminate the feeding of bears through individual and collective educational efforts due to the increased likelihood that food-conditioned bears will be killed by agency personnel or the public in defense of life or property. Food-conditioned bears are also believed more likely to cause human injury. Baiting tends to occur in accessible areas used by multiple user groups, which contributes to the public safety concerns associated with baiting. The concerns presented with taking brown bears over bait also apply to black bear baiting. After reviewing public comment, the final rule prohibits taking both black bears and brown bears over bait in national preserves.

Why is the NPS prohibiting the take of swimming caribou by individuals who are not federally qualified subsistence users?

Taking swimming big game is already generally prohibited by State law, but there are exceptions in State law for the take of swimming caribou in GMUs 23 and 26, which include portions of Noatak, Bering Land Bridge, and Gates of the Arctic National Preserves. This method of harvest remains available to federally qualified subsistence users in their pursuit of food. However, as is further explained below, this method is one of those that NPS has found is not consistent with ANILCA's authorization for sport hunting in national preserves.

Does this rule impact fishing in NPS units in Alaska?

Yes. This rule allows federally qualified subsistence users to use native species as bait for fishing in accordance with federal subsistence regulations.

Others will also be able to use native species for bait when such use is in accordance with non-conflicting State fishing regulations.

What procedures must the NPS follow to adopt closures and restrictions in NPS units in Alaska?

The procedures in 36 CFR 13.50 apply to all closures and restrictions in NPS units in Alaska, unless there are more specific procedures stated elsewhere in law or regulation. For example, the following regulations have specific procedures:

- Unattended or abandoned property, 36 CFR 13.45
- Use of snowmobiles, motorboats, dog teams, and other means of surface transportation traditionally employed by local rural residents engaged in subsistence uses, 36 CFR 13.460
- Subsistence use of timber and plant material, 36 CFR 13.485
- Closure to subsistence uses of fish and wildlife, 36 CFR 13.490

What closures or restrictions will require notice and comment rulemaking that is published in the ***Federal Register****?*

Any nonemergency closure or restriction, or the termination or relaxation of such, which is of a nature, magnitude, and duration that will result in a significant alteration in the public use pattern of the area; adversely affect the area's natural, aesthetic, scenic, or cultural values; or require a long-term modification in the resource management objectives of the area.

Doesn't ANILCA require public hearings prior to adopting closures or restrictions?

Public hearings near the affected vicinity are required before restricting: (1) Subsistence harvest of fish or wildlife under Title VIII of ANILCA or (2) access authorized under 16 U.S.C. 3170 (a) of ANILCA. There is no statutory requirement for a public hearing for other types of closures or restrictions.

Did the NPS eliminate a requirement for public hearings in the affected areas before adopting closures or restrictions relating to the take of fish and wildlife?

The proposed rule included a requirement to provide an opportunity for public comment on potential restrictions to taking fish or wildlife. Public comment may include written comments, a public meeting, a public hearing, or a combination thereof. Based upon public comment and to be more consistent with the practices of the BOG and the Federal Subsistence Board, the NPS modified the proposed rule to provide that the opportunity for comment must include at least one public meeting near the affected NPS unit in nonemergency situations. This is a change from the existing regulations, which require a public hearing. Requiring a ''meeting'' instead of a ''hearing'' provides more flexibility on how the event is structured. During the public hearings conducted in 2014, the NPS received feedback that some local communities prefer a less formal approach and more opportunities for dialog with NPS managers. The NPS believes the term ''meeting'' more appropriately describes this type of informational exchange. The NPS also believes the term public meeting is broad enough to include a public hearing if that is more appropriate for the area.

Where can I find information about closures and restrictions?

Information about closures and restrictions is posted on each park's Web site at *www.nps.gov*. This information is also available upon request at NPS park headquarters.

Why did the NPS delete the references to State law in the subsistence regulations?

The NPS deleted the provisions adopting non-conflicting State law because the State no longer manages subsistence harvest under Title VIII of ANILCA. Subsistence harvest of fish and wildlife on federal public lands is generally regulated by the Federal Subsistence Board.

Is the NPS required to consult with the State prior to adopting closures or restrictions to taking fish or wildlife?

Yes, except in the case of emergencies.

Is the NPS required to consult with tribes and ANCSA Native Corporations?

Yes, the NPS is required to consult with tribes if an NPS action would have a substantial direct effect on federally recognized Indian tribes. Consultation with ANCSA Native Corporations is required if an NPS action would have a substantial direct effect on ANCSA Native Corporation lands, waters, or interests.

Is the NPS required to consult with affected user groups, such as Regional Advisory Committees, Subsistence Resource Commissions, hunting organizations, or other nongovernmental organizations?

While this kind of consultation is not required by law, the NPS regards the input from these advisory and other groups as invaluable. The NPS encourages these groups to engage with park managers on topics of interest. The NPS also invites and encourages these committees and groups to provide input on decisions affecting public use of NPS managed lands as outlined in this final rule.

Summary of and Responses to Public Comments

A summary of substantive comments and NPS responses is provided below followed by a table that sets out changes we have made to the proposed rule based on the analysis of the comments and other considerations.

Consultation

1. Comment: Some commenters stated the NPS did not adequately consult with the State of Alaska prior to publishing the proposed rule and in doing so, acted inconsistently with ANILCA, the Master Memorandum of Understanding between the NPS and the Alaska Department of Fish and Game (ADF&G), and Executive Order 12866.

NPS Response: The NPS respects its responsibility to consult with the State (and others) regarding NPS actions, especially given that wildlife management in NPS units is a responsibility that is shared between the NPS and the State. Publication of the proposed rule provided an opportunity for consultation between the NPS and the State. The NPS and the ADF&G met shortly after the publication of the proposed rule, which is consistent with ANILCA's consultation requirement. 16 U.S.C. 3201. The NPS has engaged in ongoing communications with the ADF&G, the BOG, the State of Alaska ANILCA Implementation Program, and the State of Alaska Citizen's Advisory Commission on Federal Areas for a number of years regarding the issues that this rule addresses.

Executive Order 12866 requires federal agencies to ''seek views of appropriate State, local, and tribal governments before imposing regulatory requirements that might significantly or uniquely affect those governmental entities.'' Sec. 1(b)(9). As discussed below, the Office of Management and Budget determined this rule is not a significant regulatory action subject to this requirement. Regardless, the NPS invited the views of State, local, and tribal governments before publishing this final rule, and also complied with its responsibilities under section 4 of the Executive Order by including the proposed rule in the Unified Regulatory Agenda that was published by the Office of Management and Budget on reginfo.gov.

The NPS signed and implemented the Master Memorandum of Understanding (MMOU) with the ADF&G in 1982. The MMOU states that the ADF&G will manage wildlife on NPS managed lands for natural species diversity and natural process. The NPS agreed to recognize ADF&G as having the primary responsibility to manage wildlife on lands in the State and utilize the State's regulatory process to the maximum extent possible. Both agencies agreed to coordinate planning to minimize conflicts from differing legal mandates and consult with each other when developing regulations. The NPS continues to recognize the State as having primary responsibility to manage fish and wildlife on lands in the State. However, the State's responsibility is not exclusive and it does not preclude federal regulation of wildlife on federal public lands, as is well-established in the courts and specifically stated in ANILCA. The NPS also attempted to utilize the State regulatory process to notify the BOG when proposals created a conflict with NPS laws, regulations, and policies, years before the publication of the proposed rule. During this time NPS requested that the conflicts be resolved, as a first resort, through the State regulatory process. Only after conflicts could not be resolved through that process, and the BOG suggested the NPS could use its own authority to meet is mandates for managing wildlife, did the NPS consider modifications to federal regulations to resolve the conflicts.

2. Comment: Some commenters stated that the NPS did not adequately consult with tribes, various advisory committees, and rural residents prior to publishing the proposed rule.

NPS Response: NPS has an obligation to consult with tribes prior to making a decision that would have a substantial direct effect on federally-recognized tribes. Even though the NPS determined that the proposed rule would not have a substantial direct effect on tribes, the NPS initiated consultation shortly after publication of the proposed rule. The NPS emailed a letter to tribes inviting them to consult and notifying them of two statewide conference calls dedicated to tribal consultation in the fall of 2014. No one provided comments or asked questions during the first call. On the second call, four individuals who serve as members of tribal councils provided comments. Park managers also contacted tribes with ties to the park areas by phone, email, and letter to invite them to consult. NPS met in person with three tribes that requested additional consultation. The NPS also provided information to affected Subsistence Resource Commissions and Regional Advisory Councils beginning when the first temporary wildlife harvest restrictions were considered in 2010, and provided periodic updates throughout the process. Since these harvest restrictions were first proposed, the NPS stated its intention to initiate rulemaking and solicited public comment on these provisions. After the proposed rule was published, the NPS provided 121 days for written comment, met with and provided information to multiple groups, and held an additional 26 public hearings across the State, in rural locations near affected units as well as Anchorage, Fairbanks, Palmer, and Soldotna.

3. Comment: Some commenters stated the NPS did not respond to comments and questions from the State of Alaska on the temporary wildlife harvest restrictions that were included in the proposed rule, which might have enabled the State to take action that would make the proposed harvest restrictions unnecessary. Commenters also suggested the NPS work with the State of Alaska collaboratively to address the wildlife harvest issues in this rule.

NPS Response: The NPS would have preferred a collaborative approach with a solution in State law or regulation rather than federal regulation. To that end, the NPS has testified before the Board of Game many times, requested the Board of Game take specific regulatory action to address NPS concerns, met with ADF&G, provided explanations for the restrictions in writing, and responded to comments in the annual park compendiums. The NPS acknowledges the State requested scientific data to support the temporary restrictions on taking black bears, including cubs and sows with cubs, with artificial light at den sites, taking brown bears over bait, and prohibiting the take of wolves and coyotes during the summer months. However, neither the temporary restrictions nor this rule are based on particular wildlife population levels, and do not require the preparation of such scientific data. The basis of the compendium provisions, as well as the rule, is the NPS legal and policy framework, which has been communicated verbally and in writing several times.

Process for Publishing the Proposed Rule

4. Comment: Several comments stated that the NPS should give more weight to comments on the proposed rule from Alaskans than other members of the public. Another comment urged the NPS to increase cooperation and dialogue with rural Alaskans. Others expressed concern that the NPS is not considering public comments when developing the final rule, and did not adequately respond to public comments delivered at public meetings.

NPS Response: The NPS agrees that it will continue to strive to increase cooperation and dialogue with rural Alaskans, many of whom live near the national preserves and may be affected by this rule. After consideration of public comments on the proposed rule, the NPS has included a provision in the final rule requiring it hold one or more public meetings near the affected NPS unit before implementing any non-emergency closure or restriction on the sport take of fish or wildlife in national preserves.

During the comment periods for the proposed rule, the NPS held 26 public hearings in Alaska in an effort to solicit the opinions and comments of Alaskans. The NPS has considered all relevant comments it received on the proposed rule, including those from rural Alaskans and those delivered at public meetings. The NPS considers each comment based upon its substantive content, and does not give greater weight to any comment based upon the residence of the commenter. This is also consistent with the statutory purpose for establishing the national preserves in Alaska for the benefit, use, education, and inspiration of present and future generations of all Americans.

5. Comment: Some comments stated that the NPS did not provide the public with sufficient time to review and comment on the proposed rule. Other comments felt that the NPS should not be allowed to make changes to the proposed rule without allowing the public to review and comment on those changes.

NPS Response: The policy of the U.S. Department of the Interior is ordinarily to provide at least 60 days for public comment on any proposed rule that is published in the **Federal Register**. Due to the anticipated interest in this rule, the NPS provided an initial comment period of 90 days so that the public would have additional time to consider the proposal and submit timely comments. After the initial 90-day comment period expired, the NPS received several requests to reopen the comment period to give the public more time to review and prepare comments. Acknowledging the interest in this rule, the NPS agreed with these requests and reopened the comment period for an additional 31 days. In total, the NPS provided the public with 121 days to review and comment on the proposed rule, and appreciates the thoughtful consideration and responses it received. The NPS believes that the length of the combined public comment period was adequate and does not intend to reopen, for a second time, the public comment period.

After considering public comments and after additional review, the NPS made certain changes to the proposed rule, which are described in the section below entitled ''Changes from the Proposed Rule.'' The changes are a logical outgrowth of the proposed rule, and were reasonably foreseeable by the public when the proposed rule was published. For example, the NPS specifically requested comment on taking black bears over bait in the proposed rule. This notified the public that the proposed rule could change with respect to this issue after consideration of public comment. Other changes to the proposed rule, such as requiring a public meeting before adopting a closure or restriction for taking wildlife, are consistent with the existing regulations at 36 CFR 13.50.

Comments on Guiding Laws and Regulations

6. Comment: Some commenters stated that NPS does not have the authority to supersede State wildlife regulations, while others requested the NPS clarify its authority to preempt conflicting State regulations under the Property and Supremacy Clauses of the Constitution.

NPS Response: Under the Property and Supremacy Clauses of the U.S. Constitution, State wildlife laws that conflict with NPS's efforts to carry out its statutory mandate are preempted. *See, e.g. Kleppe* v. *New Mexico,* 426 U.S. 529 (1976); *Hunt* v. *United States,* 278 U.S. 96 (1928); *New Mexico State Game Comm'n* v. *Udall,* 410 F.2d 1197 (10th Cir.), *cert. denied, New Mexico State Game Comm'n* v. *Hickel,* 396 U.S. 961 (1969); *United States* v. *Brown,* 552 F.2d 817 (8th Cir. 1977). Certain State-authorized hunting and trapping practices are not consistent with the NPS implementation of the NPS Organic Act and ANILCA. Consequently, the final rule is an appropriate exercise of the authority affirmed by the cases cited above.

7. Comment: Several commenters questioned how any take of wildlife on national preserve lands is permissible when regulations that may ''alter the natural predator/prey dynamics, distribution, densities, age-class distributions, populations, genetics or behavior of a species'' are interpreted as being incompatible with the laws and policies of the National Park Service.

NPS Response: ANILCA provides for harvest of wildlife in national preserves. Therefore some level of take is appropriate and compatible with the NPS legal and policy framework for Alaska national preserves. This rule does not prohibit all State-authorized hunting and trapping. The vast majority of State regulations are, and are expected to remain, compatible with the NPS management framework. Over the past several decades, only a handful of State regulations have been superseded by NPS regulations.

The NPS believes that the standard in the rule is a workable and limited standard that satisfies our legal and policy framework and does not include all actions that result in the harvest of wildlife. This rule provides that the NPS does not adopt State management actions or laws or regulations that authorize taking of wildlife, which are related to predator reduction efforts, meaning that they have the intent or potential to alter or manipulate natural predator-prey dynamics and associated natural ecological processes, in order to increase harvest of ungulates by humans. The NPS acknowledges that the public would benefit from greater clarity as to exactly which State laws and regulations are not adopted by the NPS. As a result, the rule requires the Regional Director to publish at least annually a list of all such laws and regulations not adopted in national preserves.

General Comments

8. Comment: Some commenters objected to the NPS description that some of the harvest practices, such as taking swimming caribou and hunting caribou from a motorboat while under power, are ''longstanding prohibited.''

NPS Response: The harvest methods prohibited by this rule stem from general hunting and trapping restrictions in State law and regulation, some of which have been relaxed in recent years in response to proposals to the BOG. Some of these proposals to relax hunting and trapping restrictions were adopted in whole or in part to reduce predators. Three of these proposals removed longstanding prohibitions on harvest methods. In response, the NPS prohibited these methods on a temporary basis: (1) Taking any black bear, including cubs and sows with cubs, with artificial light at den sites; (2) taking brown bears over bait; and (3) taking wolves and coyotes during the summer months. This rule makes the temporary restrictions permanent. This rule also prohibits some additional practices that the NPS acknowledges were not historically prohibited. These practices, however, existed only as exceptions to general prohibitions in State law: (1) Taking swimming caribou or taking caribou from a motorboat while under power, in GMUs 23 and 26; (2) black bear baiting; and (3) using dogs to hunt black bears. For the reasons explained herein, NPS believes these practices should also now be prohibited in national preserves.

9. Comment: Some comments stated that the hunting methods that would be prohibited by the proposed rule were not intended to reduce predators but were allowed by the BOG based on requests from the Alaskans for additional harvest opportunity or to authorize traditional practices. Other comments stated the NPS proposed rule would prefer predators over ungulates. Others supported the proposed rule because it would prohibit harvest practices designed to reduce predators, which is inconsistent with NPS laws.

NPS Response: The NPS acknowledges many of the harvest practices recently authorized by the State were based in whole or in part on proposals from Alaskan hunters, some of whom may also be federally-qualified subsistence users. However, the record shows some of these proposals and the decisions to act on them were based wholly or in part on a desire to reduce predator populations, and often far in excess of any previous authorizations. Before the BOG authorized taking cubs and sows with cubs at den sites, it had only allowed this activity as part of a predator control program. (Findings of the Alaska Board of Game 2012–194–BOG, Board of Game Bear Conservation, Harvest, and Management Policy, expiration June 30, 2016 (January 18, 2012)). The State's decision to expand wolf and coyote seasons was based in part on a desire to elevate survival rates of moose and caribou calves.

As explained in the background section of this rule, NPS management policies prohibit the manipulation of wildlife populations, and require the NPS to protect natural abundances, distributions, densities, and populations of wildlife. This rule does not favor predators over ungulates, which would also violate NPS management policies. The rule is primarily focused on the take of predators because the allowances implemented by the State target predators, not ungulates. Even in these circumstances, the rule is consistent with NPS policy to allow for the fluctuation of natural populations of all species in national preserves, by prohibiting the purposeful decrease of predator populations to achieve (or attempt) an increase of ungulate populations to benefit hunters.

10. Comment: One commenter stated the NPS misinterpreted the State sustained yield mandate in the proposed rule and requested the NPS clarify the State's statutory definition to make it clear the State has authority to manage for a variety of beneficial uses of wildlife rather than only to support a high level of human harvest of wildlife.

NPS Response: NPS acknowledges that the State may have broader authorities and goals, but in general, interpretation and clarification of State law is a matter for the State. This rule ensures that taking of wildlife in national preserves is consistent with federal laws and NPS policies that require the NPS to manage national preserves for natural processes.

11. Comment: Several commenters directly or indirectly commented on State-authorized subsistence harvest of fish and wildlife. Some commenters suggested ANILCA authorizes State subsistence separate from Title VIII subsistence. Some comments stated the proposed rule restricts subsistence uses by Alaska Natives. Some commenters stated that federally qualified subsistence users often prefer to harvest wildlife under State regulations because the State regulations are more liberal than federal subsistence regulations and the Federal Subsistence Board regulatory process is cumbersome and takes too long. Conversely, some subsistence hunters voiced support for the proposed regulations as they do not consider some of the methods prohibited by this rule to be traditional or consistent with natural processes and population dynamics.

NPS Response: ANILCA, 16 U.S.C. 3201, states that national preserves shall be managed ''in the same manner as a national park . . . except that the taking of fish and wildlife for sport purposes and subsistence uses, and trapping shall be allowed in a national preserve[.]'' Under ANILCA and in this rule, the term ''subsistence'' refers only to subsistence activities authorized by Title VIII of ANILCA, which must comply with the federal subsistence regulations (among other things, they are restricted to rural Alaska residents). ANILCA did not authorize any separate State subsistence activities. Take of wildlife is authorized in national preserves only to the extent it is consistent with either the federal subsistence regulations or with regulations applicable to taking of wildlife for ''sport purposes.''

The NPS acknowledges that some rural residents eligible to harvest wildlife under federal subsistence regulations in NPS units also harvest wildlife under State regulations in national preserves, particularly when the State methods, seasons, and bag limits are more liberal. To the extent that this harvest does not conflict with NPS regulations applicable to sport hunting, these opportunities are preserved. Any changes to federal subsistence regulations should be proposed to the Federal Subsistence Board.

12. Comment: Some commenters objected to the use of the term ''sport hunting'' in the proposed rule as offensive and inaccurate in certain cases such as when a federal subsistence user moves out of the area and is no longer eligible to harvest under federal subsistence regulations.

NPS Response: The NPS understands that some hunters who harvest wildlife under State regulations are not hunting for recreation or ''sport.'' Sometimes individuals who are harvesting under State regulations were once rural residents but are no longer federally qualified subsistence users. However, Congress used the term ''sport purposes'' in ANILCA and it would be inappropriate for the NPS to allow harvest that is neither for ''subsistence purposes'' nor for ''sport purposes'' under 16 U.S.C. 3201.

13. Comment: Some commenters supported the prohibition on the methods of take in the proposed rule because they are unsporting or unethical; others stated the NPS should not regulate ethics regarding wildlife harvest.

NPS Response: Although the term ''sport'' is not defined in ANILCA, each term in a statute is presumed to have meaning. Sportsmanship in hunting has more than a hundred years of tradition and meaning in the conservation movement in America. See John F. Reiger, American Sportsmen and the Origin of Conservation (Winchester Press 1975). When methods of harvest go beyond traditionally accepted norms of ''sport'' in hunting, they may fall outside of what Congress intended when it authorized hunting in statutes like ANILCA. In some such cases, NPS believes regulations may be needed to curtail these activities that were never intended to occur in units of the National Park System. Such situations historically have been rare. Except for the prohibition of same-day airborne hunting in 1995, the NPS has not restricted the practices authorized by the State through federal rulemaking published in the CFR. There has, however, been a departure in recent years by the BOG, which has sought to advance the goals of increasing harvested species by targeting predators. In order to comply with federal law and NPS policy, these recent allowances have been prohibited by the NPS in national preserves on a temporary basis through compendium actions, and are now permanently prohibited by this rule.

The NPS also recognizes that some practices that are being prohibited for ''sport'' hunters may be appropriate for subsistence users. An example of this is taking swimming caribou. On NPS lands, the take of swimming caribou for subsistence is allowed in accordance with federal subsistence regulations, but it is not appropriate as a ''sport'' hunting practice on waters within national preserves.

14. Comment: Some commenters stated the proposed rule would prohibit Alaska residents from participating in State subsistence fisheries.

NPS Response: This rule makes no changes to fishing regulations other than allowing the use of native species as bait for fishing. Fishing in NPS units under federal subsistence regulations must be in accordance with 36 CFR 13.470 and 50 CFR part 100. Other noncommercial fishing is authorized under 36 CFR 13.40 and in accordance with the provisions of 36 CFR 2.3. To the extent it is consistent with those regulations, State-authorized subsistence fishing is allowed within NPS units.

15. Comment: Some commenters asserted that NPS does not have authority to enact the proposed regulations and that the NPS actions are inconsistent with 16 U.S.C. 3114 and 16 U.S.C. 3125(3) of ANILCA.

NPS Response: This final rule is not promulgated under 16 U.S.C. 3114, which provides that subsistence take of fish and wildlife has priority over other uses when it is necessary to restrict the harvest of fish or wildlife to protect the viability of the population or to continue subsistence uses. The restrictions in this rule are not necessary to protect the viability of a population or to continue Title VIII subsistence uses, nor do they affect subsistence uses or priority. The NPS is promulgating this rule under the NPS Organic Act and 16 U.S.C. 3201, which provide NPS with authority to restrict the taking of wildlife for sport purposes in national preserves for reasons of public safety, administration, floral and faunal protection, or public use and enjoyment.

Similarly, 16 U.S.C. 3125(3) does not apply to this rule. That provision provides that ''[n]othing in this title shall be construed as . . . authorizing a restriction on the taking of fish and wildlife for nonsubsistence uses . . . unless necessary for the conservation of healthy populations of fish and wildlife . . . to continue subsistence uses of such populations [.]'' The phrase ''this title'' refers solely to Title VIII of ANILCA—this section does not apply to 16 U.S.C. 3201, which was enacted as part of Title XIII. This section thus does not preclude the NPS from authorizing restrictions under other titles in ANILCA (such as Title XIII) or other federal laws (such as the NPS Organic Act), as is the case here.

16. Comment: Some commenters stated the NPS should limit hunting to traditional harvest methods because current technology could result in overharvest. Commenters also stated that resources should be allocated to most local users when harvest must be reduced.

NPS Response: In consultation with the State and the Federal Subsistence Board, the NPS will consider restrictions on specific harvest practices on a case by case basis. In times of shortage ANILCA, 16 U.S.C. 3114, provides priority to local subsistence users over others.

17. Comment: Some commenters objected to the statement in the proposed rule that management of wildlife on national preserves must protect natural processes, because ANILCA calls for ''healthy'' populations, not ''natural'' populations.

NPS Response: Title VIII of ANILCA refers to conserving ''healthy'' populations of wildlife on federal public lands in Alaska. ANILCA also states that nothing in the statute modifies or repeals any federal law governing the conservation or protection of fish and wildlife. The statute explicitly identifies the NPS Organic Act as one of those federal laws. The NPS Organic Act requires the NPS to conserve the wild life in units of the National Park System (including national preserves) and to provide for visitor enjoyment of the wild life for this and future generations. 54 U.S.C. 100101. Policies implementing the NPS Organic Act require the NPS to protect natural ecosystems and processes, including the natural abundances, diversities, distributions, densities, age-class distributions, populations, habitats, genetics, and behaviors of wildlife. NPS Management Policies 2006 §§ 4.1, 4.4.1, 4.4.1.2, 4.4.2. The legislative history of ANILCA reflects that Congress did not intend to modify the NPS Organic Act in this respect: ''the Committee recognizes that the policies and legal authorities of the managing agencies will determine the nature and degree of management programs affecting ecological relationships, population's dynamics, and manipulations of the components of the ecosystem.'' Senate Report 96–413, Committee on Energy and Natural Resources at pages 232–233 (hereafter Senate Report 96–413). This is reflected in the statutory purposes of various national preserves that were established by ANILCA, which include the protection of populations of fish and wildlife.

18. Comment: Some commenters stated the proposed rule includes ambiguous terms and gives too much discretion to park superintendents.

NPS Response: The NPS believes the actions the superintendents are authorized to take in the rule are consistent with federal law and are comparable to the actions superintendents have long been authorized to take in similar circumstances. It also recognizes that superintendents are the subject matter experts regarding management of the park unit and have been delegated responsibility to take action and respond to changing circumstances that may affect the values and resources of a park unit.

19. Comment: Some commenters questioned the basis of the proposed rule because the NPS did not cite or provide evidence or data related to wildlife population-level effects or any conservation concern.

NPS Response: As discussed above, the rule is based on the NPS legal and policy framework, which among other things ''requires implementation of management policies which strive to maintain natural abundance, behavior, diversity and ecological integrity of native animals as part of their ecosystem . . . .'' Senate Report 96–413, at page 171. This rule is not based on particular wildlife population levels, and did not require the preparation of data on those levels. Rather the rule reflects the NPS responsibility to manage national preserves for natural processes, including predator-prey relationships, and responds to practices that are intended to alter those processes.

20. Comment: A couple of commenters asked for clarification about the harvest opportunities that would be prohibited by the proposed rule on a unit by unit basis.

NPS Response: The NPS believes the rule clearly describes the harvest practices that are prohibited. All but three of these practices are already prohibited by either NPS temporary actions or existing State law. The only currently allowed harvest practices that will be prohibited under this rule are taking caribou that are swimming or taking caribou from a motorboat while under power (currently allowed in portions of Noatak, Gates of the Arctic, and Bering Land Bridge National Preserves), black bear baiting, and using dogs to hunt black bears. The NPS will assist the public to understand the impacts of the rule on sport harvest of wildlife in national preserves. The public and visitors are encouraged to contact or visit the local NPS offices for information or assistance.

21. Comment: One commenter opposed the prohibition on the take of muskrats at pushups, adding that this practice has been authorized by the State since 1967 and that the practice is not known to have caused conservation or user problems.

NPS Response: The proposed rule would have prohibited the take of muskrats at pushups, which is currently authorized under State regulations. This was not the NPS's intent, and the final rule has been modified to allow for this practice.

22. Comment: One commenter stated the allowance in the proposed rule for using electronic calls to take big game (except moose) should be modified to allow electronic calls for all game (except moose).

NPS Response: The NPS agrees with the suggestion, which is consistent with State law. The NPS has modified the rule accordingly.

23. Comment: Some commenters objected to the practice of trapping and snaring generally due to the potential for user conflicts and safety concerns due to traps and snares on or near trails. Some commenters specifically objected to snaring bears. Some commenters said trapping should not be allowed near trails used by others in order to protect those visitors and their pets. Some commenters said trappers should be required to identify their traps with their name and contact information.

NPS Response: ANILCA generally allows for trapping (including snaring) in national preserves. Under this rule and adopted State law, there are restrictions on animals that may be trapped under a trapping license, types of traps, as well as restrictions on locations where traps may be set. Because pets are required to be leashed, traps—even those set near trails—have not been a concern historically. In the event that trapping presents safety concerns, the NPS will address those concerns on a case-by-case basis.

24. Comment: Commenters suggested there is an inconsistency between what is being proposed for NPS lands in Alaska and allowances in some Lower 48 parks, including taking coyotes year-round.

NPS Response: Units of the National Park System are ''united through their interrelated purposes and resources into one National Park System,'' and managed in a manner ''consistent with and founded in the purpose established by'' the NPS Organic Act, ''to the common benefit of all the people of the United States.'' 54 U.S.C. 100101. But units also are managed consistent with their enabling statutes and other laws specifically applicable to those units, such as ANILCA. Hunting of any kind is generally prohibited in units of the National Park System, 36 CFR 2.2, except where specifically authorized by statute, as is the case for national preserves in Alaska (as well as subsistence activities in other Alaska units). In those units that do allow hunting, hunting seasons for particular species generally vary from unit to unit and are often set by State law. When NPS sets seasons or other restrictions by regulation, it does so case by case, based on the resource and management needs of the particular unit.

25. Comment: Some commenters suggested that the rule should prohibit the more subtle means of affecting the natural functioning ecosystem, such as hunters not being required to obtain tags or permits for predators, same-day airborne hunting and trapping, and sale of raw hides and skulls.

NPS Response: Many of the activities described by the commenter are already prohibited under federal regulations. For example, same-day airborne hunting of big game animals, arctic fox, red fox, or lynx is not allowed on NPS lands. Additionally, sale of raw hides and skulls is not allowed under existing NPS regulations. The NPS has not identified a need for NPS-issued tags and permits and consequently has not required harvest permits and tags beyond those required by State regulations and federal subsistence regulations.

26. Comment: One commenter said that while ungulates will probably remain the focus of the State's intensive management program, it is conceivable that another species could become the focus in the future due to fads or economic interests. The commenter suggested that NPS needs the flexibility to include additional species when necessary to provide for naturally functioning ecosystems.

NPS Response: While naturally functioning ecosystems include natural diversity and abundances of native wildlife populations, the NPS does not believe it is necessary to modify the proposed rule to address this concern. Should the issue arise in the future, the NPS will work with the State and consider appropriate action at that time.

27. Comment: One commenter suggested adding ''intercepting'' wildlife to the list of prohibited actions that cannot be taken by an aircraft, snowmachine, or other motor vehicle. Also, the term ''positioning'' is used to refer to the practice of using snowmachines for lining caribou up for a shot. It should be clarified whether this practice is considered ''herding.''

NPS Response: Paragraph (g)(4) of this rule prohibits using an aircraft, snowmachine, off-road vehicle, motorboat, or other motor vehicle to harass wildlife, including chasing, driving, herding, molesting, or otherwise disturbing wildlife. Using an aircraft, snowmachine, or other motor vehicle to ''intercept'' or ''position'' wildlife is prohibited by this provision, because the wildlife would be (among other things) harassed, chased, driven, herded, molested, or otherwise disturbed by the use of the aircraft, snowmachine, or motor vehicle. As a result, the NPS does not believe it is necessary to revise the proposed rule to specifically prohibit ''intercepting'' or ''positioning'' wildlife as these activities are already covered by the rule.

28. Comment: Some commenters stated the NPS should also address bag limits for certain species, such as wolves.

NPS Response: The NPS generally believes bag limits are more appropriately addressed through the State regulatory process and Federal Subsistence Program in conjunction with harvest information and population data. Should bag limits become a concern in the future, the NPS will work with the State and the Federal Subsistence Board as appropriate.

29. Comment: Some commenters objected to prohibiting the harvest methods identified in the proposed rule as unnecessary since they duplicate State regulations already in effect or would eliminate harvest opportunities for Alaskans.

NPS Response: The NPS affirms current State prohibitions on harvest methods by codifying them as federal law. Should exceptions to these State prohibitions be made in the future, the NPS will consider whether to adopt the same exceptions for national preserves. The majority of existing harvest opportunities provided under State law will still be available for hunters in national preserves.

Annual List of Harvest Regulations Not Adopted

30. Comment: Some commenters objected to the provision in the proposed rule requiring the Regional Director to compile an annual list of State laws and regulations that are not adopted in national preserves because they are aimed at reducing predators. Some comments suggested that the NPS hold public hearings and a public comment period before the Regional Director places laws and regulations on this list. Other commenters stated this provision is inconsistent with ANILCA and would give superintendents too much discretionary authority.

NPS Response: The provision requiring the Regional Director to identify State laws and regulations not adopted under paragraph (f) is designed to remove any ambiguity about which State-authorized activities are prohibited on national preserves. The NPS does not believe that a hearing or public comment period is appropriate for the annual list because these activities will be prohibited by paragraph (f)(2) without any further action by the NPS or the Regional Director. The purpose of the list is to inform the public about which laws and regulations are not adopted by the NPS so that there is no confusion about what is allowed in national preserves. The list is expected to change only to the extent the State authorizes new predator reduction activities that otherwise would affect national preserves. The overall goal of this provision is to maintain the traditional status quo and prevent the introduction of new predator reduction activities in national preserves.

ANILCA allows the Secretary of the Interior (acting through the NPS) to restrict sport hunting and trapping in national preserves after consultation with the State of Alaska, and does not diminish the authority of the Secretary of the Interior over the management of public lands. See the Background section of this final rule for more information about NPS authority to promulgate this rule. The NPS believes that compiling and annually updating a list of the activities prohibited by paragraph (f) is consistent with the statutory authority provided to the NPS for the management of national preserves.

Taking Bears Over Bait

31. Comment: Some commenters stated that the practice of baiting black bears and brown bears is appropriate because it will not have adverse ecological or public safety effects. Others commented that baiting black bears and brown bears should be prohibited because it may create public safety issues, food-conditioned bears, or impact natural populations or processes.

NPS Response: The NPS proposed prohibiting the harvest of brown bears over bait to avoid public safety issues, to avoid food conditioning bears and other species, and to maintain natural bear behavior as required by the NPS legal and policy framework. By design, baiting typically uses human or pet food to alter the natural behavior of bears to predictably attract them to a specific location for harvest. Land and wildlife management agencies strive to eliminate the feeding of bears through individual and collective educational efforts, due to the increased likelihood that food-conditioned bears are killed by agency personnel or the public in defense of life or property. Food-conditioned bears are also believed more likely to cause human injury. To that end, NPS regulations prohibit feeding wildlife and the practice of baiting is at odds with this.

Because the concerns presented by taking brown bears over bait also apply to black bear baiting, the NPS requested public comment on whether taking black bears over bait should be allowed to continue on national preserves. After reviewing public comment, the NPS has decided to prohibit taking black bears over bait in national preserves. This decision is consistent with State regulations applicable to Denali State Park, where taking of wildlife is authorized but taking black bears over bait is prohibited (see 2014–2015 Alaska Hunting Regulations, p. 27 and 78 and 5 AAC 92.044 for game management units where the practice is authorized).

Bait stations tend to be located in accessible areas due to the infrastructure (typically a 55 gallon drum) and quantity (including weight) of bait used to engage in this activity and the frequency with which the stations must be replenished. Because of the accessibility of these areas, they are typically used by multiple user groups, which contributes to the public safety concerns associated with baiting. Although there are State regulations that prohibit bait stations within a certain distance of structures (cabins/residences), roads, and trails, these distances lack biological significance relative to bears, whose home ranges can include tens to hundreds of square miles.

32. Comment: Some commenters stated that bear baiting should be allowed in national preserves because it is a historical practice that predates the establishment of national preserves and it a customary practice by many Alaskans. Commenters also stated the practice should be allowed because the amount of take is or would be small.

NPS Response: According to information provided by the State of Alaska, harvest of black bears over bait was authorized by State regulations in 1982. The creation of all NPS areas in Alaska preceded this date. Harvest of bears over the remains of legally-harvested animals not required to be salvaged will continue to be lawful provided the remains are not moved. To the extent the practice of baiting bears is a customary and traditional practice by rural residents, those uses may be authorized for Federally qualified rural residents pursuant to regulations adopted by the Federal Subsistence Board.

The NPS recognizes that the number of bears harvested over bait in national preserves may not be large. However, this provision is not based on how many bears are harvested or whether that harvest would impact bear population levels. It is based on the legal and policy framework that governs national preserves and calls for maintaining natural ecosystems and processes and minimizing safety concerns presented by food-conditioned bears.

33. Comment: One commenter recommended the definition of bait exclude legally taken fish and that bait should exclude legally taken wildlife that is not required to be salvaged under federal as well as State law. A comment was received that game that died of natural causes should not be considered bait.

NPS Response: The NPS has modified the definition of bait in a manner that excludes native fish, consistent with State law. Upon review, the NPS determined it is not necessary to reference State or federal law regarding salvage requirements in the definition of bait. The result is that parts of legally taken fish or wildlife that are not required to be salvaged are not considered bait if the parts are not moved from the kill site. The rule excludes from the definition of bait game that died of natural causes, if not moved from the location where it was found.

Taking Black Bears With Artificial Light at Den Sites

34. Comment: Some comments stated that the use of artificial light to aid the harvest of black bears in dens should be allowed to ensure proper species identification, prevent take of cubs or sows with cubs, and facilitate a human shot placement. Others commented that the use of artificial light to aid the harvest of black bears in dens should be prohibited due to effects on ecological processes and populations and the potential for dangerous orphaned cubs.

NPS Response: Although artificial light may, in some cases, aid the harvest of black bears in dens by assisting with species identification and shot placement, the NPS does not support authorizing this practice for sport hunting in national preserves. For rural subsistence users, the NPS believes this matter is more appropriately addressed by the Federal Subsistence Board. The final rule maintains the proposed prohibition on using artificial light to take wildlife, subject to certain exceptions.

Using Dogs To Hunt Black Bears

35. Comment: In response to a question in the proposed rule, some commenters supported the use of unleashed dogs to hunt black bears pursuant to a State permit. Some commenters stated that the use of dogs to hunt black bears has been allowed since 1970 and is not historically illegal. Other commenters opposed the use of dogs to hunt black bears. These comments stated that this activity would increase stress and trauma for the dogs and bears, reduce bear populations in national preserves, disrupt the natural balance of predator-prey dynamics, alter bear feeding patterns, harass other wildlife, transmit diseases to wildlife, interfere with other sport and subsistence hunters, and be dangerous for the dogs and humans in the area (including by driving bears into roadways and onto private property). Several comments stated that dogs used for hunting roam over large portions of the land, often out of the sight and control of their handlers. Some comments stated that this activity is unethical, unsportsmanlike, and does not have a traditional or cultural basis in Alaska. Other comments stated that dogs are often used to ''tree'' bears, which makes it difficult to determine the sex of the bear and could result in the killing of females with cubs.

NPS Response: Commenters are correct that using dogs to hunt black bears is not ''historically illegal.'' While State of Alaska law generally prohibits taking big game with the aid or use of a dog, there is an exception for using a dog to take black bears pursuant to a non-transferable permit issued by the ADF&G. The NPS agrees that this practice could have some of the adverse impacts suggested by commenters who oppose the practice. The NPS also believes the use of unleashed dogs to hunt black bears is one of the practices that is inconsistent with the traditional ''sport hunting'' that is authorized by ANILCA, as discussed above. The rule generally prohibits taking big game with the aid of use of a dog. The proposed rule has been modified to eliminate an exception that would have allowed the use of dogs to harvest black bears under a State permit.

36. Comment: Some commenters supported the use of unleashed dogs to hunt ''problem animals'' and the use of leashed dogs to hunt wounded black bears.

NPS Response: There is no allowance in State law to use unleashed dogs to hunt ''problem animals.'' Current State law allows use of a single, leashed dog in conjunction with tracking and dispatching a wounded big game animal, including black bear. The intent of the leash requirement is to ensure that native wildlife are not pursued, harassed, or killed by unleashed dogs and to prevent any contact between native wildlife and domestic dogs. The State-authorized use of a single, leashed dog in conjunction with tracking and dispatching a wounded big game animal will remain authorized in national preserves. The NPS will take appropriate action to protect the safety of park visitors and other wildlife from problem animals, such as bears.

37. Comment: Some commenters supported using sled dogs to travel to and from hunting and trapping areas, in search of game, and to haul out taken game, but not to chase wildlife.

NPS Response: Sled dogs are allowed under 16 U.S.C. 3121(b) of ANILCA for subsistence uses and under 16 U.S.C. 3170(a) of ANILCA for other traditional activities, unless prohibited or restricted on a site specific basis. There are currently no prohibitions or restrictions on this activity in areas where hunting and trapping are authorized. Herding, harassing, hazing, or driving wildlife is prohibited under NPS regulations. This includes ''chasing'' wildlife.

Wolves and Coyotes

38. Comment: Several commenters supported the limitations on taking wolves and coyotes in the proposed rule, and suggested additional protections such as extending the duration of the no-take period and imposing bag limits. These comments were concerned about hunting pressure, declining populations, and protecting pregnant females to avoid orphaned pups and unsuccessful rearing. Other commenters opposed the limitations on taking wolves and coyotes in the proposed rule, and suggested additional allowances for taking these species, including adoption of the State hunting seasons. Several commenters stated that extended hunting seasons for wolves and coyotes allow for a traditional form of hunting specifically authorized under the State subsistence program, and are not meant to be predator control.

NPS Response: The rule prohibits taking wolves and coyotes from May 1 through August 9. These dates reflect previously longstanding State harvest seasons that provided harvest opportunities while maintaining viable wolf and coyote populations. The rule maintains the decades-old management paradigm of State and federal managers, rather than adopting recently liberalized State regulations that lengthen the hunting seasons. Should wolf or coyote population levels become a concern in the future, the NPS will work with the State and consider appropriate action at that time.

39. Comment: Some commenters stated that coyotes are not native to Alaska.

NPS Response: Coyotes are native to North America, and while coyotes may not have historically occupied all of their current range, their expansion most likely occurred through natural processes. Consequently, the NPS manages coyotes in the same manner as other native species consistent with NPS Management Policies (§§ 4.1, 4.4.1, 4.4.1.2, 4.4.2).

40. Comment: A few commenters questioned whether wolf pelts taken during the denning season have limited value.

NPS Response: The NPS understands that some individuals may have uses for wolf pelts that are harvested outside the normal trapping season. This rule, however, protects wolves during the denning season when they are vulnerable. The rule preserves the opportunity to harvest wolves when the pelts are thicker for cold winter temperatures. A pelt that has begun to shed out for summer is thinner, may become patchy, and for these reasons is not generally considered as valuable.

Swimming Caribou

41. Comment: One commenter stated that the proposed prohibition on taking swimming caribou would be difficult to enforce because the harvest opportunities are along the river's edge and animals often fall in the low spots or the water. Another commenter supported the prohibition, noting that there are sufficient opportunities for sport hunters to harvest caribou on land.

NPS Response: NPS agrees that there are adequate opportunities for sport hunters to harvest caribou on land. Although there may be a few situations where it is difficult to tell whether a caribou was taken while swimming, the NPS believes that the prohibition will be enforceable. Also, under existing State regulations, this practice is limited to waters in GMUs 23 and 26. Noatak, Gates of the Arctic, and Bering Land Bridge are the only national preserves within these GMUs. To the extent individuals who are not federally qualified subsistence users engage in this activity elsewhere (*e.g.,* Onion Portage within Kobuk Valley National Park), such use is not authorized under existing NPS regulations, which allow only federally qualified subsistence users to hunt within certain national parks and monuments in Alaska.

42. Comment: Several commenters opposed the prohibition on the take of swimming caribou, stating that it would prevent those who no longer live in rural Alaska from harvesting foods in a traditional manner. Commenters stated that former residents would not be allowed to return to hunt or to assist elders with hunting in traditional ways. Other commenters supported the proposed prohibition of taking caribou while swimming, noting that it is unsporting and not consistent with fair chase.

NPS Response: The NPS recognizes that taking caribou while swimming is a customary and traditional subsistence practice in some areas of the State. The NPS supports continuation of this practice under federal subsistence regulations in NPS units. The NPS also agrees with the comment that the practice of taking caribou while swimming is not consistent with fair chase and thus believes it is not appropriate to allow as a sport hunting practice. Although former local residents who no longer qualify to hunt under federal subsistence regulations will not be able to engage in such subsistence harvests, they may participate in other aspects of the traditional practice.

Obstruction of Hunting

43. Comment: Some commenters opposed the proposed prohibition on obstructing hunting activities as unnecessary or providing special treatment to hunters. Others questioned the need for the provision because it is already in State law.

NPS Response: In the past, the NPS has received reports of individuals actively attempting to obstruct others from hunting. While this conduct is prohibited under State law, it is not currently prohibited under NPS regulations. Consequently, in the event of a violation of this type in a national preserve, only the State could take enforcement action. This rule allows the NPS also to take enforcement action. This protects the lawful rights of hunters in national preserves, but does not afford them special treatment above what they are currently entitled to by State law.

Bait for Fishing

44. Comment: Commenters generally supported using native species as bait for fishing. Some commenters suggested the species used should be obtained from the waters being fished to avoid introducing a species that is native to

Alaska but not native to a particular watershed.

NPS Response: The NPS agrees that bait species should be limited to those native to Alaska, but does not believe that allowing the use of species not native to a particular watershed poses a risk that new species will be introduced into that watershed. Existing State and federal regulations already prohibit the use of live fish for bait in fresh water, and using dead fish or unfertilized eggs removed from a harvested fish will not result in the introduction of new species that are not native to a particular watershed. In marine waters, existing regulations already require that any fish used for bait come from the same waters being fished.

45. Comment: One commenter supported allowing bait for fishing but stated the rule is not necessary because State regulations that allow bait apply to NPS units.

NPS Response: Section 13.40(b) provides that fishing must be consistent with 36 CFR 2.3. Section 2.3 prohibits the use of live or dead minnows or other bait fish, amphibians, nonpreserved fish eggs or fish roe as bait for fishing in fresh waters, along with methods other than hook and line. Consequently this rule is necessary to allow the use of native species of fish or fish eggs as bait for fishing.

46. Comment: Some commenters supported the intent to allow bait for fishing since it is a common practice and commonly allowed in Alaska, but said it would create confusion on waters where the State has prohibited bait. These commenters also noted the State allows many forms of bait that would not be considered native species, such as natural or synthetic scents, and natural or processed vegetable matter.

NPS Response: NPS regulations adopt non-conflicting State regulations. Under existing NPS regulations, the use of bait is allowed in accordance with State law under 36 CFR 2.3 except for the use of fish, amphibians or their eggs. This rule allows the use of native fish, amphibians, and their eggs as bait if authorized by the State. If the State does not allow the use of these types of bait in waters within NPS areas, State law will govern and the use of native fish, amphibians, and their eggs as bait will not be allowed.

Updating Federal Subsistence Regulations

47. Comment: Some commenters opposed removal of regulatory language providing for consultation with the State regarding potential closures to subsistence harvest of fish and wildlife. A suggestion was made to retain the provision adopting non-conflicting State laws for subsistence harvest of fish and wildlife. A comment also suggested adding several provisions to the subsistence closure procedures in 36 CFR 13.490, including consultation with various stakeholders, holding public hearings in the affected vicinity, and holding hearings in coordination with other meetings.

NPS Response: The existing provision that adopts non-conflicting State laws is not necessary due to the assumption by the Federal Subsistence Board of regulatory authority over Title VIII subsistence harvest of fish and wildlife. Federal subsistence regulations, which apply in NPS units where Title VIII subsistence is allowed, include regulatory language that adopts non-conflicting State laws. The provision in 36 CFR 13.490 is no longer necessary and will be removed by this rule.

Upon review of comments and considering the practices of the Federal Subsistence Board, the NPS agrees with the recommendation to retain the language providing for consultation with the State prior to the NPS implementing closures to subsistence take of fish and wildlife. Because harvest is regulated by the Federal Subsistence Board, the NPS has modified the proposed rule to also include consultation with the Federal Subsistence Board.

Finally, for consistency with 36 CFR 13.50, which was modified based upon comments (addressed below), the rule has been modified to specify that public hearings will be held near the affected park unit (rather than the ''affected vicinity'') prior to implementing the management action in nonemergency situations.

Updating Closure and Restriction Procedures

48. Comment: Some commenters objected to the changes in 36 CFR 13.50 as inconsistent with ANILCA or not appropriate for Alaska.

NPS Response: The changes to 36 CFR 13.50 bring procedures for implementing closures and restrictions more in line with procedures that apply to the entire National Park System under 36 CFR 1.5, as well as procedures used by Alaska State Parks. 11 AAC 12.355. The public will benefit from aligning procedures with other NPS units as well as Alaska State Parks. This consistency will enable the public to more effectively engage managers regarding their uses of the public lands and the resources on them.

While commenters referred generally to the proposed changes as being inconsistent with ANILCA, the only provision cited was 16 U.S.C. 3202. That section contains general savings provisions preserving the Secretary's authority to manage public lands and preserving the State's non-conflicting authority to manage fish and wildlife on those lands. Nothing in that section is specifically relevant to the closure and restriction provisions of 36 CFR 13.50; accordingly the NPS finds no conflict between ANILCA and these procedural updates.

49. Comment: Some commenters stated the proposed rule would give too much authority to the superintendents to adopt restrictions, specifically on taking of fish or wildlife for sport purposes. Some commenters stated that closures or restrictions must be based upon demonstrated biological considerations (*e.g.,* wildlife population data).

NPS Response: Federal statutes, including ANILCA, provide the NPS with substantial discretion in managing units of the National Park System. Generally, National Park System regulations need only be ''necessary or proper for the use and management of System units.'' 54 U.S.C. 100751. With respect to sport hunting in national preserves in Alaska, Congress authorized the NPS to restrict these activities for reasons of ''public safety, administration, floral and faunal protection, or public use and enjoyment.'' 16 U.S.C. 3201. The NPS thus is not required to base its management decisions regarding these restrictions only on biological considerations. The rule maintains the superintendent's long established authority to make management decisions for NPS units based upon a variety of criteria. The NPS plans to continue to require review of all proposed closures and restrictions at the regional level.

50. Comment: Some commenters were concerned that the proposed changes to 36 CFR 13.50 would limit Alaskans' ability to comment on potential closures and restrictions on NPS-managed areas by shortening the comment period, soliciting comments from non-residents of Alaska, and reducing the number of public meetings.

NPS Response: While hearings are required in certain circumstances (*e.g.,* restricting subsistence harvest of fish or wildlife under Title VIII of ANILCA or access authorized under 16 U.S.C. 3170(a)), there is no statutory requirement to take public comment on closures or restrictions that are not required to be published in the **Federal Register**. The NPS believes, however, that public involvement is an important component of managing NPS units.

Alaskans and all Americans have an important say in how these national interest lands are managed. Accordingly, except in emergencies, the rule requires an opportunity for public comment, including holding at least one public meeting near the affected NPS unit, prior to adopting a closure or restriction related to taking fish or wildlife. The changes to § 13.50 will not limit any existing opportunities, including public meetings, for Alaskan residents to comment on proposed closures and restrictions for NPS units in Alaska. The NPS posts online proposed closures and restrictions for NPS units in Alaska and invites public comment on them. The NPS intends to continue this practice.

51. Comment: Some commenters objected to removing the requirement that the NPS hold a hearing before implementing closures or restrictions on taking of fish and wildlife for sport purposes. Some were concerned that the NPS would cease meeting with local communities or that the change would give superintendents too much discretion to decide whether to meet with local communities. Some commenters stated the NPS should not consider the time or expense to the government or anticipated number of attendees in determining whether to hold public hearings.

NPS Response: The proposed rule would have replaced the existing regulatory requirement to hold a hearing in the affected vicinity with a requirement to provide an opportunity for public comment, which could include a written comment period, public meeting, public hearing, or a combination thereof. After reviewing comments and considering the similar procedures used by the BOG and the Federal Subsistence Board, the NPS modified the proposed rule to add a requirement to hold one or more public meetings near the affected park unit prior to implementing a closure or restriction on taking fish and wildlife in national preserves, except in the case of emergencies. The NPS will attempt to hold public meetings in conjunction with other events, like Subsistence Resource Commission meetings, when possible. The NPS will consider holding more than one public meeting depending the nature of the action, local interest, and other opportunities for engagement. The rule will also require the NPS to continue the current practice of providing an opportunity for public comment prior to implementing proposed closures and restrictions related to taking fish and wildlife. The NPS intends to continue its current practice of accepting written comments submitted electronically or by mail or hand delivery. This will give Alaskans and other Americans an opportunity to provide meaningful input on these management actions.

52. Comment: Some comments suggested the NPS provide public notice and hold a hearing prior to adopting emergency closures relating to fish and wildlife.

NPS Response: Although the NPS supports providing the public with a meaningful opportunity to comment, in certain circumstances action may be necessary to protect wildlife or public safety before there is an opportunity for public comment or a hearing. The NPS will provide appropriate notice of emergency closures and restrictions in accordance with the provisions of 36 CFR 13.50.

53. Comment: Some commenters stated the proposed rule would eliminate a requirement to do written determinations stating the basis for closures, restrictions, and other designations.

NPS Response: Although the procedures in 36 CFR 1.5(c) require a written determination of need explaining the reasons for closures or restrictions on public use, the current procedures in § 13.50 do not. The NPS however, has provided such determinations for all proposed closures and restrictions in NPS units in Alaska to better inform the public about the reasons for its decisions. This comment highlights the complexity regarding the various procedural regulations that currently apply to NPS units in Alaska. The NPS believes it is in the public's interest to streamline procedures as much as possible in order to make them more consistent. This will make it easier for the public to be involved in NPS decision-making in Alaska. Accordingly, the NPS has decided to apply the procedures of 36 CFR 13.50, as revised in this rule, to all closures and restrictions in NPS units in Alaska unless a more specific regulation in part 13 provides otherwise (*i.e.,* 36 CFR 13.490 pertaining to closures to subsistence harvest of fish and wildlife). These revised procedures that apply to all NPS units in Alaska require a written determination explaining the basis of the restriction.

54. Comment: Some commenters objected to utilizing web-based tools for information sharing and taking public comment since not all Alaskans have reliable internet. Other commenters objected to using the internet because it is easier for individuals outside Alaska to provide input. Some commenters interpreted the proposed rule to imply that the NPS will engage the public using social media exclusively.

NPS Response: The NPS acknowledges that some individuals, especially in rural Alaska, may not have reliable internet access or may prefer other methods of communicating with the NPS. The methods of providing notice in the rule are consistent with NPS practices in place in Alaska for more than a decade. The primary method of notifying the public of closures or restrictions has been posting notice online and disseminating press releases by email. It has been the practice for the NPS to invite public comment through electronic means as well as by mail or hand delivery. The majority of public comments are received electronically. The NPS will continue to accept written comments through electronic and traditional means (mail or hand delivery). The NPS will also use other notification procedures such as posting in local post offices and other public places when practical. Individuals may also request copies of the park compendium and other NPS documents by mail or in person. Social media is a valuable tool to inform as well as engage a certain segment of the public, but it is not, and will not be, the only way the NPS engages and communicates with the public. The NPS believes that using the internet will make it easier for some segments of the American public, regardless of residency, to provide input on proposed management actions for NPS units in Alaska. This is appropriate because National Park System units are federal lands that are protected and preserved for all Americans.

55. Comment: Some commenters suggested that the proposed rule should provide opening procedures.

NPS Response: The procedures in the rule apply to the termination and relaxation of closures and restrictions, which includes actions that open areas and allow activities that had been closed or restricted.

56. Comment: Some commenters suggested retaining the distinction between permanent and temporary restrictions. These commenters recommend temporary restrictions be limited to 12 months and rulemaking be required for all permanent restrictions or those restrictions in place longer than 12 months. Other comments stated the existing 30-day limitation on emergency closures should be retained with no extensions.

NPS Response: The categories distinguishing permanent and temporary closures or restrictions have been problematic and difficult to implement, as noted by the State and others during the annual compendium review process on several occasions. Under current regulations, closures or restrictions in place for more than 12 months must be implemented by rulemaking and cannot be extended, regardless of significance or public interest. The result of this structure is that the NPS must repropose and reissue temporary closures or restrictions each year, even in circumstances where there is little public interest in the action, or where the action is an insignificant management decision. The existing framework is overly rigid and complicated, and unnecessarily compromises the NPS's ability to protect resources and provide for public use and enjoyment. The NPS has determined that the criteria-based rulemaking structure that exists in the nationwide NPS regulations (and is mirrored by Alaska State Parks) provides a better framework. A criteria-based framework requires notice and comment rulemaking based on the impact the closure or restriction will have on the values, resources, and visitors of the park unit. This framework allows the superintendent to implement closures or restrictions that do not significantly impact values, resources, or visitor use without needing to publish a rule in the **Federal Register** or propose the same action again every year. For example, a prohibition on smoking near fuel storage tanks would not necessarily require a rulemaking, but closing an area to all sport harvest on a permanent basis would. The criteria-based framework allows managers to be more flexible and adapt to changing circumstances. The improved consistency with other NPS units and Alaska State Parks will also make it easier for the public to be involved in decision-making regarding the use of public lands in Alaska.

With regard to the duration of emergency closures, the NPS rule is more consistent with the practice of other agencies and NPS regulations that apply outside of Alaska. The existing regulations limit emergency closures to 30 days without extension. Federal subsistence regulations regarding subsistence harvest of fish and wildlife provide for emergency closures of up to 60 days and allow for extensions. National Park System-wide regulations and Alaska State Parks regulations do not provide a time limit on emergency closures. 36 CFR 1.5, 11 AAC 12.355. With respect to restrictions on taking fish and wildlife for sport purposes in national preserves, the NPS adopts the 60-day timeframe and allows for extensions—after consultation with the State and public comment (including a public meeting)—if the emergency persists. The NPS believes the public will benefit from this consistency with respect to emergency closures or restrictions on taking of fish or wildlife. Other emergency actions will have no explicit expiration date and may exist until the emergency is resolved. This is consistent with regulations for NPS units located outside of Alaska and for Alaska State Parks.

57. Comment: Some commenters stated the NPS should retain the provision requiring consultation with the State and with ''representatives of affected user groups'' prior to adopting restrictions on the take of wildlife for sport purposes, including Subsistence Resource Commissions, federal subsistence regional advisory councils, local fish and game advisory committees, tribes, and others. Some commenters also stated the NPS must implement the recommendations of Subsistence Resources Commissions unless the criteria of 16 U.S.C. 3118(b) apply.

NPS Response: 16 U.S.C. 3201 requires the NPS to consult with the State prior to prescribing restrictions relating to hunting, fishing, or trapping in national preserves. The rule does not eliminate that statutory requirement; it has moved this requirement into § 13.50 because it relates to closures and restrictions. The rule also requires the NPS to provide an opportunity for public comment, including one or more public meetings near the affected national preserve prior to implementing a closure or restriction on taking fish or wildlife. This will provide representatives of affected user groups an opportunity to provide comments to the NPS prior to the action being implemented. User groups are invited and encouraged to provide input on all such proposed actions.

The NPS agrees that input from advisory groups, NPS Subsistence Resource Commissions, and others is important and valuable and the NPS encourages these groups to engage with the park superintendents on topics of interest. The NPS, however, does not agree that the provisions of 16 U.S.C. 3118(b) apply as broadly as suggested. Under 16 U.S.C. 3118, Subsistence Resource Commissions are established for areas designated as national parks and monuments (not national preserves) to provide subsistence hunting program recommendations. ANILCA further provides that a subsistence hunting program recommendation for national parks and monuments must be implemented unless it ''violates recognized principles of wildlife conservation, threatens the conservation of healthy population of wildlife . . . is contrary to the purposes for which the park or park monument is established, or would be detrimental to the satisfaction of subsistence needs of local residents.'' While Subsistence Resource Commissions provide valuable input on multiple topics that affect national parks, monuments, and national preserves, the Subsistence Resource Commission's statutory charge is specific to Title VIII subsistence hunting program recommendations in national parks and monuments. This rule does not restrict Title VIII subsistence and applies only to sport harvest on national preserves. Therefore 16 U.S.C. 3118(b) does not apply.

58. Comment: Some commenters stated that the factors in the rule that must be considered by superintendents prior to adopting a closure or restriction are ambiguous and give too much discretion to park superintendents. Other commenters suggested adding factors, including ''natural,'' ''natural and healthy,'' ''healthy,'' and ''species of concern,'' to those in the proposed rule. Other commenters suggested retaining the reference to emergencies.

NPS Response: The factors that must be considered by superintendents place appropriate guidelines around their authority to manage NPS units in Alaska. The discretionary authority granted to superintendents recognizes that they are subject matter experts regarding management of the park unit and allows them to take action and respond to changing circumstances in the unit.

Under the existing regulations, the superintendent must consider factors including public health and safety, resource protection, protection of cultural or scientific values, subsistence uses, conservation of endangered or threatened species, and other management considerations in determining whether to adopt closures or restrictions on an emergency basis. These factors appear elsewhere in 36 CFR part 13 (*e.g.,* 36 CFR 13.460(b) and 13.485(c)). The NPS proposed to modify this section by requiring the superintendent to consider these factors for all closures and restrictions (not just emergencies), and adding the criteria of ''naturally functioning ecosystems'' based on *NPS Management Policies 2006,* which implement the NPS Organic Act.

In the final rule, the NPS has decided that adding a requirement that the superintendent consider protecting ''naturally functioning ecosystems'' is unnecessary because this consideration is encompassed by the existing requirement that the superintendent consider ''resource protection.'' The NPS considered adding the terms ''natural,'' ''natural and healthy,'' ''healthy,'' and ''species of concern,'' but determined such terms are not necessary because they are a part of ''resource protection'' or in some cases ''conservation of endangered or threatened species.''

Changes From the Proposed Rule

After taking the public comments into consideration and after additional review, the NPS made the following substantive changes in the final rule:

§ 13.1	Added an exception to the definition of ''bait'' for legally taken fish not required to be salvaged if not moved from the kill site. This change is consistent with State law and would exclude this practice from the prohibition on using bait in the rule. The term ''game'' was changed to ''wildlife'' for consistency with NPS terminology.
§ 13.42(g)	Delayed implementation of the prohibited methods of taking wildlife until January 1, 2016.
§ 13.42(g)(8)	Added an allowance for using electronic calls to take all game animals (not limited to big game animals) except for moose.
§ 13.42(g)(10)	Removed an exception that would have allowed the taking black bears over bait, which is now prohibited.
§ 13.42(g)(11)	Removed an exception that would have allowed the use of dogs to take black bears under a State permit.
§ 13.42(g)(14)	Added an exception to the prohibition on taking a fur animal by disturbing or destroying a den to allow taking muskrats at pushups or feeding houses.
§ 13.42(e)	Modified an existing requirement that individuals transporting wildlife through park areas must identify themselves and the location where the wildlife was taken to any NPS personnel. This information must now only be given to NPS law enforcement personnel. This type of information is relevant for law enforcement purposes and accordingly, the identification requirement should be limited to law enforcement officers.
§ 13.50(a)	Modified to reflect the applicability of § 13.50 to all NPS closures and restrictions in Alaska unless more specific procedures in part 13 apply.
§ 13.50(b)	Changed the title from ''criteria'' to ''factors'' because the regulatory text refers to the considerations as ''factors.'' Removed ''protecting the integrity of naturally functioning ecosystems'' as factor that must be considered by the superintendent in determining whether to close an area or restrict an activity.
§ 13.50(c)	Change the title from ''duration'' to ''rulemaking requirements'' to accurately reflect the content of the subsection. Removed the provision limiting all emergency closures and restrictions to 60 days.
§ 13.50(d)	Added a provision requiring written explanation of the reasons for implementing, relaxing, or terminating a closure or restriction, except in emergencies.
§ 13.50(e)	Prior to implementing nonemergency closures or restrictions on taking fish or wildlife, added a requirement to hold one or more public meetings near the affected NPS unit. Added a 60-day time limit for emergency closures or restrictions on taking fish or wildlife with extensions only upon consultation with the State and public comment, including a meeting near the affected NPS unit.
§ 13.50(f)	Closures or restrictions will be ''posted on the NPS website'' rather than ''effective upon publication on the NPS website.'' This change reflects that the NPS may post closures or restrictions on the NPS website prior to them taking effect. Also added a requirement to compile a written list, updated annually, of closures and restrictions which is posted on the NPS website.
§ 13.50	Removed existing regulations on ''Openings'' and ''Facility closures and restrictions'' because they are redundant with the revisions to this section.
§ 13.50(g)	Shortened for clarity and brevity.
§ 13.490	Added a requirement to consult with the State and the Federal Subsistence Board before temporary restrictions on taking fish or wildlife for subsistence uses under Title VIII of ANILCA. Updated the language regarding location of hearings to near the ''affected NPS unit'' for consistency with the changes in § 13.50.

Compliance With Other Laws, Executive Orders, and Department Policy

Regulatory Planning and Review (Executive Order 12866)

Executive Order 12866 provides that the Office of Information and Regulatory Affairs (OIRA) in the Office of Management and Budget will review all significant rules. OIRA has determined that this rule is not significant.

Executive Order 13563 reaffirms the principles of Executive Order 12866 while calling for improvements in the nation's regulatory system to promote predictability, to reduce uncertainty, and to use the best, most innovative, and least burdensome tools for achieving regulatory ends. The executive order directs agencies to consider regulatory approaches that reduce burdens and maintain flexibility and freedom of choice for the public where these approaches are relevant, feasible, and consistent with regulatory objectives. Executive Order 13563 emphasizes further that regulations must be based on the best available science and that the rulemaking process must allow for public participation and an open exchange of ideas. We have developed this rule in a manner consistent with these requirements.

Regulatory Flexibility Act

This rule will not have a significant economic effect on a substantial number of small entities under the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*). This certification is based on the cost-benefit and regulatory flexibility analyses found in the report entitled ''Cost-Benefit and Regulatory Flexibility Analyses: Proposed Revisions to Wildlife Harvest Regulations in National Park System Alaska Region'' which can be viewed online at *http://parkplanning.nps.gov/akro,* by clicking the link entitled ''Amend Hunting and Trapping Regulations in National Preserves In Alaska'' and then clicking the link entitled ''Document List.''

Small Business Regulatory Enforcement Fairness Act (SBREFA)

This rule is not a major rule under 5 U.S.C. 804(2), the SBREFA. This rule:

a. Does not have an annual effect on the economy of $100 million or more.

b. Will not cause a major increase in costs or prices for consumers, individual industries, federal, state, or local government agencies, or geographic regions

c. Does not have significant adverse effects on competition, employment, investment, productivity, innovation, or the ability of U.S. based enterprises to compete with foreign-based enterprises.

Unfunded Mandates Reform Act

This rule does not impose an unfunded mandate on state, local, or tribal governments or the private sector of more than $100 million per year. The rule does not have a significant or unique effect on state, local or tribal governments or the private sector. A statement containing the information required by the Unfunded Mandates Reform Act (2 U.S.C. 1531 *et seq.*) is not required.

Takings (Executive Order 12630)

This rule does not effect a taking of private property or otherwise have taking implications under Executive Order 12630. A takings implication assessment is not required.

Federalism (Executive Order 13132)

Under the criteria in section 1 of Executive Order 13132, this rule does not have sufficient federalism implications to warrant the preparation of a Federalism summary impact statement. The rule's effect is limited to federal lands managed by the NPS in Alaska and it will not have a substantial direct effect on state and local government in Alaska. A Federalism summary impact statement is not required.

Civil Justice Reform (Executive Order 12988)

This rule complies with the requirements of Executive Order 12988. Specifically, this rule:

(a) Meets the criteria of section 3(a) requiring that all regulations be reviewed to eliminate errors and ambiguity and be written to minimize litigation; and

(b) Meets the criteria of section 3(b)(2) requiring that all regulations be written in clear language and contain clear legal standards.

Consultation with Indian Tribes (E.O. 13175 and Department policy) and ANCSA Native Corporations

The Department of the Interior strives to strengthen its government-to-government relationship with Indian Tribes through a commitment to consultation with Indian Tribes and recognition of their right to self-governance and tribal sovereignty. We have evaluated this rule under the criteria in Executive Order 13175 and under the Department's tribal consultation and Alaska Native Claims Settlement Act (ANCSA) Native Corporation policies and have determined that tribal consultation is not required because the rule will have no substantial direct effect on federally recognized Indian tribes. While the NPS has determined the rule will have no substantial direct effect on federally recognized Indian tribes or ANCSA Native Corporation lands, water areas, or resources, the NPS consulted with Alaska Native tribes and Alaska Native Corporations on the proposed rule, as discussed above.

Paperwork Reduction Act (44 U.S.C. 3501 et seq.)

This rule does not contain information collection requirements, and a submission to the Office of Management and Budget under the Paperwork Reduction Act is not required. We may not conduct or sponsor and you are not required to respond to a collection of information unless it displays a currently valid OMB control number.

National Environmental Policy Act

The NPS has analyzed this rule in accordance with the criteria of the National Environmental Policy Act (NEPA) and 516 DM. We prepared an environmental assessment entitled ''Wildlife Harvest On National Park System Preserves In Alaska'' (EA) to determine whether this rule will have a significant impact on the quality of the human environment. This rule does not constitute a major Federal action significantly affecting the quality of the human environment, and an environmental impact statement is not required, because we reached a Finding of No Signficant Impact (FONSI). The EA and FONSI are available online at *http://www.parkplanning.nps.gov/akro,* by clicking on the link entitled ''Amend Hunting and Trapping Regulations in National Preserves In Alaska'' and then clicking on the link entitled ''Document List.''

Effects on the Energy Supply (Executive Order 13211)

This rule is not a significant energy action under the definition in Executive Order 13211. A Statement of Energy Effects is not required.

Drafting Information

The primary authors of this regulation are Jay Calhoun, Regulations Program Specialist, National Park Service, Division of Jurisdiction, Regulations, and Special Park Uses; Philip Hooge, Denali National Park and Preserve; Barbara Cellarius, Wrangell-St. Elias National Park and Preserve; and Guy Adema, Debora Cooper, Joel Hard, Grant Hilderbrand, Brooke Merrell, Bud Rice, and Andee Sears of the Alaska Regional Office, National Park Service.

List of Subjects in 36 CFR Part 13

Alaska, National Parks, Reporting and recordkeeping requirements.

In consideration of the foregoing, the National Park Service amends 36 CFR part 13 as set forth below:

PART 13—NATIONAL PARK SYSTEM UNITS IN ALASKA

■ 1. The authority citation for part 13 continues to read as follows:

Authority: 16 U.S.C. 3124; 54 U.S.C. 100101, 100751, 320102; Sec. 13.1204 also issued under Sec. 1035, Pub. L. 104–333, 110 Stat. 4240.

■ 2. In § 13.1, add in alphabetical order the terms ''Bait'', ''Big game'', ''Cub bear'', ''Fur animal'', ''Furbearer'', and ''Trapping'' to read as follows:

§ 13.1 Definitions.

* * * * *

Bait means, for purposes of taking wildlife other than fish, any material used to attract wildlife by sense of smell or taste except:

(1) Parts of legally taken wildlife or fish that are not required to be salvaged if the parts are not moved from the kill site; or

(2) Wildlife or fish that died of natural causes, if not moved from the location where it was found.

Big game means black bear, brown bear, bison, caribou, Sitka black-tailed deer, elk, mountain goat, moose, muskox, Dall's sheep, wolf, and wolverine.

* * * * *

Cub bear means a brown (grizzly) bear in its first or second year of life, or a black bear (including the cinnamon and blue phases) in its first year of life.

* * * * *

Fur animal means a classification of animals subject to taking with a hunting license, consisting of beaver, coyote, arctic fox, red fox, lynx, flying squirrel, ground squirrel, or red squirrel that have not been domestically raised.

Furbearer means a beaver, coyote, arctic fox, red fox, lynx, marten, mink, least weasel, short-tailed weasel, muskrat, land otter, red squirrel, flying squirrel, ground squirrel, Alaskan marmot, hoary marmot, woodchuck, wolf and wolverine.

* * * * *

Trapping means taking furbearers under a trapping license.

* * * * *

■ 3. In § 13.40, revise the section heading and paragraphs (d) and (e) to read as follows:

§ 13.40 Taking of fish.

* * * * *

(d) *Use of native species as bait.* Use of species native to Alaska as bait for fishing is allowed in accordance with non-conflicting State law and regulations.

(e) *Closures and restrictions.* The Superintendent may prohibit or restrict the non-subsistence taking of fish in accordance with the provisions of § 13.50.

■ 4. Add § 13.42 to read as follows:

§ 13.42 Taking of wildlife in national preserves.

(a) Hunting and trapping are allowed in national preserves in accordance with applicable Federal and non-conflicting State law and regulation.

(b) Violating a provision of either Federal or non-conflicting State law or regulation is prohibited.

(c) Engaging in trapping activities as the employee of another person is prohibited.

(d) It shall be unlawful for a person having been airborne to use a firearm or any other weapon to take or assist in taking any species of bear, caribou, Sitka black-tailed deer, elk, coyote, arctic and red fox, mountain goat, moose, Dall sheep, lynx, bison, musk ox, wolf and wolverine until after 3 a.m. on the day following the day in which the flying occurred. This prohibition does not apply to flights on regularly scheduled commercial airlines between regularly maintained public airports.

(e) Persons transporting wildlife through park areas must identify themselves and the location where the wildlife was taken when requested by NPS law enforcement personnel.

(f) State of Alaska management actions or laws or regulations that authorize taking of wildlife are not adopted in park areas if they are related to predator reduction efforts. Predator reduction efforts are those with the intent or potential to alter or manipulate natural predator-prey dynamics and associated natural ecological processes, in order to increase harvest of ungulates by humans.

(1) The Regional Director will compile a list updated at least annually of State laws and regulations not adopted under this paragraph (f).

(2) Taking of wildlife, hunting or trapping activities, or management actions identified in this paragraph (f) are prohibited. Notice of activities prohibited under this paragraph (f)(2) will be provided in accordance with § 13.50(f).

(g) This paragraph applies to the taking of wildlife in park areas administered as national preserves except for subsistence uses by local rural residents pursuant to applicable Federal law and regulation. As of January 1, 2016, the following are prohibited:

Prohibited acts	Any exceptions?
(1) Shooting from, on, or across a park road or highway	None.
(2) Using any poison or other substance that kills or temporarily incapacitates wildlife.	None.
(3) Taking wildlife from an aircraft, off-road vehicle, motorboat, motor vehicle, or snowmachine.	If the motor has been completely shut off and progress from the motor's power has ceased.
(4) Using an aircraft, snowmachine, off-road vehicle, motorboat, or other motor vehicle to harass wildlife, including chasing, driving, herding, molesting, or otherwise disturbing wildlife.	None.
(5) Taking big game while the animal is swimming	None.
(6) Using a machine gun, a set gun, or a shotgun larger than 10 gauge	None.
(7) Using the aid of a pit, fire, artificial salt lick, explosive, expanding gas arrow, bomb, smoke, chemical, or a conventional steel trap with an inside jaw spread over nine inches.	Killer style traps with an inside jaw spread less than 13 inches may be used for trapping, except to take any species of bear or ungulate.
(8) Using any electronic device to take, harass, chase, drive, herd, or molest wildlife, including but not limited to: artificial light; laser sights; electronically enhanced night vision scope; any device that has been airborne, controlled remotely, and used to spot or locate game with the use of a camera, video, or other sensing device; radio or satellite communication; cellular or satellite telephone; or motion detector.	(i) Rangefinders may be used. (ii) Electronic calls may be used for game animals except moose. (iii) Artificial light may be used for the purpose of taking furbearers under a trapping license during an open season from Nov. 1 through March 31 where authorized by the State. (iv) Artificial light may be used by a tracking dog handler with one leashed dog to aid in tracking and dispatching a wounded big game animal. (v) Electronic devices approved in writing by the Regional Director.
(9) Using snares, nets, or traps to take any species of bear or ungulate	None.
(10) Using bait	Using bait to trap furbearers.
(11) Taking big game with the aid or use of a dog	Leashed dog for tracking wounded big game.
(12) Taking wolves and coyotes from May 1 through August 9	None.
(13) Taking cub bears or female bears with cubs	None.
(14) Taking a fur animal or furbearer by disturbing or destroying a den	Muskrat pushups or feeding houses.

(h) The Superintendent may prohibit or restrict the non-subsistence taking of wildlife in accordance with the provisions of § 13.50.

(i) A person may not intentionally obstruct or hinder another person's lawful hunting or trapping by:

(1) Placing oneself in a location in which human presence may alter the behavior of the game that another person is attempting to take or the imminent feasibility of taking game by another person; or

(2) Creating a visual, aural, olfactory, or physical stimulus in order to alter the behavior of the game that another person is attempting to take.

■ 5. Revise § 13.50 to read as follows:

§ 13.50 Closure and restriction procedures.

(a) *Applicability and authority.* The Superintendent will follow the provisions of this section to close an area or restrict an activity, or terminate or relax a closure or restriction, in NPS areas in Alaska.

(b) *Factors.* In determining whether to close an area or restrict an activity, or whether to terminate or relax a closure or restriction, the Superintendent must ensure that the activity or area is managed in a manner compatible with the purposes for which the park area was established. The Superintendent's decision under this paragraph must therefore be guided by factors such as public health and safety, resource protection, protection of cultural or scientific values, subsistence uses, conservation of endangered or threatened species, and other management considerations.

(c) *Rulemaking requirements.* This paragraph applies only to a closure or restriction, or the termination or relaxation of such, which is of a nature, magnitude and duration that will result in a significant alteration in the public use pattern of the area; adversely affect the area's natural, aesthetic, scenic, or cultural values; or require a long-term modification in the resource management objectives of the area. Except in emergency situations, the closure or restriction, or the termination or relaxation of such, must be published as a rulemaking in the **Federal Register**.

(d) *Written determination.* Except in emergency situations, prior to implementing or terminating a closure or restriction, the superintendent shall prepare a written determination justifying the action. That determination shall set forth the reasons the closure or restriction authorized by paragraph (a) of this section has been established. This determination will be posted on the NPS Web site at *www.nps.gov.*

(e) *Restrictions on taking fish or wildlife.* (1) Except in emergencies, the NPS will consult with the State agency having responsibility over fishing, hunting, or trapping and provide an opportunity for public comment, including one or more public meetings near the affected NPS unit, prior to implementing a closure or restriction on taking fish or wildlife.

(2) Emergency closures or restrictions may not exceed a period of 60 days and may not be extended without following the nonemergency procedures of this section.

(f) *Notice.* A list of closures and restrictions will be compiled in writing and updated annually. The list will be posted on the NPS Web site at *www.nps.gov* and made available at park headquarters. Additional means of notice reasonably likely to inform residents in the affected vicinity will also be provided where available, such as:

(1) Publication in a newspaper of general circulation in the State or in local newspapers;

(2) Use of electronic media, such as the internet and email lists;

(3) Radio broadcast; or

(4) Posting of signs in the local vicinity.

(g) Violating a closure or restriction is prohibited.

§ 13.400 [Amended]

■ 6. In § 13.400, remove paragraph (e) and redesignate paragraph (f) as new paragraph (e).

■ 7. Revise § 13.470 to read as follows:

§ 13.470 Subsistence fishing.

Fish may be taken by local rural residents for subsistence uses in park areas where subsistence uses are allowed in compliance with applicable Federal law and regulation, including the provisions of §§ 2.3 and 13.40 of this chapter. Local rural residents in park areas where subsistence uses are allowed may fish with a net, seine, trap, or spear; or use native species as bait, where permitted by applicable Federal law and regulation.

■ 8. Revise § 13.480 to read as follows:

§ 13.480 Subsistence hunting and trapping.

Local rural residents may hunt and trap wildlife for subsistence uses in park areas where subsistence uses are allowed in compliance with this chapter and 50 CFR part 100.

■ 9. In § 13.490, revise paragraph (a) to read as follows:

§ 13.490 Closures and restrictions to subsistence uses of fish and wildlife.

(a) The Superintendent may temporarily restrict a subsistence activity or close all or part of a park area to subsistence uses of a fish or wildlife population after consultation with the State and the Federal Subsistence Board in accordance with the provisions of this section. The Superintendent may make a temporary closure or restriction notwithstanding any other provision of this part, and only if the following conditions are met:

(1) The restriction or closure must be necessary for reasons of public safety, administration, or to ensure the continued viability of the fish or wildlife population;

(2) Except in emergencies, the Superintendent must provide public notice and hold a public hearing near the affected NPS unit;

(3) The restriction or closure may last only so long as reasonably necessary to achieve the purposes of the closure.

* * * * *

Dated: September 9, 2015.

Michael Bean,

Principal Deputy Assistant Secretary for Fish and Wildlife and Parks.

[FR Doc. 2015–26813 Filed 10–22–15; 8:45 am]

BILLING CODE 4310–EJ–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 52

[EPA–R04–OAR–2015–0337; FRL–9936–05–Region 4]

Approval and Promulgation of Implementation Plans; Florida; Regional Haze Plan Amendment—Lakeland Electric C.D. McIntosh

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: The Environmental Protection Agency (EPA) is finalizing approval of the State of Florida's March 10, 2015, State Implementation Plan (SIP) revision, submitted by the Florida Department of Environmental Protection (FDEP). This submittal fulfills Florida's commitment to EPA to provide a regional haze SIP revision with a Best Available Retrofit Technology (BART) nitrogen oxides (NOx) emissions limit for Unit 1 at the Lakeland Electric—C.D. McIntosh Power Plant (McIntosh) reflecting best operating practices for good combustion. States are required to address the BART provisions of the Clean Air Act (CAA or Act) and EPA's

regional haze regulations as part of a program to prevent any future and remedy any existing anthropogenic impairment of visibility in mandatory Class I areas (national parks and wilderness areas) caused by emissions of air pollutants from numerous sources located over a wide geographic area (also referred to as the ''regional haze program'') and to assure reasonable progress toward the national goal of achieving natural visibility conditions in Class I areas. In this action, EPA is approving the BART NOx emissions limit for Unit 1 at McIntosh into the Florida SIP.

DATES: This rule is effective November 23, 2015.

ADDRESSES: EPA has established a docket for this action under Docket Identification No. EPA–R04–OAR–2015–0337. All documents in the docket are listed on the *www.regulations.gov* Web site. Although listed in the index, some information may not be publicly available, *i.e.,* Confidential Business Information or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available either electronically through *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: Michele Notarianni, 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. Ms. Notarianni can be reached by phone at (404) 562–9031 or via electronic mail at *notarianni.michele@epa.gov.*

SUPPLEMENTARY INFORMATION:

I. Background

On December 10, 2012, EPA proposed to approve the BART and reasonable progress determinations for a number of EGUs in Florida as part of Florida's regional haze SIP. *See* 77 FR 73369. In that action, EPA proposed approval of Florida's BART determination for emissions Units 1 and 2 at McIntosh found subject to BART. On August 29, 2013, EPA issued a final, full approval of Florida's regional haze SIP. *See* 78 FR 53250. In that final action, EPA approved the BART determination for the McIntosh facility, including the determination that the existing level of control for NOx at Unit 1, best operating practices for good combustion, is the NOx BART control for Unit 1. *See* 78 FR 53263. As described in the August 29, 2013, final action, FDEP submitted a letter to EPA dated July 30, 2013, in which the State committed to provide EPA with a regional haze SIP revision no later than March 19, 2015, the deadline for the State's five-year regional haze periodic progress report SIP, that would include a NOx BART emissions limit for Unit 1 reflecting best operating practices for good combustion. FDEP also committed to modify the title V permit for McIntosh to include this new limit.

To fulfill its commitment in accordance with the July 30, 2013 letter, the State of Florida submitted a SIP revision dated March 10, 2015, revising the State's regional haze SIP to include a NOx BART emissions limit for McIntosh Unit 1 and a construction permit (FDEP Permit No. 1050004–034–AC) dated April 30, 2014, for Unit 1 containing this limit. The permit contains supporting conditions (*e.g.,* monitoring requirements) and a condition specifying a schedule for McIntosh to apply for a revision to its title V permit to reflect the new permit conditions.

In a notice of proposed rulemaking (NPR) published on August 20, 2015, EPA proposed to approve Florida's March 10, 2015, regional haze SIP revision fulfilling the State's July 20, 2013, commitment to provide EPA with a SIP revision containing a NOx BART emissions limit for McIntosh Unit 1 reflecting best operating practices for good combustion and conditions to modify the title V permit to incorporate this limit. *See* 80 FR 50591. The details of Florida's submittal and the rationale for EPA's actions are explained in the NPR. Comments on the proposed rulemaking were due on or before September 21, 2015. No adverse comments were received.

II. Final Action

EPA is finalizing approval of the State of Florida's March 10, 2015, SIP revision and revising the regional haze SIP to include the NOx BART emissions limit for Unit 1 and the April 30, 2014, construction permit containing this limit. EPA is approving these changes to the Florida SIP because the submission meets the applicable regional haze requirements as set forth in the CAA and in EPA's regional haze regulations and the applicable requirements of section 110 of the CAA.

III. 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 approves 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.

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 December 22, 2015. Filing a petition for reconsideration by the Administrator of this final rule does not affect the finality of this action 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 may not be challenged later in proceedings to enforce its requirements. *See* section 307(b)(2).

List of Subjects in 40 CFR Part 52

Environmental protection, Air pollution control, Carbon monoxide, Incorporation by reference, Intergovernmental relations, Lead, Nitrogen dioxide, Ozone, Particulate matter, Reporting and recordkeeping requirements, Sulfur oxides, Volatile organic compounds.

Dated: October 8, 2015.

Heather McTeer Toney,

Regional Administrator, Region 4.

40 CFR part 52 is amended as follows:

PART 52—APPROVAL AND PROMULGATION OF IMPLEMENTATION PLANS

■ 1. The authority citation for part 52 continues to read as follows:

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

Subpart K—Florida

■ 2. Section 52.520(e) is amended by adding an entry for ''Regional Haze Plan Amendment 3'' at the end of the table to read as follows:

§ 52.520 Identification of plan.

* * * * *

(e) * * *

EPA-APPROVED FLORIDA NON-REGULATORY PROVISIONS

Provision	State effective date	EPA approval date	**Federal Register** notice	Explanation
*	*	*	* *	* *
Regional Haze Plan Amendment 3.	4/30/2014	10/23/2015 [Insert **Federal Register** citation].	[Insert **Federal Register** citation].	Establishes NO_X BART emissions limit for Unit 1 at the Lakeland Electric—C.D. McIntosh Power Plant and includes FDEP Permit No. 1050004–034–AC.

[FR Doc. 2015–26935 Filed 10–22–15; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 52

[EPA–R10–OAR–2014–0562: FRL–9935–48–Region 10]

Approval and Promulgation of Implementation Plans; Oregon: Lane Regional Air Protection Agency Open Burning Rules and Oregon Department of Environmental Quality Enforcement Procedures

AGENCY: Environmental Protection Agency.

ACTION: Direct final rule.

SUMMARY: The Environmental Protection Agency (EPA) is approving into Oregon's State Implementation Plan (SIP) a submittal from the Oregon Department of Environmental Quality (ODEQ) dated July 7, 2014, containing revisions to the Lane Regional Air Protection Agency's (LRAPA) open burning rules adopted on March 14, 2008. The revised LRAPA open burning rules make clarifications and provide for additional controls of open burning activities in Lane County, would reduce particulate emissions in Lane County, and would strengthen Oregon's SIP. The EPA is also approving a submittal from the ODEQ dated June 30, 2014, to update Oregon Administrative Rules (OAR) that relate to procedures in contested cases (appeals), enforcement procedures, and civil penalties. The EPA is approving most of the submitted provisions because the revisions clarify and strengthen the SIP and are consistent with the Clean Air Act (CAA). The EPA is not approving certain provisions of the submitted rules that do not relate to the requirements for SIPs under section 110 of the CAA. Finally, the EPA is correcting the SIP pursuant to the authority of section 110(k)(6) of the CAA to remove certain provisions previously approved by the EPA that do not relate to the requirements for SIPs under section 110 of the CAA.

DATES: This rule is effective on December 22, 2015, without further notice, unless the EPA receives adverse comment by November 23, 2015. If the EPA receives adverse comment, we will publish a timely withdrawal in the **Federal Register** informing the public that the rule will not take effect.

ADDRESSES: Submit your comments, identified by Docket ID No. EPA–R10–OAR–2014–0562, by any of the following methods:

- *Federal eRulemaking Portal http://www.regulations.gov:* Follow the on-line instructions for submitting comments.
- *Email: R10-Public_Comments@epa.gov.*
- *Mail:* Mr. Keith Rose, EPA Region 10, Office of Air, Waste, and Toxics, AWT–150, 1200 Sixth Avenue, Suite 900, Seattle, WA 98101.
- *Hand Delivery/Courier:* EPA Region 10, 1200 Sixth Avenue, Suite 900, Seattle, WA 98101. Attention: Mr. Keith Rose, Office of Air, Waste, and Toxics, AWT–150. Such deliveries are only

accepted during normal hours of operation, and special arrangements should be made for deliveries of boxed information.

Instructions: Direct your comments to Docket ID No. EPA–R10–OAR–2014–0562. 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 disk or CD–ROM you submit. If the EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, the EPA may not be able to consider your comment. Electronic files should avoid the use of special characters, any form of encryption, and be free of any defects or viruses.

Docket: All documents in the docket are listed in the *http://www.regulations.gov* index. Although listed in the index, some information is not publicly available, *e.g.,* CBI or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy. Publicly available docket materials are available at *http://www.regulations.gov* or at EPA Region 10, Office of Air, Waste, and Toxics, AWT–107, 1200 Sixth Avenue, Seattle, Washington 98101. The EPA requests that 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 to 4:30, excluding Federal holidays.

FOR FURTHER INFORMATION CONTACT: Keith A. Rose at (206) 553–1949, *rose.keith@epa.gov,* or the above EPA, Region 10 address.

SUPPLEMENTARY INFORMATION: Throughout this document whenever ''we,'' ''us,'' or ''our'' are used, it is intended to refer to the EPA.

Table of Contents

I. Introduction

Title I of the CAA specifies the general requirements for states to submit SIPs to attain and maintain the National Ambient Air Quality Standards (NAAQS) and the EPA's actions regarding approval of those SIPs. The EPA received a submittal from the ODEQ on July 7, 2014 requesting that the EPA approve into the Oregon SIP the revisions to the LRAPA open burning rules (title 47) adopted on March 14, 2008. In general, the revised LRAPA open burning rules make clarifications and provide for additional controls of open burning activities in Lane County. The EPA also received a submittal from the ODEQ on June 30, 2014 that updates Oregon Administrative Rules (OAR) Chapter 340, Division 11, Rules of General Applicability and Organization, relating to contested cases (appeals of ODEQ actions) and OAR Chapter 340, Division 12, Enforcement Procedures and Civil Penalties. These divisions apply across all programs implemented by the ODEQ, including the air quality regulations that the EPA has approved into the SIP.

The July 7, 2014 and June 30, 2014 SIP submittals also contain amendments to OAR 340–200–0040. This rule describes the State's procedures for adopting its SIP and references all of the state air regulations that have been adopted by the ODEQ for approval into the SIP (as a matter of state law), whether or not they have yet been submitted to or approved by the EPA.

II. EPA Evaluation of the Submittals

A. LRAPA Title 47, Open Burning (July 7, 2014 Submittal)

LRAPA made numerous revisions throughout title 47, Open Burning. The key substantive changes are discussed below. A more detailed evaluation of the revisions to LRAPA's open burning rules is in the docket for this action. As discussed below, the EPA proposes to find that, overall, the revised rules will provide for additional controls for open burning activities in Lane County, reduce particulate emissions in Lane County, and strengthen Oregon's SIP.

1. Exemptions

LRAPA made several revisions to the types of open burning exempt from regulation and added one new exemption category. Although residential barbequing remains exempt, LRAPA has clarified that certain prohibited materials, such as garbage or plastic, may not be burned as fuel. The exemption for residential fires for recreational purposes has been narrowed by prohibiting the use of yard waste as fuel and prohibiting such fires altogether on yellow and red home wood heating advisory days called by LRAPA in the winter months within the Eugene/Springfield Urban Growth Boundary (ESUGB) and within the city limits of Oakridge. Religious ceremonial fires have been added as a new category of fires exempt from title 47. See LRAPA 47–005–2.C and 47–010 (definition of ''religious ceremonial fires''). LRAPA expects religious ceremonial fires to occur infrequently and the definition requires that such fires be controlled, be ''integral to a religious ceremony or ritual,'' and that prohibited materials not be burned. Given the narrow scope of this exemption, that the exemptions from title 47 have otherwise been narrowed, and that the other revisions to title 47 generally strengthen the prohibitions on open burning, the EPA finds that the new exemption for religious ceremonial fires will not interfere with attainment or maintenance of the NAAQS or any other applicable requirement of the CAA. The EPA therefore approves the revisions to LRAPA 47–005, Exemptions from these Rules.

2. Definitions

The following definitions in LRAPA 47–010 have been revised: Agricultural open burning, commercial wastes, construction wastes, construction open burning, demolition wastes, demolition open burning, Eugene-Springfield Urban Growth Boundary, industrial open burning, and industrial waste. In general, the revisions to these definitions clarify the types of burn and waste categories. For example, through revisions to the definitions of construction waste, demolition waste, and commercial waste, it is now clear that wastes transported offsite are considered commercial waste even if the waste might otherwise meet the definition of construction or demolition waste. Because requirements for the open burning of commercial waste are generally more restrictive, these clarifications make the rules more stringent. These changes to definitions also make clear that materials included in the list of prohibited materials in LRAPA 47–015–1.E cannot be burned even if the material otherwise meets the specified definition. Again, these revisions make the rules more stringent.

Definitions have been added to LRAPA 47–010 for agricultural operation, agricultural waste, bonfire, forest slash open burning, nuisance, recreational fire, religious ceremonial fire, and salvage. The new definition of ''religious ceremonial fire'' is discussed above in Section II.A.1 and the new definition of ''forest slash opening burning'' is discussed in Section II.A.3 below. In general, the other new definitions clarify the meaning of terms previously used in the rules and thus enhance the enforceability of the rules.

Because the revised and new definitions in LRAPA 47–010 either increase the stringency of the rules or provide clarification to enhance enforceability, the EPA approves revisions to LRAPA 47–010 except for the definition of ''nuisance,'' which is discussed in more detail in Section II.A.5 below.

Note that the introductory language in LRAPA 47–010 references title 12 of the LRAPA regulations for additional definitions. Proposed revisions to title 12 were included in a SIP submission that the EPA received on August 28, 2014. The present action does not address those revisions. The EPA will be acting on that submission in a future action.

3. Open Burning Requirements

LRAPA 47–015 contains most of the requirements for open burning, with general requirements to be met for all open burning and specific requirements for residential open burning, construction and demolition open burning, commercial open burning, industrial open burning, and a new category, forest slash open burning.

Requirements for residential open burning have been made more stringent in a number of respects. The ending times for open burns are now set by a LRAPA burning advisory, rather than automatically extending until sunset. All open burning remains prohibited within the city of Eugene, and the prohibition on open burning within the city of Springfield has been expanded so that the burning of woody yard trimmings on lots of a half acre or more is now only allowed between March 1 through June 15 and October 1 through October 31, rather than from October 1 to June 15. The period of allowed residential open burning outside of the Eugene and Springfield city limits but within the ESUGB has similarly been narrowed. The Hazeldell and Siuslaw fire districts have been added to the list of fire districts that must comply with the open burning requirements for fire districts, which include the prohibition on burning construction/demolition debris unless authorized by a letter permit. Therefore, the conditions for open burning in the two newly added fire districts are now more stringent. Finally, a new section restricts residential open burning of woody yard trimmings, leaves and grass in Lane County outside of the affected areas identified in LRAPA 47–015–2.B–F to approved burn days from October 1 through June 15, instead of year around. There have been no substantive changes to the requirements for construction and demolition open burning, commercial open burning, or industrial open burning.

A new section has been added to specifically address forest slash open burning. LRAPA 47–015–6.A confirms that forest slash open burning in areas covered by the Oregon Smoke Management Plan is regulated by the Oregon Department of Forestry under ORS 477.515 and not under LRAPA title 47. Such burning is already specifically exempt from LRAPA title 47 under the current SIP. See LRAPA 47–005–1.D.

LRAPA 47–015–6.B addresses forest slash open burning in Lane County outside of areas covered by the Oregon Smoke Management Plan. Forest slash open burning in such areas is now expressly prohibited within the ESUGB. Forest slash open burning is also prohibited unless authorized by a letter permit under LRAPA 47–020, in the fire districts identified in LRAPA 47–015–2.F and other properties not covered by the Oregon Smoke Management Plan. Maps provided by LRAPA show that there is very limited forest land in Lane County that is not covered by the Smoke Management Plan, and would therefore be covered by the LRAPA forest slash open burning rules.

Any slash burning in Lane County must now be coordinated with the South Cascade and Western Lane districts, and be consistent with slash burning advisories issued by Oregon Department of Forestry. In addition, under LRAPA 47–020–1, letter permits for such forest slash open burning can only be issued on a singly occurring or infrequent basis. According to LRAPA, forest slash open burning was not previously expressly regulated under title 47 prior to 1995. Seen in that light, the regulation of forest slash open burning on land not covered by the Oregon Smoke Management Plan would be an increase in the stringency of the Oregon SIP. The EPA considers the language in LRAPA 47–001 (''all open burning is prohibited in Lane County except as expressly allowed by these rules or if exempted from these rules by Oregon Statute''), which is currently approved in the SIP, however, as potentially prohibiting forest open slash burning on land that is not covered by the Oregon Smoke Management Plan. In that respect, authorizing forest slash open burning through a letter permit under certain conditions could be considered less stringent than the current SIP. In any event, given the many other provisions of this SIP revision that make the SIP more stringent, that only one instance of such open slash burning has been issued a letter permit by LRAPA since 1995, the factors considered by LRAPA and findings LRAPA must make in issuing a letter permit for forest slash open burning in LRAPA 47–020–5 and –6, the EPA concludes that allowing this narrow category of open burning will not interfere with attainment and maintenance of the NAAQS or any other applicable requirement of the CAA. Accordingly, with the exception of LRAPA 47–015–6(B)(5), discussed in Section II.A.5 below, the EPA approves the revisions to LRAPA 47–015, Open Burning Requirements, because the revisions increase the overall stringency of the restrictions on open burning.

4. Letter Permits

LRAPA 47–020 authorizes certain types of open burning under letter permits issued by LRAPA. As discussed in Section II.A.3 above, this section has been amended to add forest slash burning for a single occurrence or on an infrequent basis to the list of the categories of open burning that may be allowed by a letter permit issued by LRAPA. It has also been amended to authorize issuance of letter permits for a bonfire held for a single event. The EPA finds that the potential increase in emissions that would result from these infrequent activities would be de minimis in light of the other restrictions on open burning imposed by the other revisions to title 47 in this SIP submittal.

LRAPA 47–020–5 contains a list of factors to be considered by LRAPA in determining whether to issue a letter permit. This provision has been amended to allow LRAPA to consider as an alternative disposal method whether waste materials can be salvaged.

Because the availability of alternative disposal options mitigates against authorizing open burning under LRAPA's rules, see LRAPA 47–001, expanding the list of what can be considered as an alternative disposal method makes the rules more stringent.

With the exception of certain provisions discussed below in Section II.A.5 that do not relate to the requirements of section 110 of the CAA, the EPA approves the revisions to LRAPA 47–020 because the revisions do not interfere with attainment and maintenance of the NAAQS or any other applicable requirement of the CAA.

5. Summary Table

LRAPA has removed the table is section 47–030, Summary of Seasons, Areas, and Permit Requirements for Open Burning. This table was a summary of the text explaining what type of burning was allowed in each area of Lane County. Removing this table has no impact on the stringency of the rule.

6. Rules Not Approved or Being Removed From the SIP

Title 47 contains several provisions, both previously approved by the EPA into the Oregon SIP, and newly enacted or revised provisions, that relate to nuisance, fire safety, or environmental issues that do not relate to air quality. The EPA's authority to approve SIPs extends to provisions related to attainment and maintenance of the NAAQS and carrying out other specific requirements of section 110 of the CAA. Section 110(k)(6) of the CAA authorizes the EPA, upon a determination that the EPA's action approving, disapproving or promulgating any SIP or plan revision (or any part thereof) was in error, to revise such action as appropriate.

In this action, the EPA is not approving into the SIP and is removing from the SIP the following provisions of title 47 that do not relate to attainment and maintenance of the NAAQS or the other requirements of section 110 the CAA: The definition of ''nuisance'' in LRAPA 47–010; LRAPA 47–015–1.D (currently in the SIP); LRAPA 47–015–1.H; LRAPA 47–015–6.B(5); LRAPA 47–020–3 (currently in the SIP); LRAPA 47–020–9.I; LRAPA 47–020–10 (first sentence currently in the SIP).

B. ODEQ Chapter 340, Divisions 11 and 12 (June 30, 2014 Submittal)

1. Division 11, Rules of General Applicability and Organization

Oregon's June 30, 2014 submittal revises OAR Chapter 340, Division 11, to align with the Oregon Attorney General Model Rules, which address procedures for filing and serving documents in contested cases (appeals of ODEQ actions). These rule revisions were adopted by Oregon on December 11, 2013 and became effective on January 6, 2014. The rules were revised to improve the clarity and completeness of contested case appeals coming before the Environmental Quality Commission.

Division 11 provides authority needed for implementing the SIP and is consistent with the CAA requirements for the issuance of permits and enforcement authority. The EPA is therefore approving the revisions to Division 11 submitted by the ODEQ, subject to the qualifications discussed below in Section III.

2. Division 12, Enforcement Procedures and Civil Penalties

Division 12 contains enforcement procedures and civil penalty provisions that apply across all programs implemented by the ODEQ, including the air quality regulations that the EPA has approved into the SIP. Division 12 provides the authority and procedures under which the ODEQ notifies regulated entities of violations, determines the appropriate penalties for violations, and assesses penalties for such violations. The revisions to Division 12 made by the ODEQ implement legislative increases in statutory maximum penalties, align violation classifications and magnitudes with ODEQ program priorities, provide greater mitigating credit for correcting violations, and make minor housekeeping changes.

The EPA has reviewed the revisions to OAR Chapter 340, Division 12 and finds that these rules continue to provide the ODEQ with adequate authority for enforcing the SIP as required by section 110 of the Clean Air Act and 40 CFR 50.230(b). Importantly, OAR 340–012–0160(1) gives the ODEQ the discretion to increase a base penalty to that derived using the next highest penalty matrix value and OAR 340–012–0160(4) gives the ODEQ the discretion to deviate from the penalty matrices and assess penalties of $25,000 per day, per violation based on the facts and circumstances of the individual case. The EPA therefore approves into the SIP the revisions to Division 12 submitted by the ODEQ, subject to the qualifications discussed below in Section III.

III. Final Action

The EPA is taking the following action on the revisions to LRAPA title 47, Open Burning, adopted on May 14, 2008, and submitted to the EPA by the ODEQ on July 7, 2014. We approve the revisions to the following sections except as identified below: 47–001, General Policy; 47–005, Exemptions from These Rules; 47–010, Definitions; 47–015, Open Burning Requirements; and 47–020, Letter Permits. As discussed in Section II.A.5 above, because the EPA's authority to approve SIPs extends to provisions related to attainment and maintenance of the NAAQS and carrying out other specific requirements of section 110 of the CAA, we are not approving into the SIP and are removing from the SIP under the authority of CAA section 110(k)(6) the following provisions: The definition of ''nuisance'' in LRAPA 47–010; LRAPA 47–015–1.D (currently in the SIP); LRAPA 47–015–1.H; LRAPA 47–015–6.B(5); LRAPA 47–020–3 (currently in the SIP); LRAPA 47–020–9.I; LRAPA 47–020–10 (first sentence currently in the SIP).

The EPA also approves revisions to OAR Chapter 340, Division 11, adopted on December 11, 2013 and submitted by the ODEQ on June 30, 2014. The EPA is approving this division, however, only to the extent it relates to implementation of requirements contained in the Oregon SIP. The EPA is not incorporating these rules by reference into the Code of Federal Regulations, however, because the EPA relies on its independent administrative and enforcement procedures under the CAA.

The EPA also approves revisions to OAR Chapter 340, Division 12, adopted on December 11, 2013 and submitted by the ODEQ on June 30, 2014, except for the following provisions that do not relate to air emissions and were not submitted by the ODEQ for approval: OAR 340–012–0027,[1] –0055, –0060, –0065, –0066, –0067, –0068, –0071, –0072, –0073, –0074, –0079, –0081, –0082, –0083, –0097. In addition, the EPA is approving the remaining sections in Chapter 340, Division 12, only to the extent they relate to enforcement of requirements contained in the Oregon SIP. Again, the EPA is not incorporating these rules by reference into the Code of Federal Regulations, however, because the EPA relies on its independent enforcement procedures and penalty provisions in bringing enforcement actions and assessing penalties under the CAA.

The EPA is not approving the revisions to OAR 340–200–0040 in these SIP submittals because these provisions address state SIP adoption procedures and because the Federally-approved SIP consists only of regulations and other requirements that have been submitted by the ODEQ and approved by the EPA.

[1] No such citation appears in Division 12, but these provisions have not been submitted by the ODEQ in any event.

IV. Incorporation by Reference

In this rule, the EPA is finalizing regulatory text that includes incorporation by reference. In accordance with requirements of 1 CFR 51.5, the EPA is incorporating by reference the ODEQ regulations described in the amendments to 40 CFR part 52 set forth below. 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).

V. Statutory and Executive Orders Reviews

Under the Clean Air Act, the Administrator is required to approve a SIP submission that complies with the provisions of the Act and applicable Federal regulations. 42 U.S.C. 7410(k); 40 CFR 52.02(a). Thus, in reviewing SIP submissions, the EPA's role is to approve state choices, provided that they meet the criteria of the Clean Air Act. Accordingly, this action merely approves 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 Clean Air Act; and
- does not provide the 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 the 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).

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. The 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 Clean Air Act, petitions for judicial review of this action must be filed in the United States Court of Appeals for the appropriate circuit by December 22, 2015. Filing a petition for reconsideration by the Administrator of this final rule does not affect the finality of this action 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. Parties with objections to this direct final rule are encouraged to file a comment in response to the parallel notice of proposed rulemaking for this action published in the proposed rules section of today's **Federal Register**, rather than file an immediate petition for judicial review of this direct final rule, so that the EPA can withdraw this direct final rule and address the comment in the proposed rulemaking. This action may not be challenged later in proceedings to enforce its requirements. (See section 307(b)(2).)

List of Subjects in 40 CFR Part 52

Environmental protection, Air pollution control, Intergovernmental relations, Incorporation by reference, Particulate matter, Reporting, and recordkeeping requirements.

Dated: September 25, 2015.

Michelle L. Pirzadeh,

Acting Regional Administrator, Region 10.

For the reasons stated in the preamble, 40 CFR part 52 is amended as follows:

PART 52—APPROVAL AND PROMULGATION OF IMPLEMENTATION PLANS

■ 1. The authority citation for Part 52 continues to read as follows:

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

Subpart MM—Oregon

■ 2. Section 52.1970 is amended:

■ a. In paragraph (c) Table 4—EPA Approved Lane Regional Air Protection Agency (LRAPA) Rules for Oregon by:

■ i. Revising entries 47–001, 47–005, 47–010, 47–015, and 47–020.

■ ii. Removing the entry 47–030.

■ b. In paragraph (e) table titled ''Oregon Administrative Rules Approved, But Not Incorporated By Reference'' by:

■ i. Revising entry 011–0005.

■ ii. Adding entries 011–0010, 011–0024, 011–0029, 011–0046, 011–0053, 011–0061, 011–0310, 011–0330, 011–0340, 011–0360, 011–0370, 011–0380, 011–0390, and 011–0500 in numerical order.

■ iii. Revising entries 011–0510 and 011–0515.

■ iv. Adding entries 011–0520, 011–0525, 011–0530, 011–0535, 011–0540, 011–0545, 011–0550, 011–0555, 011–0565, and 011–0570 in numerical order.

■ v. Revising entries 011–0573 and 011–0575.

■ vi. Adding entries 011–0580 and 011–0585 in numerical order.

■ vii. Revising entries 012–0026, 012–0028, 012–0030, 012–0038, 012–0041, 012–0045, 012–0053, 012–0054, 012–0130, 012–0135, 012–0140, 012–0145, 012–0150, 012–0155, 012–0160, 012–0162, 012–0165, and 012–0170.

The revisions and additions read as follows:

§ 52.1970 Identification of plan.

* * * * *

(c) * * *

TABLE 4—EPA APPROVED LANE REGIONAL AIR PROTECTION AGENCY (LRAPA) RULES FOR OREGON

LRAPA citation	Title/subject	State effective date	EPA approval date	Explanations
* * *	* *	*	*	*
Title 47—Rules for Open Outdoor Burning				
47–001	General Policy	3/14/2008	10/23/2015, [Insert **Federal Register** citation].	
47–005	Exemptions from these Rules	3/14/2008	10/23/2015, [Insert **Federal Register** citation].	
47–010	Definitions	3/14/2008	10/23/2015, [Insert **Federal Register** citation].	Except the definition of "nuisance".
47–015	Open Burning Requirements	3/14/2008	10/23/2015, [Insert **Federal Register** citation].	Except 1.D, 1.H, and 6.B(5).
47–020	Letter Permits	3/14/2008	10/23/2015, [Insert **Federal Register** citation].	Except 3, 9.I, and 10.
* * *	* *	*	*	*

* * * * *

(e) EPA Approved Nonregulatory provisions and Quasi-Regulatory Measures.

OREGON ADMINISTRATIVE RULES, APPROVED BUT NOT INCORPORATED BY REFERENCE

State citation	Title/subject	State effective date	EPA approval date	Explanations
Division 11—Rules of General Applicability and Organization				
011–0005	Definitions	1/6/2014	10/23/2015, [Insert **Federal Register** citation].	
011–0010	Notice of Rulemaking	1/6/2014	10/23/2015, [Insert **Federal Register** citation].	
011–0024	Rulemaking Process	1/6/2014	10/23/2015, [Insert **Federal Register** citation].	
011–0029	Policy on Disclosure of the Relationship Between Proposed Rules and Federal Requirements.	1/6/2014	10/23/2015, [Insert **Federal Register** citation].	
011–0046	Petition to Promulgate, Amend, or Repeal Rule: Content of Petition, Filing or Petition.	1/6/2014	10/23/2015, [Insert **Federal Register** citation].	
011–0053	Periodic Rule Review	1/6/2014	10/23/2015, [Insert **Federal Register** citation].	
011–0061	Declaratory Ruling: Institution of Proceedings, Consideration of Petition and Disposition of Petition.	1/6/2014	10/23/2015, [Insert **Federal Register** citation].	
011–0310	Purpose	1/6/2014	10/23/2015, [Insert **Federal Register** citation].	
011–0330	Requests for Review or to Obtain Copies of Public Records.	1/6/2014	10/23/2015, [Insert **Federal Register** citation].	
011–0340	Costs for Record Review and Copying.	1/6/2014	10/23/2015, [Insert **Federal Register** citation].	
011–0360	Collecting Fees	1/6/2014	10/23/2015, [Insert **Federal Register** citation].	
011–0370	Certification of Copies of Records	1/6/2014	10/23/2015, [Insert **Federal Register** citation].	
011–0380	Fee Waivers and Reductions	1/6/2014	10/23/2015, [Insert **Federal Register** citation].	
011–0390	Exempt Records	1/6/2014	10/23/2015, [Insert **Federal Register** citation].	
011–0500	Contested Case Proceedings Generally.	1/6/2014	10/23/2015, [Insert **Federal Register** citation].	
011–0510	Agency Representation by Environmental Law Specialist.	1/6/2014	10/23/2015, [Insert **Federal Register** citation].	

OREGON ADMINISTRATIVE RULES, APPROVED BUT NOT INCORPORATED BY REFERENCE—Continued

State citation	Title/subject	State effective date	EPA approval date	Explanations
011–0515	Authorized Representative of a Participant other than a Natural Person in a Contested Case Hearing.	1/6/2014	10/23/2015, [Insert **Federal Register** citation].	
011–0520	Liability for the Acts of a Person's Employees.	1/6/2014	10/23/2015, [Insert **Federal Register** citation].	
011–0525	Service and Filing of Documents	1/6/2014	10/23/2015, [Insert **Federal Register** citation].	
011–0530	Requests for Hearing	1/6/2014	10/23/2015, [Insert **Federal Register** citation].	
011–0535	Final Orders by Default	1/6/2014	10/23/2015, [Insert **Federal Register** citation].	
011–0540	Consolidation or Bifurcation of Contested Case Hearings.	1/6/2014	10/23/2015, [Insert **Federal Register** citation].	
011–0545	Burden and Standard of Proof in Contested Case Hearings; DEQ Interpretation of Rules and Statutory Terms.	1/6/2014	10/23/2015, [Insert **Federal Register** citation].	
011–0550	Discovery	1/6/2014	10/23/2015, [Insert **Federal Register** citation].	
011–0555	Subpoenas	1/6/2014	10/23/2015, [Insert **Federal Register** citation].	
011–0565	Immediate Review	1/6/2014	10/23/2015, [Insert **Federal Register** citation].	
011–0570	Permissible Scope of Hearing	1/6/2014	10/23/2015, [Insert **Federal Register** citation].	
011–0573	Proposed Orders in Contested Cases.	1/6/2014	10/23/2015, [Insert **Federal Register** citation].	
011–0575	Review of Proposed Orders in Contested Cases.	1/6/2014	10/23/2015, [Insert **Federal Register** citation].	
011–0580	Petitions for Reconsideration or Rehearing.	1/6/2014	10/23/2015, [Insert **Federal Register** citation].	
011–0585	Petitions for a Stay of the Effect of a Final Order.	1/6/2014	10/23/2015, [Insert **Federal Register** citation].	
	Division 12—Enforcement Procedure and Civil Penalties			
012–0026	Policy	1/6/2014	10/23/2015, [Insert **Federal Register** citation].	
012–0028	Scope of Applicability	1/6/2014	10/23/2015, [Insert **Federal Register** citation].	
012–0030	Definitions	1/6/2014	10/23/2015, [Insert **Federal Register** citation].	
012–0038	Warning Letters, Pre-Enforcement Notices and Notices of Permit Violation.	1/6/2014	10/23/2015, [Insert **Federal Register** citation].	
012–0041	Formal Enforcement Actions	1/6/2014	10/23/2015, [Insert **Federal Register** citation].	
012–0045	Civil Penalty Determination Procedure.	1/6/2014	10/23/2015, [Insert **Federal Register** citation].	
012–0053	Classification of Violations that Apply to all Programs.	1/6/2014	10/23/2015, [Insert **Federal Register** citation].	
012–0054	Air Quality Classification of Violations.	1/6/2014	10/23/2015, [Insert **Federal Register** citation].	
012–0130	Determination of Violation Magnitude.	1/6/2014	10/23/2015, [Insert **Federal Register** citation].	
012–0135	Selected Magnitude Categories	1/6/2014	10/23/2015, [Insert **Federal Register** citation].	
012–0140	Determination of Base Penalty	1/6/2014	10/23/2015, [Insert **Federal Register** citation].	
012–0145	Determination of Aggravating or Mitigating Factors.	1/6/2014	10/23/2015, [Insert **Federal Register** citation].	
012–0150	Determination of Economic Benefit	1/6/2014	10/23/2015, [Insert **Federal Register** citation].	
012–0155	Additional or Alternate Civil Penalties.	1/6/2014	10/23/2015, [Insert **Federal Register** citation].	
012–0160	DEQ Discretion Regarding Penalty Assessment.	1/6/2014	10/23/2015, [Insert **Federal Register** citation].	
012–0162	Inability to Pay the Penalty	1/6/2014	10/23/2015, [Insert **Federal Register** citation].	

OREGON ADMINISTRATIVE RULES, APPROVED BUT NOT INCORPORATED BY REFERENCE—Continued

State citation	Title/subject	State effective date	EPA approval date	Explanations
012–0165	Stipulated Penalties	1/6/2014	10/23/2015, [Insert **Federal Register** citation].	
012–0170	Compromise or Settlement of Civil Penalty by DEQ.	1/6/2014	10/23/2015, [Insert **Federal Register** citation].	

* * * * *

[FR Doc. 2015–26159 Filed 10–22–15; 8:45 am]

BILLING CODE 6560–50–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Indian Health Service

42 CFR Part 137

Change of Address for the Interior Board of Indian Appeals

AGENCY: Indian Health Service, Health and Human Services.

ACTION: Final rule.

SUMMARY: The Department of Health and Human Services (HHS or the Department) is revising its regulations governing administrative appeals to reflect a change of address for the Interior Board of Indian Appeals (IBIA). The IBIA moved to a new address at 801 North Quincy St., Suite 300, Arlington, VA 22203 effective February 11, 2002.

DATES: This rule is effective October 23, 2015.

FOR FURTHER INFORMATION CONTACT: Carl Mitchell, Acting Director, Division of Regulatory Affairs, Indian Health Service, 801 Thompson Avenue, Rockville, Maryland 20852, Telephone: (301) 443–1116.

SUPPLEMENTARY INFORMATION:

I. Background

Through a two-person panel of administrative judges, the Interior Board of Indian Appeals (IBIA) has the authority to consider appeals from decisions of agency officials and administrative law judges in cases under the Indian Self-Determination and Education Assistance Act (ISDEAA). Located within the Department of Interior's Office of Hearings and Appeals (OHA), IBIA is separate and independent from the Bureau of Indian Affairs (BIA) and the Assistant Secretary—Indian Affairs.

Effective February 11, 2002, the IBIA was relocated to 801 North Quincy Street, Arlington, Virginia. To avoid confusion with appeals, HHS is updating its administrative appeals regulations to reflect the IBIA's new street address.

II. Procedural Requirements

A. Determination To Issue Final Rule Effective in Less Than 30 Days

The Department has determined that the public notice and comment provisions of the Administrative Procedure Act, 5 U.S.C. 553(b), do not apply to this rulemaking because the changes being made relate solely to matters of agency organization, procedure, and practice. It, therefore, satisfies the exemption from notice and comment rulemaking in 5 U.S.C. 553(b)(A).

Moreover, the Department has determined that there is good cause to waive the requirement of publication 30 days in advance of the rule's effective date under 5 U.S.C. 553(d). The error in the IBIA's location could cause misdirection of appeals. Thus, if the changes in this rule were to become effective 30 days after publication, it could cause further delays in processing appeals. Because an earlier effective date benefits the public, there is good cause for making this rule effective in less than 30 days, as permitted by 5 U.S.C. 553(d)(3).

B. Review Under Procedural Statutes and Executive Orders

The Department has reviewed this rule under the following statutes and executive orders governing rulemaking procedures: The Unfunded Mandates Reform Act of 1995, 2 U.S.C. 1501 *et seq.;* the Regulatory Flexibility Act, 5 U.S.C. 601 *et seq.;* the Small Business Regulatory Enforcement Fairness Act of 1996, 5 U.S.C. 801 *et seq.;* the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.;* the National Environmental Policy Act of 1969, 42 U.S.C. 4321 *et seq.;* Executive Order 12630 (Takings); Executive Order 12866 (Regulatory Planning and Review); Executive Order 12988 (Civil Justice Reform); Executive Order 13132 (Federalism); Executive Order 13175 (Tribal Consultation); and Executive Order 13211 (Energy Impacts). The Department has determined that this rule does not trigger any of the procedural requirements of those statutes and executive orders, since this rule merely changes the street address for the IBIA.

Dated: August 17, 2015.

Robert G. McSwain,

Deputy Director, Indian Health Service.

Approved: October 9, 2015.

Sylvia M. Burwell,

Secretary, Health and Human Services.

For the reasons set forth in the preamble, the Department, through the Indian Health Service amends subpart P of title 42 of the Code of Federal Regulations part 137 to read as follows:

PART 137 [AMENDED]

■ 1. The authority citation for part 137 continues to read as follows:

Authority: 25 U.S.C. 458 *et seq.*

§ 137.418 [Amended]

■ 2. In § 137.418, revise ''4015 Wilson Boulevard, Arlington, VA 22203'' to read ''801 North Quincy St., Suite 300, Arlington, VA 22203''.

§ 137.423 [Amended]

■ 3. In § 137.423, revise ''4015 Wilson Boulevard, Arlington, VA 22203'' to read ''801 North Quincy St., Suite 300, Arlington, VA 22203''.

§ 137.425 [Amended]

■ 4. In § 137.425, in paragraph (b), revise ''4015 Wilson Boulevard, Arlington, VA 22203'' to read ''801 North Quincy St., Suite 300, Arlington, VA 22203''.

§ 137.440 [Amended]

■ 5. In § 137.440, in paragraph (b), revise ''4015 Wilson Boulevard, Arlington, VA 22203'' to read ''801 North Quincy St., Suite 300, Arlington, VA 22203''.

[FR Doc. 2015–27025 Filed 10–22–15; 8:45 am]

BILLING CODE 4165–16–P

DEPARTMENT OF HOMELAND SECURITY

Federal Emergency Management Agency

44 CFR Part 64

[Docket ID FEMA–2015–0001; Internal Agency Docket No. FEMA–8405]

Suspension of Community Eligibility

Correction

In rule document 2015–26449 beginning on page 63130 in the issue of Monday, October 19, 2015, make the following correction:

§ 64.6 [Corrected]

On page 63131, in the table, in the first column, in the Region VII entry ''Kansas: 23 Hanover, City of, Washington County'' should read ''Kansas: Hanover, City of, Washington County''.

[FR Doc. C1–2015–26449 Filed 10–22–15; 8:45 am]

BILLING CODE 1505–01–D

FEDERAL COMMUNICATIONS COMMISSION

47 CFR Part 73

[MB Docket No. 14–226; FCC 15–118]

Broadcast Licensee-Conducted Contests

AGENCY: Federal Communications Commission.

ACTION: Final rule.

SUMMARY: In this document, the Federal Communications Commission (''Commission'') amends the portion of its rules known as the ''Contest Rule'' to permit broadcast licensees to comply with their obligation to disclose material contest terms either by broadcasting those terms or by making them available in writing on a publicly accessible Internet Web site. In particular, the Commission amends the Contest Rule to allow licensees to satisfy their disclosure obligation by posting material contest terms on the station's Web site, the licensee's Web site, or, if neither the individual station nor the licensee has its own Web site, any Internet Web site that is readily accessible to the public. The Commission also adopts requirements that define the disclosure obligation in cases where a licensee has chosen to meet its obligation through an Internet Web site.

DATES: This rule contains information collection requirements that have not been approved by OMB. The Commission will publish a document in the **Federal Register** announcing the effective date.

FOR FURTHER INFORMATION CONTACT: Raelynn Remy, *Raelynn.Remy@fcc.gov,* or Raphael Sznajder, *Raphael.Sznajder@fcc.gov,* Federal Communications Commission, Media Bureau, (202) 418–2120.

SUPPLEMENTARY INFORMATION: This is a summary of the Commission's *Report and Order* (''*Order*''), MB Docket No. 14–226, FCC 15–118, which was adopted and released on September 17, 2015. The full text of this document is available for public inspection and copying during regular business hours in the FCC Reference Center, Federal Communications Commission, 445 12th Street SW., Room CY–A257, Washington, DC 20554. This document will also be available via ECFS at *http://fjallfoss.fcc.gov/ecfs/.* Documents will be available electronically in ASCII, Microsoft Word, and/or Adobe Acrobat. Alternative formats are available for people with disabilities (Braille, large print, electronic files, audio format), by sending an email to *fcc504@fcc.gov* or calling the Commission's Consumer and Governmental Affairs Bureau at (202) 418–0530 (voice), (202) 418–0432 (TTY).

Paperwork Reduction Act of 1995 Analysis

This document contains new or modified information collection requirements subject to the Paperwork Reduction Act of 1995 (PRA).[1] The requirements 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 or modified information collection requirements contained in this proceeding. In addition, we note that pursuant to the Small Business Paperwork Relief Act of 2002, we previously sought specific comment on how the Commission might further reduce the information collection burden for small business concerns with fewer than 25 employees.

I. Introduction

1. Our ''Contest Rule,'' Section 73.1216 of our rules, requires broadcast licensees to disclose on air the material terms of contests that they broadcast. In this *Order,* we update that rule to permit broadcast licensees to comply with their obligation to disclose material contest terms either by broadcasting those terms or by making them available in writing on a publicly accessible Internet Web site. In particular, we amend the Contest Rule to allow licensees to satisfy their disclosure obligation by posting material contest terms on the station's Web site, the licensee's Web site, or, if neither the individual station nor the licensee has its own Web site, any Internet Web site that is readily accessible to the public. Commenters in this proceeding uniformly support updating the Contest Rule, which has remained unchanged since its adoption by the Commission almost forty years ago.

2. We also adopt, with some modifications, requirements proposed in the Notice of Proposed Rulemaking that define the disclosure obligation in cases where a licensee has chosen to meet its obligation through an Internet Web site. Specifically, we revise the Contest Rule to specify that in such cases a licensee: (i) Must broadcast the relevant Web site address periodically with information sufficient for a consumer easily to find material contest terms online; (ii) must establish a link or tab to material contest terms on the Web site's home page; (iii) must maintain contest terms online for a period of at least thirty days after the contest has ended; and (iv) must announce on air that the material terms of a contest have changed since the contest was first announced, where that is the case, and direct participants to the Web site to review the changes. As discussed below, the announcements of any change in contest terms must be made within 24 hours of the change and periodically thereafter. Finally, we require that licensees ensure that any material terms disclosed on a Web site conform in all substantive respects to those mentioned over the air.

3. The actions we take in this *Order* to update the Contest Rule advance the public interest by affording broadcasters more flexibility in the manner of their compliance with Section 73.1216 while giving consumers improved access to important contest information. Through this *Order,* we take another step to modernize our rules to reflect how Americans access and consume information in the 21st century. At the same time, we affirm the core principles of the Contest Rule. Regardless of the medium of disclosure, broadcasters must provide complete, accurate, and timely information about the contests they conduct, ensure that such information is not false, misleading, or deceptive, and conduct their contests substantially as announced or advertised.

---

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

II. Background

4. Radio and television broadcast stations often conduct contests as a means of entertainment, promoting station support, and deepening audience engagement.[2] Almost forty years ago, in 1976, the Commission adopted the Contest Rule to address concerns about the way in which broadcast stations were conducting contests.[3] Although under the existing rule, a licensee may use non-broadcast methods to disclose material contest terms, it cannot substitute such methods for the required broadcast disclosure and be deemed compliant with the rule.[4]

5. In January 2012, Entercom Communications Corp. (''Entercom'' or ''Petitioner'') filed an unopposed Petition for Rulemaking asking the Commission to update the disclosure requirements of Section 73.1216.[5] Petitioner principally sought an amendment to Section 73.1216 that would allow broadcasters to satisfy their obligation to disclose material contest terms either through broadcast announcements or by making such terms available in written form on an Internet Web site. In November 2014, the Commission issued a Notice of Proposed Rulemaking (''*NPRM''*) seeking comment on a number of possible revisions to the Contest Rule. Commenters responding to the *NPRM,* largely broadcasters, support updating the Contest Rule but advocate some modifications to the Commission's proposed revisions.

[2] *See NPRM,* 79 FR 75773.

[3] *See* 47 CFR 73.1216; *Amendment of Part 73 of the Commission's Rules Relating to Licensee-Conducted Contests,* Report and Order, 60 F.C.C.2d 1072 (1976). *See also Public Notice Concerning Failure of Broadcast Licensees to Conduct Contests Fairly,* 45 F.C.C.2d 1056 (1974) (identifying contest practices that raise questions about a broadcast licensee's responsibility to the public, such as: (1) Disseminating false or misleading information regarding the amount or nature of prizes; (2) failing to control the contest to assure a fair opportunity for contestants to win the announced prizes; (3) urging participation in a contest, or urging persons to stay tuned to the station in order to win, at times when it is not possible to win prizes; (4) failing to award prizes, or failing to award them within a reasonable time; (5) failing to set forth fully and accurately the rules and conditions for contests; (6) changing the rules or conditions of a contest without advising the public or doing so promptly; and (7) using arbitrary or inconsistently applied standards in judging entries).

[4] 47 CFR 73.1216, Note 2 (''The material terms should be disclosed periodically by announcements broadcast on the station conducting the contest. . . . In addition to the required broadcast announcements, disclosure of the material terms may be made in a non-broadcast manner.'').

[5] *See* Petition for Rulemaking filed by Entercom Communications Corp., CGB Docket No. RM–11684 (filed Jan. 20, 2012) (''*Petition for Rulemaking''*).

III. Discussion

A. Satisfying the Obligation To Disclose Material Contest Terms through an Internet Web site

6. As advocated by all of the commenters, we amend the Contest Rule to allow broadcast licensees to meet their obligation to disclose material contest terms either by broadcasting the material terms or by making those terms available in written form on a readily accessible public Internet Web site. We agree with parties who assert that, given the ubiquitous nature of the Internet and current consumer expectations about how to obtain information, broadcast disclosure of material contest terms no longer reflects the best means of conveying such information to the public in all cases. For example, although on-air disclosure may be preferable in certain circumstances, *e.g.,* simple contests and cases in which stations lack Web sites, we believe that broadcasters should be given flexibility to meet their disclosure obligation either through broadcast announcements or the Internet, and we will defer to broadcasters' discretion in selecting between those means of disclosure. As explained below, we find that revising the Contest Rule to permit reliance on online disclosure will provide benefits to both consumers and broadcasters, and that such benefits outweigh any associated costs.

7. Based on the record, we conclude that allowing broadcasters to meet their obligation to disclose material contest terms through the Internet in lieu of broadcasting the terms will benefit consumers by improving their access to important contest information, to the extent that our action results in greater use of online disclosure. Because the current rule requires that licensees disclose material contest terms via broadcast announcements periodically, audience members interested in a contest may not hear or see contest disclosures if they are not tuned into the broadcast at the time the announcement is aired. Moreover, even in cases where prospective contestants hear or see a contest disclosure, the length or complexity of contest terms or the speed at which licensees communicate those terms may render it difficult for many to comprehend or recall the information conveyed. For these reasons, we agree with parties who assert that broadcasters' online posting of material terms will allow consumers to obtain ''on demand'' access to those terms and to review them at their convenience, thereby increasing the likelihood that contest terms will be understood and remembered.

8. We find that this revision to the Contest Rule is consistent with consumer expectations about how to obtain contest information. As many parties note, the public today accesses information in ways that are dramatically different from how they did when the Contest Rule was adopted. The Internet has become a fundamental part of consumers' daily lives and now represents the medium used most by the public to obtain information instantaneously. Given that Americans today are accustomed to using the Internet to obtain a broad range of information, we agree with parties who assert that consumers reasonably expect to obtain information about licensee-conducted contests through the Internet. Indeed, as some parties note, broadcasters already use the Internet to post contest-related information, and consumers often enter and participate in contests via the Internet. Amending the Contest Rule to permit reliance on online disclosure of material contest terms thus brings the rule into alignment with current consumer expectations.

9. As noted, permitting reliance on online disclosure of contest terms also will benefit broadcasters by affording them greater flexibility in the manner of their compliance with Section 73.1216 and by freeing up air time for other programming. Because many broadcasters already have dedicated Web sites where they can post complete contest information that the public can access ''on demand,'' and because we are not requiring broadcasters to use online posting if they prefer to broadcast contest terms over the air, we agree with parties who assert that the benefits of this rule change outweigh any associated costs.

B. Requirements Governing Online Disclosure of Material Contest Terms

10. Although this rule revision is intended, in part, to give broadcasters more flexibility in how they satisfy their obligation to disclose material contest terms, we find that the public interest will be served by establishing specific requirements that define the disclosure obligation in cases where a broadcaster chooses to meet that obligation through an Internet Web site. In particular, we believe that these requirements, which are comparable to those that apply to on-air disclosures,[6] will provide guidance to licensees and facilitate useful access to contest information by the public. We discuss each requirement, in turn, below.

[6] *See* 47 CFR 73.1216, Notes 1 through 3.

11. *''Publicly Accessible'' Web site.* We require that any Internet Web site relied on by a broadcaster to disclose material contest terms be ''publicly accessible.'' We interpret the term ''publicly accessible'' to mean that the Internet Web site is designed to be accessible to the public 24/7, for free, and without any registration requirement.[7] This may include either the station's Web site, the licensee's Web site, or, if neither the individual station nor the licensee has its own Web site, any Internet Web site that is readily accessible to the public. Commenters generally agree that consumers should have access to material contest terms disclosed on a Web site without any fee or registration, and we believe that adopting these requirements will facilitate widespread and unfettered access to contest terms by broadcast audiences. Some parties assert that broadcasters should not be required to make available material contest terms on a 24/7 basis because factors beyond their control, such as system outages, power failures, and hacked Web sites could prevent them from ensuring 24/7 access. Thus, they express concern that they could be exposed to liability for violation of the Contest Rule even where they have made a good faith effort to ensure public accessibility. Because we require that any Web site used to disclose material contest terms be *designed* to be accessible to the public on a 24/7 basis, we believe the rule we adopt accounts for factors beyond the control of the licensee.

12. *Broadcast Identification of Web site Address.* We also amend the Contest Rule to require that a licensee broadcast the address of an Internet Web site on which it relies to disclose material contest terms with information sufficient for a consumer to find those terms easily. Although we proposed in the *NPRM* to require licensees that choose to satisfy their disclosure obligation through the Internet to broadcast the ''complete, direct Web site address'' where contest terms are posted,[8] we decline to adopt this requirement. We agree with commenters that a literal interpretation of such a requirement could be unduly burdensome to broadcasters and confusing to the public. Some parties contend, for example, that a rule requiring identification of the ''complete, direct'' Web site address could be interpreted to require a mechanical recitation of a web address as it appears on an Internet browser (*e.g.,* ''http-colon-backslash, etc.''), and that such a rule is less helpful to consumers than one that allows broadcasters to identify the relevant address through simple instructions or natural language (*e.g.,* ''for contest rules go to kxyz.com and then click on the contest tab''). In addition, Joint Commenters assert that Web site addresses and their subdirectories may change while contests are ongoing, and thus requiring identification of a ''complete, direct'' address, including local host names and subdirectories, would be unnecessarily onerous to broadcasters and could be confusing to consumers. We require that broadcasters identify the Web site in language that enables a typical consumer easily to locate the Web site's home page online, such as in the example provided above (''for contest rules go to kxyz.com and then click on the contest tab''). As with all elements of contest-related announcements, the burden is on the broadcaster to inform the public, not on the public to discern the message.

13. Consistent with broadcasters' existing obligation to broadcast contest rule disclosures ''periodically,'' we conclude further that licensees must broadcast the Web site address where contest terms are posted ''periodically'' during the period of the contest. Although we proposed in the *NPRM* to require licensees to broadcast the Web site address ''each time the station mentions or advertises the contest,''[9] we decline to adopt this requirement, which parties uniformly oppose. For example, some commenters argue that such a requirement could create unnecessary aural clutter and disrupt the listener experience. Parties also assert that, given the number of contests that are conducted simultaneously and the multitude and variety of contest references, requiring licensees to identify the relevant Web site address each time a contest is mentioned will reduce the amount of air time that can be utilized for other programming. Some parties contend further that the burdens imposed by such a requirement could cause stations to reduce the number of contest mentions or not to adopt online disclosure. For these reasons, we are persuaded that the potential drawbacks of requiring broadcast identification of the Web site address where contest terms are posted each time a contest is mentioned outweigh any associated benefits.

14. We decline at this time to adopt a more prescriptive requirement governing the frequency of broadcast identification of the Web site address where contest terms are posted as some parties have suggested.[10] We conclude that requiring on-air identification of the Web site address a specified number of times daily, *e.g.,* an average of three times per day, would not serve the public interest because such a rule could lead broadcasters to identify the Web site address the specified minimum number of times irrespective of how often a contest is mentioned. Similarly, we decline to require broadcast identification of the Web site address only when a station substantially highlights or discusses a contest, as proposed by Hubbard and NSBA, as this approach would make the Contest Rule more challenging to enforce by requiring the Commission to assess in a particular case whether a contest has been ''substantially'' highlighted or discussed.[11] On balance, we find that the public interest would be better served by providing licensees with flexibility to determine the frequency with which they broadcast the Web site address where contest terms are made available to the public. As noted, the requirement we adopt is harmonious with licensees' existing obligation to broadcast contest disclosures ''periodically''[12] and the discretion long afforded licensees in this area.[13] If we find that licensees are failing to broadcast the Web site address with adequate frequency, we will revisit this issue in the future.

15. *Internet Link to Contest Terms.* As proposed in the *NPRM,* we also amend

[7] *See NPRM,* 79 FR 75773, 75775.

[8] *Id.*

[9] *Id.*

[10] *See, e.g.,* iHeartMedia Comments at 13; Joint Parties Comments at 7 (suggesting that the Commission could require licensees to broadcast the Web site address an average of at least three times per day, excluding the hours of 12 to 6 a.m.). *See also* Hubbard Comments at 4; NSBA Comments at 5 (suggesting that the Commission could require licensees to broadcast the Web site address when they substantially highlight or discuss a contest, *i.e.,* not during passing references). We note that some of these suggestions were proffered as an alternative to our proposal in the *NPRM* to require licensees to broadcast the relevant Web site address *each time* a contest is mentioned, and that some of these parties advocate principally for the requirement adopted herein (*i.e.,* periodic broadcast identification of the Web site address). Nevertheless, we set forth above our reasons for declining to adopt those alternatives.

[11] Given the potential number of spontaneous, unscripted contest promotions, *e.g.,* by on-air radio personalities, we also believe that adopting this proposal could result in a high number of Contest Rule violations. *See, e.g.,* Entercom Comments at 9; iHeartMedia Comments at 12; NSBA Comments at 5.

[12] *See* 47 CFR 73.1216, Note 2 (directing, among other things, disclosure of material contest terms be made ''periodically by announcements broadcast on the station conducting the contest, but need not be enumerated each time an announcement promoting the contest is broadcast'').

[13] *Id.* (stating that ''[i]n general, the time and manner of disclosure of the material terms of a contest are within the licensee's discretion,'' and that ''[d]isclosure of material terms in a reasonable number of announcements is sufficient'').

the Contest Rule to require that licensees establish a link or tab on the home page of an Internet Web site used to disclose material contest terms, that takes consumers to contest information.[14] That link or tab must be conspicuously located on the Web site home page and must be labeled in a way that makes clear its relation to contest information. We disagree with commenters' assertions that the Commission need not adopt any rules to facilitate access to contest information because broadcasters have a natural incentive to make such information readily accessible and consumers can utilize Internet search engines to locate contest information quickly. Even if many consumers are able to locate contest terms absent any guidance, we believe that requiring broadcasters to establish a conspicuous link or tab on the Web site home page that takes users to contest terms will facilitate ready access to those terms by the public. As noted, the record reflects that many broadcasters already make available a link or tab to contest information on their Web site home page, which suggests that compliance with such a requirement is not unduly burdensome. Although some parties assert that licensees are in the best position to determine where contest information should be posted on a Web site, the rule we adopt requiring a link or tab to contest terms on a Web site home page does not dictate the location where material terms must be disclosed. To the contrary, the rule preserves the ability of broadcasters to maintain contest terms on a dedicated Web page, so long as that Web page is accessible by a link or tab on the home page that meets the requirements above.

16. *Duration of Online Disclosure Obligation.* We also require licensees that choose to disclose material contest terms via an Internet Web site to maintain such terms on the Web site for at least thirty days after the contest has concluded (*i.e.,* thirty days after a winner has been selected and the station has notified the winner personally or publicly announced the winner by broadcast announcement or over the Internet site where it disclosed the contest rules). We note that under the existing rule, a licensee's obligation to disclose material terms ''arises at the time the audience is first told how to enter or participate and continues thereafter;'' however, the rule is silent on when this obligation ends.[15] In the *NPRM,* we sought comment on how long a licensee should be required to maintain contest information on an Internet Web site.[16] Although no commenter proposed the thirty-day period we adopt herein, we believe this time period is reasonable because it strikes an appropriate balance between the public's interest in accessing material terms after a contest has ended and the interest of broadcasters in keeping their Web sites up-to-date.[17] We disagree with parties who assert that the Commission should refrain from specifying the duration that material contest terms must remain available online, or should require broadcasters to maintain online disclosures only until a contest winner has been selected. We believe that requiring broadcasters to maintain contest terms online for a reasonable period of time after a contest winner has been selected is necessary to ensure that contest information is readily available not only to potential contest participants, but also to actual contestants or others who wish to consult or confirm the rules after the contest has ended.[18] To address concerns that maintaining contest rules online after a contest has ended could create confusion about whether a contest is ongoing, licensees should timely label expired contest terms to make clear that a contest has ended, including the date that a winner was selected.[19]

17. *Changes to Material Contest Terms.* The Contest Rule prohibits false, misleading or deceptive contest descriptions and requires broadcasters to conduct their contests substantially as announced.[20] Accordingly, we do not expect broadcasters to regularly change the material terms of a contest after the contest has commenced. Nevertheless, we recognize that, on rare occasions, limited changes to a contest's terms may be necessary to address changes in circumstances beyond the anticipation or control of the broadcaster. We therefore adopt our proposal to require that, in cases where a licensee chooses to satisfy its disclosure obligation through the Internet, if the material terms of a contest are changed after the contest is first announced, the licensee must announce on air that the contest rules have been changed and direct participants to the Web site to review the changes.[21] With the exception of NPR, commenters support this proposal. As suggested by some parties, we require licensees to make such announcements on air within 24 hours of the change in material terms on the Web site,[22] and periodically thereafter, until the contest has concluded.[23] We are not persuaded by NPR's speculative assertion that requiring broadcasters to announce changes to material contest terms over the air could lead to public confusion about whether contest terms posted on a Web site are accurate.[24] We believe that stations can address this concern by labeling contest terms with information that indicates, for example, the date that the terms were last updated. We believe that requiring on-air announcements of changes in material contest terms is necessary to address the potential that some broadcasters will use their ability to disclose terms online as a means of changing contest rules in a way that is misleading or deceptive to the public. We emphasize that a broadcaster that effectuates a change in terms that unfairly or deceptively alters the

[14] *See NPRM,* 79 FR 75775 (seeking comment on how the Commission can ensure that material contest terms are easy for consumers to locate on an Internet Web site, and on whether to require a link on the Web site's home page to contest terms).

[15] *See* 47 CFR 73.1216, Note 2.

[16] *See NPRM,* 79 FR 75775.

[17] We note that the Commission, in other contexts, has found thirty days to be a reasonable period of notification to the public. *See, e.g., https://www.fcc.gov/asr/localnotice* (visited July 15, 2015) (providing that the Commission will post for thirty days information submitted by applicants for antenna structures that could raise environmental concerns); 47 CFR 76.1601 (requiring that a cable operator provide at least thirty days' notice to subscribers prior to deleting or repositioning a broadcast signal).

[18] Absent such a requirement, for example, a contest winner might not be able to readily confirm that the prize he/she has been awarded after the content has ended is, in fact, the prize disclosed online. Similarly, a losing contestant that wished to consult the contest rules could not readily do so if licensees were permitted to remove the rules immediately upon the contest's conclusion.

[19] *See* 47 CFR 73.1216, Note 1(b) (''Material terms include . . . [the] *time* and means *of selection of winners''*) (emphasis added).

[20] *See* 47 CFR 73.1216.

[21] *See NPRM,* 79 FR 75775 (also seeking comment on the appropriate frequency and duration of this requirement).

[22] *See* Entercom Comments at 11; iHeartMedia Comments at 14 (advocating a requirement that licensees announce changes to material contest terms within 24 hours of the change). We expect licensees to broadcast forthwith announcements of the changes in material terms that they have posted on a Web site, and to not wait 24 hours before doing so.

[23] Although a few parties have suggested that licensees be required to announce on air that contest terms have changed three times daily, *see* Entercom Comments at 11; iHeartMedia Comments at 14; Joint Parties Comments at 9, we conclude that requiring such announcements on a periodic basis will give broadcasters more flexibility in how they satisfy their disclosure obligation, and is consistent with licensees' existing obligation to broadcast contest disclosures ''periodically'' and the discretion granted licensees under the Contest Rule. We note that this requirement also is harmonious with the rule we adopt above governing broadcast identification of Web site addresses.

[24] *See* NPR Comments at 5 (rather than requiring licensees to disclose on air that material contest terms have been changed, the Commission should require them to state clearly on the Web site that contest terms have changed).

operation of the contest or the nature or value of the prize or materially disadvantages existing contestants will be deemed to have rendered prior descriptions false, misleading, and deceptive and, thus, would violate the Contest Rule, regardless of whether such alterations are announced on air or posted to a Web site.[25]

18. *Consistency of Contest Terms.* We adopt our proposal in the *NPRM* to require that any material contest terms disclosed on an Internet Web site conform in all substantive respects to contest terms broadcast over the air.[26] Although no commenter specifically addressed this proposal, we conclude that amending the Contest Rule to include such a requirement serves the public interest by ensuring that contest information made available by broadcasters in written and oral form is consistent. We note that the Contest Rule currently requires licensees, among other things, to disclose material contest terms ''fully and accurately'' and to conduct contests ''substantially as announced or advertised.'' [27] The Contest Rule directs further that ''[n]o contest description shall be false, misleading or deceptive with respect to any material term.'' [28] We believe that prohibiting broadcasters from disclosing material contest terms on an Internet Web site that differ in any substantive respect from contest information broadcast over the air is harmonious with broadcasters' existing obligations under the Contest Rule. In particular, we find that a licensee's failure to disseminate consistent information about a contest it conducts constitutes a violation of the requirements noted above to disclose material contest terms accurately, to conduct contests substantially as announced or advertised, and to provide contest descriptions that are not false, misleading, or deceptive. To the extent that there are any ambiguities in contest disclosures that generate inconsistency, we place broadcasters on notice that the Commission will construe such ambiguities against the licensee. We believe that this approach will benefit broadcast audiences by facilitating clarity and consistency in contest disclosures.

[25] *See* 47 CFR 73.1216.

[26] *See NPRM,* 79 FR 75775. As noted in the *NPRM,* for example, if a broadcast contest announcement identifies a particular prize by brand name or model, then the terms disclosed on the Web site must be the same. *Id.* para. 12, n.41.

[27] *See* 47 CFR 73.1216.

[28] *Id.*

IV. Procedural Matters

A. Regulatory Flexibility Act

19. As required by the Regulatory Flexibility Act of 1980, as amended (''RFA'') [29] an Initial Regulatory Flexibility Act Analysis (''IRFA'') was incorporated in the *Notice of Proposed Rulemaking* (''*NPRM''*) in this proceeding. The Commission sought written public comment on the proposals in the *NPRM,* including comment on the IRFA. The Commission received no comments on the IRFA. This Final Regulatory Flexibility Act Analysis (''FRFA'') conforms to the RFA.[30]

1. Need for, and Objectives of, the Rule Changes

20. This proceeding stems from an unopposed Petition for Rulemaking filed by Entercom Communications Corp. requesting that the Commission update Section 73.1216 of its rules governing broadcast licensee-conducted contests (the ''Contest Rule'') [31] in a manner that reflects how consumers access information in the 21st Century.[32] In November 2014, the Commission issued a *NPRM* seeking comment on certain proposals intended to modernize the Contest Rule by providing broadcasters with more flexibility in how they satisfy their obligation to disclose material contest terms, without relaxing their duty to conduct contests with due regard for the public interest.

21. In the accompanying *Order,* the Commission amends the Contest Rule to permit broadcast licensees to comply with their obligation to disclose material contest terms either by broadcasting such terms or by making them available in writing on a publicly accessible Internet Web site. In particular, the *Order* amends the rule to allow a broadcast licensee to satisfy its disclosure obligation by posting material contest terms on the station's Web site, the licensee's Web site, or, if neither the individual station nor the licensee has its own Web site, any Internet Web site that is readily accessible to the public.

22. The *Order* also revises the Contest Rule to specify that, in cases where a licensee chooses to disclose material contest terms through an Internet Web site, the licensee: (i) Must broadcast the relevant Web site address periodically with information sufficient for a consumer to easily find material contest terms online; (ii) must establish a link or tab to material contest terms on the Web site's home page; (iii) must maintain contest terms online for a period of at least thirty days after the contest has ended; and (iv) that changes the material terms of a contest after the contest is first announced must announce on air that the contest rules have changed and direct participants to the Web site to review the changes. The *Order* requires that such announcements be made on air within 24 hours of the change in contest terms on the Web site, and periodically thereafter. Finally, licensees must ensure that any material terms disclosed on a Web site conform in all substantive respects to those mentioned over the air.

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

[30] *See* 5 U.S.C. 604.

[31] 47 CFR 73.1216.

[32] *See* Petition for Rulemaking filed by Entercom Communications Corp., CGB Docket No. RM–11684 (filed Jan. 20, 2012).

2. Summary of Significant Issues Raised by Public Comments in Response to the IRFA

23. No comments were filed that specifically addressed the IRFA.

3. Description and Estimates of the Number of Small Entities to Which the Proposed Rules Will Apply

24. The RFA directs agencies to provide a description of and, where feasible, an estimate of the number of small entities that may be affected by the proposed rules, if adopted.[33] The RFA generally defines the term ''small entity'' as having the same meaning as the terms ''small business,'' ''small organization,'' and ''small governmental jurisdiction.'' [34] In addition, the term ''small business'' has the same meaning as the term ''small business concern'' under the Small Business Act.[35] 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.[36] The rules

[33] 5 U.S.C. 603(b)(3).

[34] 5 U.S.C. 601(6).

[35] 5 U.S.C. 601(3) (incorporating by reference the definition of ''small business concern'' in 15 U.S.C. 632). Pursuant to 5 U.S.C. 601(3), the statutory definition of a small business applies ''unless an agency, after consultation with the Office of Advocacy of the Small Business Administration and after opportunity for public comment, establishes one or more definitions of such term which are appropriate to the activities of the agency and publishes such definition(s) in the **Federal Register.''** 5 U.S.C. 601(3).

[36] 15 U.S.C. 632. Application of the statutory criteria of dominance in its field of operation and independence are sometimes difficult to apply in the context of broadcast television. Accordingly, the Commission's statistical account of television stations may be over-inclusive.

adopted in the accompanying *Order* will directly affect small television and radio broadcast stations. Below, we provide a description of these small entities, as well as an estimate of the number of such small entities, where feasible.

25. *Television Broadcasting.* This economic Census category ''comprises establishments primarily engaged in broadcasting images together with sound.'' [37] The SBA has created the following small business size standard for such businesses: Those having $38.5 million or less in annual receipts.[38] The 2007 U.S. Census indicates that 808 firms in this category operated in that year. Of that number, 709 had annual receipts of $25,000,000 or less, and 99 had annual receipts of more than $25,000,000.[39] Because the Census has no additional classifications that could serve as a basis for determining the number of stations whose receipts exceeded $38.5 million in that year, we conclude that the majority of television broadcast stations were small under the applicable SBA size standard.

26. Apart from the U.S. Census, the Commission has estimated the number of licensed commercial television stations to be 1,387 stations.[40] Of this total, 1,221 stations (or about 88 percent) had revenues of $38.5 million or less, according to Commission staff review of the BIA Kelsey Inc. Media Access Pro Television Database (BIA) on July 2, 2014. In addition, the Commission has estimated the number of licensed noncommercial educational (NCE) television stations to be 395.[41] NCE stations are non-profit, and therefore considered to be small entities.[42] Based on these data, we estimate that the majority of television broadcast stations are small entities.

27. *Class A TV and LPTV Stations.* The same SBA definition that applies to television broadcast stations would apply to licensees of Class A television stations and low power television (LPTV) stations, as well as to potential licensees in these television services. As noted above, the SBA has created the following small business size standard for this category: Those having $38.5 million or less in annual receipts.[43] The Commission has estimated the number of licensed Class A television stations to be 432.[44] The Commission has also estimated the number of licensed LPTV stations to be 2,028.[45] Given the nature of these services, we will presume that these licensees qualify as small entities under the SBA definition.

28. We note, however, that in assessing whether a business concern qualifies as ''small'' under the above definition, business (control) affiliations [46] must be included. Because we do not include or aggregate revenues from affiliated companies in determining whether an entity meets the revenue threshold noted above, our estimate of the number of small entities affected is likely overstated. In addition, we note that one element of the definition of ''small business'' is that an entity not be dominant in its field of operation. We are unable at this time to define or quantify the criteria that would establish whether a specific television broadcast station is dominant in its field of operation. Accordingly, our estimate of small television stations potentially affected by the proposed rules includes those that could be dominant in their field of operation. For this reason, such estimate likely is over-inclusive.

29. *Radio Stations.* This economic Census category ''comprises establishments primarily engaged in broadcasting aural programs by radio to the public.'' [47] The SBA has created the following small business size standard for this category: Those having $38.5 million or less in annual receipts.[48] Census data for 2007 shows that 2,926 firms in this category operated in that year.[49] Of this number, 2,877 firms had annual receipts of less than $25,000,000, and 49 firms had annual receipts of $25,000,000 or more.[50] Because the Census has no additional classifications that could serve as a basis for determining the number of stations whose receipts exceeded $38.5 million in that year, we conclude that the majority of television broadcast stations were small under the applicable SBA size standard.

30. Apart from the U.S. Census, the Commission has estimated the number of licensed commercial AM radio stations to be 4,553 stations and the number of commercial FM radio stations to be 6,622, for a total number of 11,175.[51] Of this total, 9,898 stations (or about 90 percent) had revenues of $38.5 million or less, according to Commission staff review of the BIA Kelsey Inc. Media Access Pro Television Database (BIA) on October 23, 2014. In addition, the Commission has estimated the number of licensed noncommercial educational (''NCE'') AM radio stations to be 168 stations and the number of noncommercial educational FM radio stations to be 4,082, for a total of 4,250.[52] NCE stations are non-profit, and therefore considered to be small entities.[53] Therefore, we estimate that the majority of radio broadcast stations are small entities.

31. *Low Power FM Stations.* The same SBA definition that applies to radio stations would apply to low power FM stations. As noted above, the SBA has created the following small business size standard for this category: Those having $38.5 million or less in annual receipts.[54] The Commission has estimated the number of licensed low power FM stations to be 814.[55] Given the nature of these services, we will presume that these licensees qualify as small entities under the SBA definition.

32. We note again, however, that in assessing whether a business concern qualifies as ''small'' under the above definition, business (control) affiliations [56] must be included. Because

---

[37] U.S. Census Bureau, 2012 NAICS Definitions, ''515120 Television Broadcasting,'' at *http://www.census.gov/cgi-bin/sssd/naics/naicsrch.*

[38] 13 CFR 121.201; 2012 NAICS code 515120.

[39] U.S. Census Bureau, Table No. EC0751SSSZ4, *Information: Subject Series—Establishment and Firm Size: Receipts Size of Firms for the United States: 2007* (515120), *http://factfinder2.census.gov/faces/tableservices/jsf/pages/productview.xhtml?pid=ECN_2007_US_51SSSZ4&prodType=table.*

[40] *See Broadcast Station Totals as of June 30, 2014,* Press Release (MB rel. July 9, 2014) (*Broadcast Station Totals*) at *https://apps.fcc.gov/edocs_public/attachmatch/DOC-328096A1.pdf.*

[41] *See Broadcast Station Totals, supra.*

[42] *See generally* 5 U.S.C. 601(4), (6).

[43] 13 CFR 121.201; NAICS code 515120.

[44] *See Broadcast Station Totals, supra.*

[45] *See Broadcast Station Totals, supra.*

[46] ''[Business concerns] are affiliates of each other when one concern controls or has the power to control the other or a third party or parties controls or has the power to control both.'' 13 CFR 21.103(a)(1).

[47] U.S. Census Bureau, 2012 NAICS Definitions, ''515112 Radio Stations,'' at *http://www.census.gov/cgi-bin/sssd/naics/naicsrch.* This category description continues, ''Programming may originate in their own studio, from an affiliated network, or from external sources.''

[48] 13 CFR 121.201; NAICS code 515112.

[49] U.S. Census Bureau, Table No. EC0751SSSZ4, *Information: Subject Series—Establishment and Firm Size: Receipts Size of Firms for the United States: 2007* (515112), *http://factfinder2.census.gov/faces/tableservices/jsf/pages/productview.xhtml?pid=ECN_2007_US_51SSSZ4&prodType=table.*

[50] *Id.*

[51] *See Broadcast Station Totals as of June 30, 2014,* Press Release (MB rel. July 9, 2014) (*Broadcast Station Totals)* at *https://apps.fcc.gov/edocs_public/attachmatch/DOC-328096A1.pdf.* This document only indicates the total number of AM stations as 4,721. The breakdown between licensed AM commercial and noncommercial stations was obtained from Staff review of the Consolidated Database System (CDBS). *See http://licensing.fcc.gov/prod/cdbs/pubacc/prod/cdbs_pa.htm.*

[52] *See Broadcast Station Totals, supra.*

[53] *See generally* 5 U.S.C. 601(4), (6).

[54] *See* 13 CFR 121.201, NAICS Code 515112.

[55] *See News Release,* ''Broadcast Station Totals as of June 30, 2012'' (rel. Jul. 19, 2012) (*http://fjallfoss.fcc.gov/edocs_public/attachmatch/DOC-304594A1315231A1.pdf*).

[56] ''[Business concerns] are affiliates of each other when one concern controls or has the power to

Continued

we do not include or aggregate revenues from affiliated companies in determining whether an entity meets the applicable revenue threshold, our estimate of the number of small radio broadcast stations affected is likely overstated. In addition, as noted above, one element of the definition of ''small business'' is that an entity not be dominant in its field of operation. We are unable at this time to define or quantify the criteria that would establish whether a specific radio broadcast station is dominant in its field of operation. Accordingly, our estimate of small radio stations potentially affected by the proposed rules includes those that could be dominant in their field of operation. For this reason, such estimate likely is over-inclusive.

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

33. In this section, we identify the reporting, recordkeeping, and other compliance requirements for small entities that the Commission adopts in the *Order.*

34. *Reporting Requirements.* The *Order* does not adopt reporting requirements.

35. *Recordkeeping Requirements.* The *Order* adopts certain recordkeeping requirements that apply to broadcast entities, including small broadcast entities, that choose to disclose material contest terms by posting such terms on an Internet Web site. In particular, the *Order* requires such entities:

- to broadcast the relevant Web site address periodically with information sufficient for a consumer to easily find material contest terms online;
- to establish a link or tab to material contest terms on the Web site's home page;
- to maintain contest terms online for a period of at least thirty days after the contest has ended;
- in cases where such entities change the material terms of a contest after the contest is first announced, to announce on air that the contest rules have changed and direct participants to the Web site to review the changes, and to make such announcements on air within 24 hours of the change on the Web site and periodically thereafter; and
- to ensure that any material terms disclosed on a Web site conform in all substantive respects to those mentioned over the air.

control the other or a third party or parties controls or has the power to control both.'' 13 CFR 21.103(a)(1).

36. *Other Compliance Requirements.* The *Order* does not adopt other compliance requirements.

37. Based on the record, we cannot estimate with precision the impact of the rules adopted in the *Order* on small entities. However, the rule revisions will afford all licensees, including small broadcasters, greater flexibility in their manner of compliance with the Contest Rule. In addition, we note that some of the rule revisions were derived from the Petition for Rulemaking in this proceeding, which was unopposed and supported by all commenters, including small broadcasters. Thus, we find it reasonable to conclude that any costs or burdens on small entities resulting from the requirements will be outweighed by the benefits.

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

38. The RFA requires an agency to describe any significant, specifically small business, 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 and reporting requirements under the rule for such 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.[57]

39. The accompanying *Order* amends Section 73.1216 of the Commission's rules by allowing all licensees, including small broadcasters, to meet their obligation to disclose material contest terms either through broadcast announcements or by making such terms available in writing on a publicly accessible Internet Web site. This revision to the rule is intended to give broadcasters greater flexibility in the manner by which they satisfy their obligation to disclose material contest terms, while ensuring adequate notice of such terms to the public. Whereas under the current rule, licensees must expend time and resources developing broadcast messages that adequately disclose important contest information, under the revised rule, licensees will have the option to disclose such information through the Internet. Permitting disclosure through this additional method likely is less costly and administratively burdensome for licensees, including small entities. One commenter has estimated, for example, that as much as two hours that are presently devoted by licensees to the production of contest-related broadcast spots will be spared. Moreover, the air time that is likely to be freed up as a result of more abbreviated contest-related announcements could be used for non-contest-related programming. As noted above, the Petition for Rulemaking in this proceeding was uniformly supported by commenting parties, including small entities. Thus, we expect that the rule revisions adopted in the *Order* will benefit small broadcast entities.

[57] 5 U.S.C. 603(c)(1)–(c)(4).

B. Report to Congress

40. The Commission will send a copy of this *Order* to Congress and the Government Accountability Office pursuant to the Congressional Review Act, see 5 U.S.C. 801(a)(1)(A).

C. Paperwork Reduction Act

41. This document contains new or modified information collection requirements subject to the Paperwork Reduction Act of 1995 (PRA). The requirements 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 or modified information collection requirements contained in this proceeding. In addition, we note that pursuant to the Small Business Paperwork Relief Act of 2002, we previously sought specific comment on how the Commission might further reduce the information collection burden for small business concerns with fewer than 25 employees.

V. Ordering Clauses

42. Accordingly, IT IS ORDERED that, pursuant to the authority contained in Sections 4(i), 4(j) and 303 of the Communications Act of 1934, as amended, 47 U.S.C. 154(i), 154(j), and 303, this *Report and Order* IS ADOPTED, and shall become effective upon announcement in the **Federal Register** of OMB approval and an effective date of the rules adopted therein.

43. IT IS FURTHER ORDERED that, pursuant to the authority found in Sections 4(i), 4(j) and 303 of the Communications Act of 1934, as amended, 47 U.S.C. 154(i), 154(j), and 303, the Commission's rules ARE HEREBY AMENDED as set forth in Appendix B.

44. IT IS FURTHER ORDERED that the Commission's Consumer and

Governmental Affairs Bureau, Reference Information Center, SHALL SEND a copy of this *Report and Order,* including the Final Regulatory Flexibility Act Analysis, to the Chief Counsel for Advocacy of the Small Business Administration.

45. IT IS FURTHER ORDERED that the Commission SHALL SEND a copy of this *Report and Order* 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 in 47 CFR Part 73

Advertising, Consumer protection, Fraud, Television broadcasters.

Federal Communications Commission.

Marlene H. Dortch,

Secretary.

Final Rules

For the reasons discussed in the preamble, the Federal Communications Commission amends 47 CFR part 73 as follows:

PART 73—RADIO BROADCAST SERVICE

■ 1. The authority citation for part 73 continues to read as follows:

Authority: 47 U.S.C. 154, 303, 334, 336, and 339.

■ 2. Revise § 73.1216 to read as follows:

§ 73.1216 Licensee-conducted contests.

(a) A licensee that broadcasts or advertises information about a contest it conducts shall fully and accurately disclose the material terms of the contest, and shall conduct the contest substantially as announced or advertised over the air or on the Internet. No contest description shall be false, misleading or deceptive with respect to any material term.

(b) The disclosure of material terms shall be made by the station conducting the contest by either:

(1) Periodic disclosures broadcast on the station; or

(2) Written disclosures on the station's Internet Web site, the licensee's Web site, or if neither the individual station nor the licensee has its own Web site, any Internet Web site that is publicly accessible.

(c) In the case of disclosure under paragraph (b)(1) of this section, a reasonable number of periodic broadcast disclosures is sufficient. In the case of disclosure under paragraph (b)(2) of this section, the station shall:

(1) Establish a conspicuous link or tab to material contest terms on the home page of the Internet Web site;

(2) Announce over the air periodically the availability of material contest terms on the Web site and identify the Web site address where the terms are posted with information sufficient for a consumer to find such terms easily; and

(3) Maintain material contest terms on the Web site for at least thirty days after the contest has concluded. Any changes to the material terms during the course of the contest must be fully disclosed on air within 24 hours of the change on the Web site and periodically thereafter or the fact that such changes have been made must be announced on air within 24 hours of the change, and periodically thereafter, and such announcements must direct participants to the written disclosures on the Web site. Material contest terms that are disclosed on an Internet Web site must be consistent in all substantive respects with those mentioned over the air.

Note 1 to § 73.1216: For the purposes of this section:

(a) A contest is a scheme in which a prize is offered or awarded, based upon chance, diligence, knowledge or skill, to members of the public.

(b) Material terms include those factors which define the operation of the contest and which affect participation therein. Although the material terms may vary widely depending upon the exact nature of the contest, they will generally include: How to enter or participate; eligibility restrictions; entry deadline dates; whether prizes can be won; when prizes can be won; the extent, nature and value of prizes; basis for valuation of prizes; time and means of selection of winners; and/or tie-breaking procedures.

Note 2 to § 73.1216: In general, the time and manner of disclosure of the material terms of a contest are within the licensee's discretion. However, the obligation to disclose the material terms arises at the time the audience is first told how to enter or participate and continues thereafter.

Note 3 to § 73.1216: This section is not applicable to licensee-conducted contests not broadcast or advertised to the general public or to a substantial segment thereof, to contests in which the general public is not requested or permitted to participate, to the commercial advertisement of non-licensee-conducted contests, or to a contest conducted by a non-broadcast division of the licensee or by a non-broadcast company related to the licensee.

[FR Doc. 2015–26093 Filed 10–22–15; 8:45 am]

BILLING CODE 6712–01–P

DEPARTMENT OF ENERGY

48 CFR Parts 925, 952 and 970

RIN 1991–AB99

Acquisition Regulations: Export Control

AGENCY: Department of Energy.

ACTION: Final rule.

SUMMARY: The Department of Energy (DOE) is adopting as final, with changes, a rule amending the Department of Energy Acquisition Regulation (DEAR) to add clauses regarding applicable export control requirements for DOE contracts. The rule recognizes contractor responsibilities to comply with all applicable export control laws and regulations in the performance of DOE contracts and prescribes Export Clauses to address these responsibilities.

DATES: *Effective Date:* November 23, 2015.

Applicability Date: This final rule is applicable to solicitations issued on or after November 23, 2015.

FOR FURTHER INFORMATION CONTACT: Lawrence Butler, (202) 287–1945 or *lawrence.butler@hq.doe.gov.*

SUPPLEMENTARY INFORMATION:

I. Executive Summary

A. Purpose and Legal Authority

The purpose of this rulemaking is to add new DEAR Subparts 925.71 and 970.2571 to clarify requirements concerning compliance with export control laws and regulations applicable in the performance of DOE contracts.

Export control laws and regulations that may apply to a DOE contract include, but are not limited to: The Atomic Energy Act of 1954 (42 U.S.C. 2011 *et seq.*), as amended; the Arms Export Control Act (22 U.S.C. 2751 *et seq.*); the Export Administration Act of 1979 (50 U.S.C. app. 2401 *et seq.*), as continued under the International Emergency Economic Powers Act (Title II of Pub. L. 95–223, 91 Stat. 1626, October 28, 1977); Trading with the Enemy Act (50 U.S.C. App. 1 *et seq.* as amended by the Foreign Assistance Act of 1961); Assistance to Foreign Atomic Energy Activities (10 Code of Federal Regulations (CFR) Part 810); Export Administration Regulations (15 CFR parts 730 through 774); International Traffic in Arms Regulations (22 CFR parts 120 through 130); Export and Import of Nuclear Equipment and Material (10 CFR part 110); and regulations administered by the Office of Foreign Assets Control of the Department of the Treasury (31 CFR parts 500 through 598).

DOE provided summaries of these export control laws in section II of its proposed rule. See 78 FR 35195 (June 12, 2013).

B. Summary of Major Provisions

DOE is amending the DEAR to add provisions similar to the 2013 amendments to the Defense Federal Acquisition Regulation Supplement (DFARS) (DFARS 225, Foreign Acquisition, and DFARS 252, 78 FR 36108, June 17, 2013); DFARS 252, Foreign Acquisition, 78 FR 48331, August 8, 2013; and to the DFARS Procedures, Guidance, and Information (PGI) 225 ''Foreign Acquisition'' (revised June 26, 2013).

1. Part 925—Foreign Acquisition

Part 925 is amended by adding new section 925.71 to set forth requirements for contractors concerning compliance with U.S. export control laws and regulations.

Points of contact and specific U.S. government agency requirements for export controls can be found as follows:

Department of Commerce (DOC): *http://www.bis.doc.gov/licensing/exportingbasics.htm*

Department of Energy, National Nuclear Security Administration, Office of Nonproliferation and International Security: *http://nnsa.energy.gov/aboutus/ourprograms/nonproliferation/programoffices/officenonproliferation internationalsecurity.*

Nuclear Regulatory Commission: *http://www.nrc.gov/about-nrc/ip/export-import.html.*

Department of State: *http://www.pmddtc.state.gov/about/key_personnel.html* and *http://www.pmddtc.state.gov/documents/ddtc_getting_started.pdf.*

Department of Treasury: *http://www.treasury.gov/services/Pages/Foreign-Transaction-Licensing-and-Reporting.aspx.*

DOE contractors are responsible for complying with export control requirements applicable to their contracts as set forth in new DEAR Export Clauses. It is a contractor's responsibility to comply with all applicable export control laws and regulations. This responsibility exists independent of, and is not established or limited by, this DEAR rulemaking.

2. Part 952—Solicitation Provisions and Contract Clauses

Part 952 is amended by adding new clause 952.225–71 to set forth requirements for DOE contractors concerning compliance with applicable export control laws and regulations.

Points of contact and specific U.S. government agency requirements for export controls can be found as follows:

Department of Commerce (DOC): *http://www.bis.doc.gov/licensing/exportingbasics.htm*

Department of Energy, National Nuclear Security Administration, Office of Nonproliferation and International Security: *http://nnsa.energy.gov/aboutus/ourprograms/nonproliferation/programoffices/officenonproliferation internationalsecurity.*

Nuclear Regulatory Commission: *http://www.nrc.gov/about-nrc/ip/export-import.html.*

Department of State: *http://www.pmddtc.state.gov/about/key_personnel.html* and *http://www.pmddtc.state.gov/documents/ddtc_getting_started.pdf.*

Department of Treasury: *http://www.treasury.gov/services/Pages/Foreign-Transaction-Licensing-and-Reporting.aspx.*

DOE contractors are responsible for complying with export control requirements applicable to their contracts as set forth in new DEAR Export Clauses. It is a contractor's responsibility to comply with all applicable export control laws and regulations. This responsibility exists independent of, and is not established or limited by, this DEAR rulemaking.

3. Part 970—DOE Management and Operating Contracts

Subpart 970.25 is amended by adding new section 970.2571 to set forth requirements for management and operating contractors concerning compliance with applicable export control laws and regulations. Subpart 970.52 is amended by adding new clause 970.5225–1 to set forth requirements for management and operating contractors concerning compliance with applicable export control laws and regulations.

Points of contact and specific U.S. government agency requirements for U.S. export controls can be found as follows:

Department of Commerce (DOC): *http://www.bis.doc.gov/licensing/exportingbasics.htm.*

Department of Energy, National Nuclear Security Administration, Office of Nonproliferation and International Security: *http://nnsa.energy.gov/aboutus/ourprograms/nonproliferation/programoffices/officenonproliferation internationalsecurity.*

Nuclear Regulatory Commission: *http://www.nrc.gov/about-nrc/ip/export-import.html.*

Department of State: *http://www.pmddtc.state.gov/about/key_personnel.html* and *http://www.pmddtc.state.gov/documents/ddtc_getting_started.pdf.*

Department of Treasury: *http://www.treasury.gov/services/Pages/Foreign-Transaction-Licensing-and-Reporting.aspx.*

DOE management and operating contractors are responsible for complying with export control requirements applicable to their contracts as set forth in new DEAR Export Clauses. It is the contractor's responsibility to comply with all applicable export control laws and regulations. This responsibility exists independent of, and is not established or limited by, this DEAR rulemaking.

II. Summary of Comments and Responses

DOE published a notice of proposed rulemaking (NOPR) on June 12, 2013 (78 FR 35195). The NOPR reflected the approach previously taken by the Department of Defense (DoD) in the Defense Acquisition Regulations Supplement (DFARS) to address requirements for complying with export control laws and regulations when performing DoD contracts. DOE has received recommendations from the General Accounting Office and the DOE Inspector General to modify the DEAR for the same purpose. DOE received comments from 15 organizations in response to the NOPR. In addition, within days of publication of the NOPR, the DoD revised the DFARS to address issues similar to those reflected in comments received on the NOPR and provided guidance relating to the release of fundamental research information. This final rule reflects the approach taken by the DoD on June 17, 2013, to changes to sections 225.79 and 252.225–7048 of the DFARS (Foreign Acquisition, 78 FR 36108), and to changes to Part 225 of the DFARS PGI—225.79 (Foreign Acquisition, Export Control). This NOPR also reflects DoD guidance in 78 FR 48331, August 8, 2013, related to the release of research information that may be export controlled.

The following paragraphs describe the changes included in this final rule as a result of those comments and provide DOE's response to the comments received.

Summary of Changes to the NOPR

(a) All notification and reporting requirements have been removed.

(b) The requirement for contractors to comply with DOE directives ''in effect on the date of the contract award'' has been removed.

(c) References to ''transfers'' have been removed.

(d) References to specific DOE Orders have been removed.

(e) The Export Restriction Notice has been removed from the Export Clauses.

(f) The phrase ''subject to export controls'' has been removed from the Export Clauses.

(g) All listings of U.S. export control laws and regulations are preceded by, ''include, but are not limited to:''

(h) All references to ''export-controlled items'' and ''export control of items'' have been removed. The rule addresses ''compliance with export control laws and regulations'' and does not attempt to define what is and is not export controlled.

Discussion of comments and responses.

1. Comment: Six respondents claimed that export control laws exist and already apply to U.S. persons, regardless of whether a contractor represents to DOE that it is complying with applicable export laws.

Response: As stated in the NOPR, export compliance responsibilities exist independent of and are not established or limited by the proposed rule. It is customary practice for laws and regulations applicable to DOE contracts to be listed in the contracts. In addition, DOE is requiring the new Export Clauses to be added to all applicable contracts. Listing applicable export laws and regulations in the Export Clauses will help ensure that contractors are aware of their responsibilities, emphasize the importance to DOE of contractor compliance with such laws and regulations, and minimize the risk of non-compliance with U.S. laws and regulations that could have major programmatic and financial impacts on DOE and contractors. No change was made to the text as a result of this comment.

2. Comment: Six respondents claimed that the rule encroaches on the export authority of other U.S. export licensing authorities.

Response: The rule does not affect the export authority of any U.S. Government agency. The purpose of the rule is to direct DOE contractors to seek guidance from and to communicate with export licensing officers at export licensing agencies and not to ask DOE Contracting Officers for assistance in complying with export control requirements. The rule provides explicit instructions to DOE Contracting Officers, if asked by a DOE contractor to provide export assistance, to direct contractors to applicable export laws and regulations and to the agencies administering them. The final rule makes it clear that DOE does not have an export compliance officer overseeing DOE contractor export activities, and that contractors are responsible for compliance with export controls. No change was made to the text as a result of this comment.

3. Comment: Four respondents claimed the proposed rule has existing or potential inconsistencies with export control authorities.

Response: As noted above, the purpose of the rule is to direct DOE contractors to seek guidance from and to communicate with export licensing officers at export licensing agencies and not to ask for export control compliance assistance from DOE Contracting Officers. The final rule has been revised to remove reporting and marking requirements, as well as language cited by one respondent as potentially inconsistent with other authorities.

4. Comment: One respondent expressed concern as to how differences of opinion on the applicability of export control requirements between agencies responsible for administering the laws and the DOE Contracting Officer would be resolved.

Response: The rule makes clear that DOE Contracting Officers do not make any decisions regarding the applicability of export control laws or regulations. The appropriate licensing agency determines whether export control requirements apply. It is a contractor's responsibility to adhere to all relevant export control laws and regulations. No change was made to the text as a result of this comment.

5. Comment: One respondent claimed that DOE is potentially setting up a conflict for a contractor between complying with changes in export laws and regulations that are not yet changed in its contract clause.

Response: The listing of export control laws and regulations in the Export Clauses in the final rule are preceded by ''include, but are not limited to:''. Any changes in U.S. export laws or regulations would apply to a contractor because the Export Clauses require compliance with all applicable export control laws and regulations. No change was made to the text as a result of this comment.

6. Comment: Two respondents alleged that the proposed rule is inconsistent with the Export Control Reform Initiative.

Response: The final rule is consistent with the Export Control Reform Initiative (ECRI). The purpose of this rule is to simplify the export process for DOE contractors, by directing them to the proper export licensing authorities. Reporting requirements have been removed from the final rule.

7. Comment: Three respondents claimed that the proposed rule is redundant to DEAR 970.5204–2 Laws, Regulations and DOE Directives, because that clause adequately covers compliance with export laws and regulations.

Response: The rule clarifies DOE contractor and Contracting Officer responsibilities regarding export controls not clearly stated in any other law or regulation. The Export Clauses clarify that DOE contractors are to contact appropriate export licensing agencies and not DOE Contracting Officers with questions regarding export control compliance. The Export Clauses direct DOE Contracting Officers to address contractor export control questions by directing them to relevant export control laws and regulations and licensing agencies. No change was made to the text as a result of this comment.

8. Comment: One respondent questioned the requirement for contractors to comply with DOE directives ''in effect on the date of the contract award,'' as individual DOE contracts specify applicable DOE directives for each DOE contract.

Response: DOE acknowledges that contracts specify applicable DOE directives. This language has been removed from the final rule.

9. Comment: Two respondents claimed that DOE already has adequate contractual enforcement tools.

Response: The purpose of the rule is not to provide additional enforcement tools. This rule is needed to clarify DOE contractor and Contracting Officer export control responsibilities not clearly stated in any other law or regulation. No change was made to the text as a result of this comment.

10. Comment: Six respondents claimed that export control requirements are not needed in the DEAR and that the Federal Acquisition Regulation (FAR) limits agency acquisition regulations to those necessary to implement FAR policies and procedures.

Response: The final rule provides necessary policies and procedures not included in the FAR. It clarifies that DOE contractors are to consult appropriate export licensing agencies and not DOE Contracting Officers with questions regarding export compliance. The final rule directs DOE Contracting Officers to handle export control questions posed by contractors by directing the contractors to the relevant export licensing agencies. This rule is needed to clarify DOE contractor and DOE Contracting Officer responsibilities that are not clearly stated in any other law or regulation. No change was made to the text as a result of this comment.

11. Comment: Six respondents claimed that the proposed rule exceeds the stated purpose of the rule, which is to amend the DEAR for consistency with a 2010 amendment to the DFARS. They said that the proposed rule is not consistent with the revised DFARS clauses.

Response: The final rule reflects the approach taken in the June 17, 2013, changes to 225.79 and 252.225–7048 of the DFARS (Foreign Acquisition, 78 FR 36108) and to the June 17, 2013 changes to Part 225.79 of the DFARS PGI–225 (Foreign Acquisition). No change was made to the text as a result of this comment.

12. Comment: Three respondents claimed that the proposed rule is ineffective as a way to respond to 2004 and 2007 DOE Inspector General (IG) and 2011 Government Accountability Office (GAO) reports on DOE contractor non-compliance with export laws.

Response: The rule responds to DOE IG and GAO recommendations in the cited reports for DOE to provide specific export control guidance to DOE contractors. In particular, the 2007 DOE IG report recommended that DOE ''ensure that export control guidance is disseminated and implemented throughout the complex.'' To implement that recommendation, the IG report stated that ''NNSA management should expedite action, such as issuing a directive or modifying the Department of Energy Acquisition Regulation (DEAR), to fully implement the open recommendation.'' The 2011 GAO report repeated its prior recommendations for DOE to provide guidance to its contractors. The proposed rule is in direct response to the DOE IG recommendation to modify the DEAR, as well as the recommendations in the GAO report. No change was made to the text as a result of this comment.

13. Comment: Two respondents claimed that the proposed rule unfairly asks Contracting Officers to make export control decisions for which they are not trained. One respondent proposed rewording the requirement for Contracting Officers to insert the export control clause as follows: ''The Contracting Officer shall insert the clause at 952.225–71, Compliance with export control laws, regulations and directives (Export Clause), in all solicitations and contracts.''

Response: The purpose of the new rule is to set forth the responsibilities of DOE contractors and DOE Contracting Officers concerning contractor compliance with export-controlled activities. Contracting Officers are required to include the Export Clause at DEAR 952.225–71 or DEAR 970.5225–1 in solicitations and contracts that would involve export-controlled activities. While the rule has been revised to be applicable to ''all solicitations and contracts,'' export control laws would not be applicable to solicitations and contracts that do not involve export-controlled activities. As noted above, the revised language is similar to the policy approach taken DoD.

14. Comment: Nine respondents claimed that certain reporting requirements included in the Export Clauses would unduly burden DOE contractors because the requirement of a timely, written notification of export controls and compliance for DOE contracts would be an overbroad approach to ensuring export control compliance. Also, the requirement to flow down the reporting requirement would impose administrative and audit burdens on contractors.

Response: The final rule removes the requirements for a contractor to notify the DOE Contracting Officer when the contract may require export activities and for a contractor to assure the DOE Contracting Officer of its ability to comply with U.S. export laws and regulations. The reporting and notification requirements in the proposed rule were not required by any law or regulation, or recommended by any auditors. The purpose of the Export Clauses is to clarify that DOE contractors should consult appropriate export licensing agencies, and not DOE Contracting Officers, with questions regarding compliance with export-controlled activities. The reporting and notification requirements were removed from the rule to avoid any implication that DOE Contracting Officers have any export compliance responsibilities.

15. Comment: Two respondents were concerned about the impact on small business subcontractors and universities.

Response: U.S. export control laws and regulations already apply to activities conducted by small businesses and by universities that have DOE contracts, so there would be no substantive change regarding export control requirements applicable to these entities. No change was made to the text as a result of this comment.

16. Comment: Three respondents claimed that the proposed rule is not consistent with National Security Decision Directive (NSDD) 189 because ''products'' most often generated and disseminated while performing fundamental research are scientific findings excluded from export regulations under the ''Fundamental Research Exclusion'' set forth in NSDD–189 and the exclusion of fundamental research from export controls in EAR and ITAR provisions.

Response: NSDD 189 establishes a national policy that, to the maximum extent possible, the products of fundamental research shall remain unrestricted. NSDD 189 provides that no restrictions may be placed upon the conduct or reporting of federally funded fundamental research that has not received national security classification, except as provided in applicable U.S. statutes. As a result, contracts confined to the performance of unclassified fundamental research generally do not involve any export-controlled activities. NSDD 189 does not take precedence over statutes. As it clearly states in the directive, NSDD 189 does not exempt any research from statutes that apply to export control laws and regulations. In addition, NSDD 189 is focused on the products of fundamental research and does not exempt access to export-controlled technology used or generated during the conduct of fundamental research. The final rule therefore is consistent with NSDD–189 regarding fundamental research because it does not have an impact on the NSDD–189 exemption for fundamental research and it does not modify restrictions already imposed by U.S. export control laws and regulations on research.

DFARS PGI–225.79 (revised June 17, 2013) and [the final rule on the release of fundamental research information in DFARS 252.204–7000 (August 8, 2013) address release of fundamental research information]. Note that the revised

DFARS PGI–225 places reporting requirements on contractors who want to release information that they have determined to be the product of fundamental research. This final rule does not place any reporting requirements on the release of fundamental research by DOE contractors.

17. Comment: Two respondents questioned the scope of the Export Restriction Notice requirement.

Response: The Export Restriction Notice requirement has been removed from the final rule because requirements for the use of such a notice are defined in 41 CFR 109 and do not need to be restated in this rule.

18. Comment: Three respondents recommended that DOE would be better served by providing educational materials to contractors to increase export compliance awareness.

Response: The purpose of the new rule is to direct DOE contractors to seek guidance from and to communicate with export licensing officers at appropriate export licensing agencies, and not to ask for export control compliance assistance from DOE Contracting Officers. Compliance training offices of Department of Commerce, Department of State and other agencies provide appropriate training on their respective export regulations. No change was made to the text as a result of this comment.

19. Comment: Two respondents believed that DOE may inadvertently assume liability because of requirements in the Export Clauses should a contractor be in non-compliance with export control requirements.

Response: DOE will not assume any liability due to inclusion of the Export Clauses in contracts or for contractor noncompliance with export control requirements. No change was made to the text as a result of this comment.

20. Comment: Eight respondents claimed that the proposed rule potentially increases DOE contractors' risk by specifically listing regulations in the contract. They also were concerned that contractors could be liable under the False Claims Act and other laws for their actions or for those of their subcontractors. If the contractor is not in compliance with export control regulations, it may also be subject to Qui Tam penalties, and the rule would make failure to comply with export regulations a contractual obligation. This liability may be assumed by the M&O contractor for all of its subcontractors, including lower-tier subcontractors.

Response: The Export Clauses in the final rule do not require reporting or written assurances. Contractors will not assume new liabilities due to insertion of the Export Clauses in DOE contracts.

21. Comment: One respondent claimed that the proposed rule potentially increases DOE contractors' risk by requiring the contractor to identify specific aspects of the contract governed by export laws.

Response: For the reasons stated previously, reporting and written assurance requirements have been removed from the final rule.

22. Comment: One respondent claimed that adoption of the proposed regulation would increase costs for DOE procurements.

Response: For the reasons stated previously, reporting requirements and written assurances have been removed from the final rule. The only *de minimis* costs associated with the final rule are costs to add the Export Clauses to solicitations and contracts. No further change was made to the text as a result of this comment.

23. Comment: One respondent believed that the rule affects 10 CFR part 810 procedures for contractors subject to that regulation.

Response: The proposed rule does not affect implementation of 10 CFR part 810 with respect to DOE program activities. No change was made to the text as a result of this comment.

24. Comment: One respondent claimed that DOE Contracting Officers will be required to submit all DOE contracts to the Office of Nonproliferation and International Security (NIS) of the National Nuclear Security Administration for 10 CFR part 810 review.

Response: The reporting requirements have been removed from the revised rule. The rule does not place any requirements on DOE Contracting Officers to submit contracts to the office now called the Office of Nonproliferation and Arms Control for 10 CFR part 810 review. No change was made to the text as a result of this comment.

25. Comment: Two respondents asked that this rule to be pursued in conjunction with the revised 10 CFR part 810.

Response: The final rule amending 10 CFR part 810 (part 810) was issued on February 23, 2015. 80 FR 9359 (Feb. 23, 2014). The purpose of that final rule and this final rule are different. Part 810 controls the export of unclassified nuclear technology and assistance, and is one of the export rules that may apply to contractors. It was revised to, among other things, reflect current global civil nuclear trade practices. The purpose of this rule final is to direct DOE contractors to seek guidance from and to communicate with export licensing officers at export licensing agencies regarding export rules such as 10 CFR part 810. No change was made to the text as a result of this comment.

26. Comment: Two respondents stated that the meaning of ''transfer'' is not clear.

Response: References to ''transfers'' have been removed from the final rule.

27. Comment: One respondent stated that the list of items to be transferred that are subject to the Notice is ambiguous.

Response: The Export Restriction Notice has been removed from the rule.

28. Comment: One respondent pointed out that DOE cites obsolete and unavailable references with regard to DoD directives. For instance, DOE lists DOE Order 580.1A which directs the reader to follow requirements in a DoD Demilitarization Manual 4160.21–M–1, that was cancelled and replaced. In addition, the replacement (DoD 4160.28–M series) directs users to obtain disposal guidance for ITAR items from Web sites that are available only to DoD components or those with .mil email addresses.

Response: References to specific DOE Orders in the rule have been removed. References in the NOPR were current at the time that it was published.

29. Comment: Six respondents recommended that the rule more closely follow the DoD example in the revised DFARS.

Response: The final rule has been revised consistent with June 17, 2013, changes to sections 225.79 and 252.225–7048 of the DFARS and the DFARS PGI–225.

30. Comment: One respondent disagreed with the implication in the Export Restriction Notice that all items are subject to export controls.

Response: The Export Restriction Notice has been removed from the final rule. As noted above, the phrase ''subject to export controls'' has been removed from the Export Clauses.

III. Procedural Requirements

A. Review Under Executive Orders 12866 and 13563

Today's regulatory action has been determined not to be a ''significant regulatory action'' under Executive Order 12866, ''Regulatory Planning and Review,'' (58 FR 51735, October 4, 1993). Accordingly, this rule is not subject to review under the Executive Order by the Office of Information and Regulatory Affairs (OIRA) of the Office of Management and Budget (OMB).

DOE has also reviewed this regulation pursuant to Executive Order 13563, issued on January 18, 2011 (76 FR 3281 (Jan. 21, 2011)). Executive Order 13563 is supplemental to, and explicitly reaffirms the principles, structures, and definitions governing, regulatory review established in Executive Order 12866. To the extent permitted by law, agencies are required by Executive Order 13563 to: (1) Propose or adopt a regulation only upon a reasoned determination that its benefits justify its costs (recognizing that some benefits and costs are difficult to quantify); (2) tailor regulations to impose the least burden on society, consistent with obtaining regulatory objectives, taking into account, among other things, and to the extent practicable, the costs of cumulative regulations; (3) select, in choosing among alternative regulatory approaches, those approaches that maximize net benefits (including potential economic, environmental, public health and safety, and other advantages; distributive impacts; and equity); (4) to the extent feasible, specify performance objectives, rather than specifying the behavior or manner of compliance that regulated entities must adopt; and (5) identify and assess available alternatives to direct regulation, including providing economic incentives to encourage the desired behavior, such as user fees or marketable permits, or providing information upon which choices can be made by the public.

DOE emphasizes as well that Executive Order 13563 requires agencies to use the best available techniques to quantify anticipated present and future benefits and costs as accurately as possible. In its guidance, the Office of Information and Regulatory Affairs has emphasized that such techniques may include identifying changing future compliance costs that might result from technological innovation or anticipated behavioral changes. DOE believes that today's final rule is consistent with these principles, including the requirement that, to the extent permitted by law, agencies adopt a regulation only upon a reasoned determination that its benefits justify its costs and, in choosing among alternative regulatory approaches, those approaches maximize net benefits.

B. Review Under Executive Order 12988

With respect to the review of existing regulations and the promulgation of new regulations, section 3(a) of Executive Order 12988, ''Civil Justice Reform,'' 61 FR 4729 (February 7, 1996), imposes on Executive agencies the general duty to adhere to the following requirements: (1) Eliminate drafting errors and ambiguity; (2) write regulations to minimize litigation; and (3) provide a clear legal standard for affected conduct rather than a general standard and promote simplification and burden reduction.

With regard to the review required by section 3(a), section 3(b) of Executive Order 12988 specifically requires that Executive agencies make every reasonable effort to ensure that the regulation: (1) Clearly specifies the preemptive effect, if any; (2) clearly specifies any effect on existing Federal law or regulation; (3) provides a clear legal standard for affected conduct while promoting simplification and burden reduction; (4) specifies the retroactive effect, if any; (5) adequately defines key terms; and (6) addresses other important issues affecting clarity and general draftsmanship under any guidelines issued by the Attorney General. Section 3(c) of Executive Order 12988 requires Executive agencies to review regulations in light of applicable standards in section 3(a) and section 3(b) to determine whether they are met or it is unreasonable to meet one or more of them. DOE has completed the required review and determined that, to the extent permitted by law; these proposed regulations meet the relevant standards of Executive Order 12988.

C. Review Under the Regulatory Flexibility Act

The Regulatory Flexibility Act (5 U.S.C. 601 *et seq.)* requires preparation of a regulatory flexibility analysis for any rule that by law must be proposed for public comment, unless the agency certifies that the rule, if promulgated, will not have a significant economic impact on a substantial number of small entities.

As required by Executive Order 13272, ''Proper Consideration of Small Entities in Agency Rulemaking,'' 67 FR 53461 (August 16, 2002), DOE published procedures and policies on February 19, 2003, to ensure that the potential impacts of its rules on small entities are properly considered during the rulemaking process. 68 FR 7990 (February 19, 2003), DOE has made its procedures and policies available on the Office of the General Counsel's Web site (*http://energy.gov/gc/office-general-counsel*).

DOE certifies that this rule would not have a significant impact on a substantial number of small entities because the rule is intended only to recognize existing export control compliance obligations and to clarify the role of DOE and its contracting officers in relation to these requirements. The rule itself does not impose any new requirements on manufacturers. In addition, DOE notes that the reporting requirements referenced in the proposed rule have been eliminated from the final rule for the reasons discussed in response to the comments received on this issue. DOE transmitted this certification to the Small Business Administration (SBA) as required by 5 U.S.C. 605(b).

D. Review Under the Paperwork Reduction Act

This final rule does not impose a collection of information requirement subject to the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.* DOE's procurement reporting and recordkeeping burdens have been approved under OMB Control No. 1910–4100.

E. Review Under the National Environmental Policy Act

DOE has concluded that promulgation of this final rule falls into a class of actions which would not individually or cumulatively have significant impact on the human environment, as determined by DOE's regulations (10 CFR part 1021, subpart D) implementing the National Environmental Policy Act (NEPA) of 1969 (42 U.S.C. 4321 *et seq.*). Specifically, this final rule is categorically excluded from NEPA review because the amendments to the DEAR are strictly procedural (categorical exclusion A6). Therefore, this final rule does not require an environmental impact statement or environmental assessment pursuant to NEPA.

F. Review Under Executive Order 13132

Executive Order 13132, 64 FR 43255 (August 4, 1999), imposes certain requirements on agencies formulating and implementing policies or regulations that preempt State law or that have federalism implications. Agencies are required to examine the constitutional and statutory authority supporting any action that would limit the policymaking discretion of the States and carefully assess the necessity for such actions. DOE has examined today's rule and has determined that it does not preempt State law and does 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. No further action is required by Executive Order 13132.

G. Review Under the Unfunded Mandates Reform Act of 1995

The Unfunded Mandates Reform Act of 1995 (Pub. L. 104–4) generally requires a Federal agency to perform a detailed assessment of costs and benefits of any rule imposing a Federal Mandate with costs to State, local or tribal governments, or to the private sector, of $100 million or more. This rulemaking does not impose a Federal mandate on State, local or tribal governments or on the private sector.

H. Review Under the Treasury and General Government Appropriations Act, 1999

Section 654 of the Treasury and General Government Appropriations Act, 1999 (Pub. L. 105–277), requires Federal agencies to issue a Family Policymaking Assessment for any rule or policy that may affect family well being. This rule will have no impact on family well-being. Accordingly, DOE has concluded that it is not necessary to prepare a Family Policymaking Assessment.

I. Review Under Executive Order 13211

Executive Order 13211, ''Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use'', 66 FR 28355 (May 22, 2001), requires Federal agencies to prepare and submit to the Office of Information and Regulatory Affairs (OIRA), Office of Management and Budget, a Statement of Energy Effects for any significant energy action. A ''significant energy action'' is defined as any action by an agency that promulgates or is expected to lead to promulgation of a final rule, and that: (1) Is a significant regulatory action under Executive Order 12866, or any successor order; and (2) is likely to have a significant adverse effect on the supply, distribution, or use of energy, or (3) is designated by the Administrator of OIRA as a significant energy action. For any proposed significant energy action, the agency must give a detailed statement of any adverse effects on energy supply, distribution or use should the proposal be implemented, and of reasonable alternatives to the action and their expected benefits on energy supply, distribution and use. Today's rule is not a significant energy action. Accordingly, DOE has not prepared a Statement of Energy Effects.

J. Review Under the Treasury and General Government Appropriations Act, 2001

The Treasury and General Government Appropriations Act, 2001 (44 U.S.C. 3516, note) provides for agencies to review most disseminations of information to the public under implementing guidelines established by each agency pursuant to general guidelines issued by OMB. OMB's guidelines were published at 67 FR 8452 (February 22, 2002), and DOE's guidelines were published at 67 FR 62446 (October 7, 2002). DOE has reviewed today's notice under the OMB and DOE guidelines and has concluded that it is consistent with applicable policies in those guidelines.

K. Review Under Executive Order 13609

Executive Order 13609 of May 1, 2012, ''Promoting International Regulatory Cooperation,'' requires that, to the extent permitted by law and consistent with the principles and requirements of Executive Order 13563 and Executive Order 12866, each Federal agency shall:

(a) If required to submit a Regulatory Plan pursuant to Executive Order 12866, include in that plan a summary of its international regulatory cooperation activities that are reasonably anticipated to lead to significant regulations, with an explanation of how these activities advance the purposes of Executive Order 13563 and this order;

(b) Ensure that significant regulations that the agency identifies as having significant international impacts are designated as such in the Unified Agenda of Federal Regulatory and Deregulatory Actions, on RegInfo.gov, and on Regulations.gov;

(c) In selecting which regulations to include in its retrospective review plan, as required by Executive Order 13563, consider:

(i) Reforms to existing significant regulations that address unnecessary differences in regulatory requirements between the United States and its major trading partners, consistent with section 1 of this order, when stakeholders provide adequate information to the agency establishing that the differences are unnecessary; and

(ii) Such reforms in other circumstances as the agency deems appropriate; and

(d) For significant regulations that the agency identifies as having significant international impacts, consider, to the extent feasible, appropriate, and consistent with law, any regulatory approaches by a foreign government that the United States has agreed to consider under a regulatory cooperation council work plan.

DOE has reviewed this final rule under the provisions of Executive Order 13609 and determined that the rule complies with all requirements set forth in the order.

L. Approval by the Office of the Secretary of Energy

The Office of the Secretary of Energy has approved issuance of this final rule.

M. Congressional Notification

As required by 5 U.S.C. 801, DOE will report to Congress on the promulgation of this rule prior to its effective date. The report will state that it has been determined that the rule is not a ''major rule'' as defined by 5 U.S.C. 804(2).

List of Subjects in 48 CFR Parts 925, 952 and 970

Government procurement.

Issued in Washington, DC, on October 8, 2015.

Patrick Ferraro,

Director, Office of Acquisition Management, Department of Energy.

For reasons set out in the preamble, the DOE is amending Chapter 9 of Title 48 of the Code of Federal Regulations as set forth below.

PART 925—FOREIGN ACQUISITION

■ 1. The authority citation for part 925 continues to read as follows:

Authority: 42 U.S.C. 7101 *et seq.,* and 50 U.S.C. 2401 *et seq.*

■ 2. Subpart 925.71 is added to part 925 to read as follows:

Subpart 925.71—Export Control

Subpart 925.71—Export Control

925.7100 Scope of subpart.

This subpart implements Department of Energy (DOE) requirements for contractors concerning compliance with U.S. export control laws and regulations.

925.7101 Policy.

(a) DOE and its contractors must comply with all applicable U.S. export control laws and regulations.

(b) Export control laws and regulations include, but are not limited to, the Atomic Energy Act of 1954 (42 U.S.C. 2011 *et seq.*), as amended; the Arms Export Control Act (22 U.S.C. 2751 *et seq.*); the Export Administration Act of 1979 (50 U.S.C. app. 2401 *et seq.*), as continued under the International Emergency Economic Powers Act (Title II of Pub. L. 95–223, 91 Stat. 1626, October 28, 1977; 50 U.S.C. 1701 *et seq.*); Trading with the Enemy Act (50 U.S.C. App. 5(b), as amended by the Foreign Assistance Act of 1961); Assistance to Foreign Atomic Energy Activities (Title 10 of the Code of Federal Regulations (CFR) Part 810); Export Administration Regulations (15 CFR parts 730 through 774); International Traffic in Arms Regulations (22 CFR parts 120 through 130); Export and Import of Nuclear Equipment and Material (10 CFR part 110); and regulations administered by the Office of Foreign Assets Control of the Department of the Treasury (31 CFR parts 500 through 598).

(c) Contractors seeking guidance on how to comply with export control laws and regulations should review the illustrative list of laws and regulations set forth in Clause 952.225–71. Contractors also may contact the agencies responsible for administration of export laws or regulations applicable to a particular export (*e.g.,* Departments of State, Commerce, Treasury and Energy, or the Nuclear Regulatory Commission).

(d) DOE Contracting Officers will not answer contractor questions regarding how to comply with U.S. export laws and regulations. Contracting Officers should direct contractors to the export laws, regulations, and agencies cited in the Export Clause at section 952.225–71 of this subpart.

(e) It is the contractor's responsibility to comply with all applicable export control laws and regulations. This responsibility exists independent of, and is not established or limited by, this subpart.

925.7102 Contract clause.

The Contracting Officer shall insert the clause at 952.225–71, Compliance with Export Control Laws and Regulations (Export Clause), in all solicitations and contracts.

PART 952—SOLICITATION PROVISIONS AND CONTRACT CLAUSES

■ 3. The authority citation for part 952 continues to read as follows:

Authority: 42 U.S.C. 2201; 2282a; 2282b; 2282c; 42 U.S.C. 7101 *et seq.;* 50 U.S.C. 2401 *et seq.*

■ 4. Section 952.225–71 is added to read as follows:

952.225–71 Compliance with export control laws and regulations (Export Clause)

As prescribed in 925.7102, use the following clause:

COMPLIANCE WITH EXPORT CONTROL LAWS AND REGULATIONS (NOV 2015)

(a) The Contractor shall comply with all applicable export control laws and regulations.

(b) The Contractor's responsibility to comply with all applicable export control laws and regulations exists independent of, and is not established or limited by, the information provided by this clause.

(c) Nothing in the terms of this contract adds to, changes, supersedes, or waives any of the requirements of applicable Federal laws, Executive Orders, and regulations, including but not limited to—

(1) The Atomic Energy Act of 1954 (42 U.S.C. 2011 *et seq.*), as amended;

(2) The Arms Export Control Act (22 U.S.C. 2751 *et seq.*);

(3) The Export Administration Act of 1979 (50 U.S.C. app. 2401 *et seq.*), as continued under the International Emergency Economic Powers Act (Title II of Pub. L. 95–223, 91 Stat. 1626, October 28, 1977; 50 U.S.C. 1701 *et seq.*);

(4) Trading with the Enemy Act (50 U.S.C. App. 5(b), as amended by the Foreign Assistance Act of 1961);

(5) Assistance to Foreign Atomic Energy Activities (10 CFR part 810);

(6) Export and Import of Nuclear Equipment and Material (10 CFR part 110);

(7) International Traffic in Arms Regulations (ITAR) (22 CFR parts 120 through 130);

(8) Export Administration Regulations (EAR) (15 CFR Parts730 through 774); and

(9) The regulations administered by the Office of Foreign Assets Control of the Department of the Treasury (31 CFR parts 500 through 598).

(d) In addition to the Federal laws and regulations cited above, National Security Decision Directive (NSDD) 189, National Policy on the Transfer of Scientific, Technical, and Engineering Information, establishes a national policy that, to the maximum extent possible, the products of fundamental research shall remain unrestricted. NSDD 189 provides that no restrictions may be placed upon the conduct or reporting of federally funded fundamental research that has not received national security classification, except as provided in applicable U.S. statutes. As a result, contracts confined to the performance of unclassified fundamental research generally do not involve any export-controlled activities.

NSDD 189 does not take precedence over statutes. NSDD 189 does not exempt any research from statutes that apply to export controls such as the Atomic Energy Act, as amended; the Arms Export Control Act; the Export Administration Act of 1979, as amended; or the U.S. International Emergency Economic Powers Act, or regulations that implement parts of those statutes (*e.g.,* the ITAR, the EAR, 10 CFR part 110 and 10 CFR part 810). Thus, if items (*e.g.,* commodities, software or technologies) that are controlled by U.S. export control laws or regulations are used to conduct research or are generated as part of the research efforts, export control laws and regulations apply to the controlled items.

(e) The Contractor shall include the substance of this clause, including this paragraph (e), in all solicitations and subcontracts.

PART 970—DOE MANAGEMENT AND OPERATING CONTRACTS

■ 5. The authority citation for part 970 continues to read as follows:

Authority: 42 U.S.C. 2201; 2282a; 2282b; 2282c; 42 U.S.C. 7101 *et seq.;* 50 U.S.C. 2401 *et seq.*

■ 6. Subpart 970.25 is revised to read as follows:

Subpart 970.25—Foreign Acquisition

Subpart 970.25—Foreign Acquisition

970.2570 Buy American Act.

970.2570–1 Contract clause.

Contracting officers shall insert the clauses at 48 CFR 52.225–1, Buy American Act—Supplies, and 48 CFR 52.225–9, Buy American Act—Construction Materials, in management and operating contracts. The clause at 48 CFR 52.225–1 shall be modified in paragraph (d) of this section by substituting the word ''use'' for the word ''deliver.''

970.2571 Export control.

970.2571–1 Scope of subpart.

This subpart implements DOE requirements for DOE management and operating contractors concerning compliance with U.S. export control laws and regulations.

970.2571–2 Policy.

(a) DOE and its contractors must comply with all applicable export control laws and regulations.

(b) Export control laws and regulations include, but are not limited to, the Atomic Energy Act of 1954, as amended; the Arms Export Control Act (22 U.S.C. 2751 *et seq.*); the Export Administration Act of 1979 (50 U.S.C. app. 2401 *et seq.*), as continued under the International Emergency Economic Powers Act (Title II of Pub. L. 95–223, 91 Stat. 1626, October 28, 1977; 50 U.S.C. 1701 *et seq.*); Trading with the Enemy Act (50 U.S.C. App. 5(b), as amended by the Foreign Assistance Act of 1961); Assistance to Foreign Atomic Energy Activities (Title 10 of the Code of Federal Regulations (CFR) Part 810);

Export Administration Regulations (15 CFR parts 730 through 774); International Traffic in Arms Regulations (22 CFR parts 120 through 130); Export and Import of Nuclear Equipment and Material (10 CFR part 110); and regulations administered by the Office of Foreign Assets Control of the Department of the Treasury (31 CFR parts 500 through 598).

(c) Contractors seeking guidance on how to comply with export control requirements should review the illustrative list of laws and regulations applicable to the export of unclassified information, materials, technology, equipment or software set forth in clause 970.5225–1. Contractors also may contact the agencies responsible for administration of export laws and regulations applicable to a particular export (*e.g.,* Departments of State, Commerce, Treasury and Energy, or the Nuclear Regulatory Commission).

(d) The contracting officer will not answer any questions a contractor may ask regarding how to comply with export regulations. If asked, the contracting officer should direct the contractor to export regulations and agencies cited in the Export Clause at 970.5225–1.

(e) It is the contractor's responsibility to comply with all applicable U.S. export control laws and regulations. This responsibility exists independent of, and is not established or limited by, this subpart.

970.2571–3 Contract clause.

The Contracting Officer shall insert the clause at 970.5225–1, Compliance with Export Control Laws and Regulations (Export Clause), in all solicitations and contracts.

Subpart 970.52—Solicitation Provisions and Contract Clauses for Management and Operating Contracts

■ 7. Section 970.5225–1 is added to read as follows:

970.5225–1 Compliance with export control laws and regulations (Export Clause).

As prescribed in 970.2571–3, use the following clause:

COMPLIANCE WITH EXPORT CONTROL LAWS AND REGULATIONS (NOV 2015)

(a) The Contractor shall comply with all applicable U.S. export control laws and regulations.

(b) The Contractor's responsibility to comply with all applicable laws and regulations exists independent of, and is not established or limited by, the information provided by this clause.

(c) Nothing in the terms of this contract adds to, changes, supersedes, or waives any of the requirements of applicable Federal laws, Executive Orders, and regulations, including but not limited to—

(1) The Atomic Energy Act of 1954, as amended;

(2) The Arms Export Control Act (22 U.S.C. 2751 *et seq.*);

(3) The Export Administration Act of 1979 (50 U.S.C. app. 2401 *et seq.*), as continued under the International Emergency Economic Powers Act (Title II of Pub. L. 95–223, 91 Stat. 1626, October 28, 1977; 50 U.S.C. 1701 *et seq.*);

(4) Trading with the Enemy Act (50 U.S.C. App. 5(b), as amended by the Foreign Assistance Act of 1961);

(5) Assistance to Foreign Atomic Energy Activities (10 CFR part 810);

(6) Export and Import of Nuclear Equipment and Material (10 CFR part 110);

(7) International Traffic in Arms Regulations (ITAR) (22 CFR parts 120 through 130);

(8) Export Administration Regulations (EAR) (15 CFR parts 730 through 774); and

(9) Regulations administered by the Office of Foreign Assets Control (31 CFR parts 500 through 598).

(d) In addition to the Federal laws and regulations cited above, National Security Decision Directive (NSDD) 189, National Policy on the Transfer of Scientific, Technical, and Engineering Information establishes a national policy that, to the maximum extent possible, the products of fundamental research shall remain unrestricted. NSDD 189 provides that no restrictions may be placed upon the conduct or reporting of federally funded fundamental research that has not received national security classification, except as provided in applicable U.S. statutes. As a result, contracts confined to the performance of unclassified fundamental research generally do not involve any export-controlled activities.

NSDD 189 does not take precedence over statutes. NSDD 189 does not exempt any research from statutes that apply to export controls such as the Atomic Energy Act, as amended; the Arms Export Control Act; the Export Administration Act of 1979, as amended; or the U.S. International Emergency Economic Powers Act; or the regulations that implement those statutes (*e.g.,* the ITAR, the EAR, 10 CFR part 110 and 10 CFR part 810). Thus, if items (*e.g.,* commodities, software or technologies) that are controlled by U.S. export control laws or regulations are used to conduct research or are generated as part of the research efforts, the export control laws and regulations apply to the controlled items.

(e) The Contractor shall include the substance of this clause, including this paragraph (e), in all solicitations and subcontracts.

[FR Doc. 2015–26476 Filed 10–22–15; 8:45 am]

BILLING CODE 6450–01–P

Proposed Rules

Federal Register

Vol. 80, No. 205

Friday, October 23, 2015

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

DEPARTMENT OF ENERGY

10 CFR Parts 429 and 431

[Docket No. EERE–2013–BT–STD–0022]

RIN 1904–AD00

Energy Conservation Program: Energy Conservation Standards for Refrigerated Beverage Vending Machines

AGENCY: Office of Energy Efficiency and Renewable Energy, Department of Energy.

ACTION: Reopening of public comment period.

SUMMARY: On August 19, 2015, the U.S. Department of Energy (DOE) published a notice of proposed rulemaking (NOPR) in the **Federal Register** regarding energy conservation standards for refrigerated beverage vending machines (BVM ECS NOPR). DOE also held a public meeting on September 29, 2015. The comment period was scheduled to end October 19, 2015. After receiving a request for additional time to prepare and submit comments, DOE has decided to reopen the comment period for submitting comments regarding the BVM ECS NOPR. The comment period is reopened through November 23, 2015.

DATES: DOE will accept comments, data, and information in response to the NOPR received no later than November 23, 2015.

ADDRESSES: Any comments submitted must identify the NOPR for Energy Conservation Standards for Refrigerated Beverage Vending Machines, and provide docket number EERE–2013–BT–STD–0022 and/or regulatory information number (RIN) number 1904–AD00. Comments may be submitted using any of the following methods:

1. *Federal eRulemaking Portal: www.regulations.gov.* Follow the instructions for submitting comments.

2. *Email: BVM2013STD0022@ee.doe.gov.* Include the docket number EERE–2013–BT–STD–0022 and/or RIN 1904–AD00 in the subject line of the message.

3. *Mail:* Ms. Brenda Edwards, U.S. Department of Energy, Building Technologies Program, Mailstop EE–5B, 1000 Independence Avenue SW., Washington, DC, 20585–0121. If possible, please submit all items on a CD. It is not necessary to include printed copies.

4. *Hand Delivery/Courier:* Ms. Brenda Edwards, U.S. Department of Energy, Building Technologies Program, 950 L'Enfant Plaza SW., Suite 600, Washington, DC 20024. Telephone: (202) 586–2945. If possible, please submit all items on a CD. It is not necessary to include printed copies.

Docket: The docket, which includes **Federal Register** notices, public meeting attendee lists and transcripts, comments, and other supporting documents/materials, is available for review at regulations.gov. All documents in the docket are listed in the regulations.gov index. However, some documents listed in the index, such as those containing information that is exempt from public disclosure, may not be publicly available.

A link to the docket Web page can be found at: [*www.regulations.gov/#!docketDetail;D=EERE-2013-BT-STD-0022*]. This Web page contains a link to the docket for this notice on the regulations.gov site. The regulations.gov Web page contains instructions on how to access all documents, including public comments, in the docket.

For further information on how to submit a comment or review other public comments and the docket, contact Ms. Brenda Edwards at (202) 586–2945 or by email: *Brenda.Edwards@ee.doe.gov.*

FOR FURTHER INFORMATION CONTACT: John Cymbalsky, U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, Building Technologies Program, EE–5B, 1000 Independence Avenue SW., Washington, DC 20585–0121. Telephone: (202) 287–1692. Email *John.Cymbalsky@ee.doe.govmailto:.*

For legal issues, please contact Ms. Sarah Butler, U.S. Department of Energy, Office of General Counsel, GC–33, 1000 Independence Avenue SW., Washington, DC 20585–0121. Telephone: (202) 586–1777. Email: *Sarah.Butler@hq.doe.gov.*

SUPPLEMENTARY INFORMATION: On August 19, 2015, DOE published a notice of proposed rulemaking (NOPR) in the **Federal Register** regarding energy conservation standards for refrigerated beverage vending machines (BVM ECS NOPR). 80 FR 50462. The notice provided for the submission of written comments by October 19, 2015, and oral comments were also accepted at a public meeting held on September 29, 2015.

DOE received a request from several stakeholders requesting additional time to prepare and submit comments (Docket No. EERE–2013–BT–STD–0022, Royal Vendors, No. 46 at p. 1, NAMA, No. 44 at p. 1, and AMS, No. 43 at p. 1). In response to these requests, DOE is reopening the public comment period to allow interested parties to provide DOE with written comments and data in response to the BVM ECS NOPR.

DOE will consider any comments in response to the BVM ECS NOPR received by midnight of November 23, 2015, and deems any comments received by that time to be timely submitted.

Issued in Washington, DC, on October 15. 2015.

Kathleen B. Hogan,

Deputy Assistant Secretary for Energy Efficiency, Energy Efficiency and Renewable Energy.

[FR Doc. 2015–27001 Filed 10–22–15; 8:45 am]

BILLING CODE 6450–01–P

DEPARTMENT OF ENERGY

10 CFR Part 430

[Docket No. EERE–2014–BT–STD–0031]

RIN 1904–AD20

Energy Conservation Program: Energy Conservation Standards for Residential Furnaces

AGENCY: Office of Energy Efficiency and Renewable Energy, Department of Energy.

ACTION: Reopening of public comment period.

SUMMARY: On September 14, 2015, the U.S. Department of Energy (DOE) published a notice of data availability (NODA) in the **Federal Register** regarding energy conservation standards for residential furnaces (RF ECS NODA). The comment period was scheduled to

end October 14, 2015. After receiving a request for additional time to prepare and submit comments, DOE has decided to reopen the comment period for submitting comments regarding the RF ECS NODA. The comment period is reopened through November 6, 2015.

DATES: DOE will accept comments, data, and information in response to the NODA received no later than November 6, 2015.

ADDRESSES: Any comments submitted must identify the NODA for Energy Conservation Standards for Residential Furnaces, and provide docket number EERE–2014–BT–STD–0031 and/or regulatory information number (RIN) number 1904–AD20. Comments may be submitted using any of the following methods:

1. *Federal eRulemaking Portal: www.regulations.gov.* Follow the instructions for submitting comments.

2. *Email: ResFurnaces2014STD0031@ee.doe.gov* Include the docket number EERE–2014–BT–STD–0031 and/or RIN 1904–AD20 in the subject line of the message.

3. *Mail:* Ms. Brenda Edwards, U.S. Department of Energy, Building Technologies Program, Mailstop EE–2J, 1000 Independence Avenue SW., Washington, DC 20585–0121. If possible, please submit all items on a CD. It is not necessary to include printed copies.

4. *Hand Delivery/Courier:* Ms. Brenda Edwards, U.S. Department of Energy, Building Technologies Program, 950 L'Enfant Plaza SW., Suite 600, Washington, DC 20024. Telephone: (202) 586–2945. If possible, please submit all items on a CD. It is not necessary to include printed copies.

Docket: The docket, which includes **Federal Register** notices, public meeting attendee lists and transcripts, comments, and other supporting documents/materials, is available for review at regulations.gov. All documents in the docket are listed in the regulations.gov index. However, some documents listed in the index, such as those containing information that is exempt from public disclosure, may not be publicly available.

A link to the docket Web page can be found at: [*www.regulations.gov/#!docketDetail;D=EERE-2014-BT-STD-0031*]. This Web page contains a link to the docket for this notice on the regulations.gov site. The regulations.gov Web page contains instructions on how to access all documents, including public comments, in the docket.

For further information on how to submit a comment or review other public comments and the docket, contact Ms. Brenda Edwards at (202) 586–2945 or by email: *Brenda.Edwards@ee.doe.gov.*

FOR FURTHER INFORMATION CONTACT: John Cymbalsky, U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, Building Technologies Program, EE–5B, 1000 Independence Avenue SW., Washington, DC 20585–0121. Telephone: (202) 287–1692. Email *John.Cymbalsky@ee.doe.govmailto:.*

For legal issues, please contact Ms. Johanna Hariharan, U.S. Department of Energy, Office of General Counsel, GC–33, 1000 Independence Avenue SW., Washington, DC 20585–0121. Telephone: (202) 287–6307. Email: *Johanna.Hariharan@hq.doe.gov.*

SUPPLEMENTARY INFORMATION: On September 14, 2015, DOE published a notice of data availability (NODA) in the **Federal Register** regarding energy conservation standards for residential furnaces (RF ECS NODA). 80 FR 55038. The notice requested that interested parties submit written comments by October 14, 2015.

DOE received a joint request from the American Gas Association (AGA) and the American Public Gas Association (APGA) requesting additional time to prepare and submit comments (Docket No. EERE–2014–BT–STD–0031, AGA/APGA, No. 168 at p. 2). In response to this request, DOE is reopening the public comment period to allow interested parties to provide DOE with written comments and data in response to the RF ECS NODA.

DOE will consider any comments in response to the RF ECS NODA received by midnight of November 6, 2015, and deems any comments received by that time to be timely submitted.

Issued in Washington, DC, on October 15, 2015.

Kathleen B. Hogan,

Deputy Assistant Secretary for Energy Efficiency, Energy Efficiency and Renewable Energy.

[FR Doc. 2015–27002 Filed 10–22–15; 8:45 am]

BILLING CODE 6450–01–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 39

[Docket No. FAA–2015–4204; Directorate Identifier 2015–NM–001–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 A300 B4–600, B4–600R, and F4–600R series airplanes, and Model A300 C4–605R Variant F airplanes (collectively called Model A300–600 series airplanes) modified by a particular supplemental type certificate (STC). This proposed AD was prompted by a report of chafing found on the overflow sensor harness of the surge tank, and subsequent contact between the electrical wiring and fuel tank structure. This proposed AD would require a one-time inspection for damage of the outer tank of the overflow sensor harness, and repair if necessary. This proposed AD would also require modification of the sensor harness. We are proposing this AD to prevent chafing of the harness and subsequent contact between the electrical wiring and fuel tank structure, which could result in electrical arcing and a fuel tank explosion.

DATES: We must receive comments on this proposed AD by December 7, 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 Simmonds Precision Products, Inc., A UTC Aerospace Company, 100 Panton Road, Vergennes, Vermont 05491; phone 802–877–2911; fax 802–877–4444; Internet *http://www.utcaerospacesystems.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–2015–4204; 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:
Marc Ronell, Aerospace Engineer, Boston Aircraft Certification Office, FAA, 12 New England Executive Park, Burlington, MA 01803; phone: 781–238–7776; fax: 781–238–7170; email: *marc.ronell@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–2015–4204; Directorate Identifier 2015–NM–001–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, issued EASA Airworthiness Directive 2013–0193, dated August 23, 2013 (referred to after this as the Mandatory Continuing Airworthiness Information, or ''the MCAI''), to correct an unsafe condition for all Airbus Model A300 series airplanes and all Model A300–600 series airplanes.

The MCAI corresponds to FAA AD 2015–03–03, Amendment 39–18099 (80 FR 11101, March 2, 2015), which applies to Airbus Model A300 series airplanes and Model A300–600 series airplanes, all serial numbers, except for airplanes modified by supplemental type certificate ST00092BO (*http://rgl.faa.gov/Regulatory_and_Guidance_Library/rgstc.nsf/0/D41C5AE8E46B4901862574900069E004?OpenDocument&Highlight=st00092bo*).

In AD 2015–03–03, Amendment 39–18099 (80 FR 11101, March 2, 2015), we explained that airplanes that have had the in-tank fuel quantity system modified by STC ST00092BO cannot accomplish the actions required by AD 2015–03–03 by using Airbus Service Bulletin A300–28–6109, Revision 01, dated December 20, 2013.

We also stated that we were considering separate rulemaking to require the procedures and compliance time specified in UTC Aerospace Systems Service Bulletin 300723–28–03 (V–1577), dated October 10, 2014, for airplanes modified by STC ST00092BO. We now have determined that further rulemaking is indeed necessary, and this proposed AD follows from that determination.

Related Service Information Under 1 CFR Part 51

UTC Aerospace Systems has issued Service Bulletin 300723–28–03 (V–1577), Revision 01, dated July 20, 2015. The service information describes procedures for an inspection for damage of the outer tank of the overflow sensor harness, repair, and modification of the sensor harness. 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.

FAA's Determination

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

Proposed AD Requirements

This proposed AD would require accomplishing the actions specified in the service information described previously.

Costs of Compliance

We estimate that this proposed AD affects 65 airplanes of U.S. registry.

We also estimate that it would take about 3 work-hours per product to comply with the inspections required by this proposed AD. The average labor rate is $85 per work-hour. Based on these figures, we estimate the cost of this inspection proposed by this AD on U.S. operators to be $16,575, or $255 per product.

We estimate that it takes about 11 work-hours per product to comply with the modification requirements of this AD. The average labor rate is $85 per work-hour. Required parts cost about $100 per product. Based on these figures, we estimate the cost of this modification on U.S. operators to be $67,275, or $1,035 per product.

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):

Airbus: Docket No. FAA–2015–4204; Directorate Identifier 2015–NM–001–AD.

(a) Comments Due Date

We must receive comments by December 7, 2015.

(b) Affected ADs

None.

(c) Applicability

This AD applies to the Airbus airplanes specified in paragraphs (c)(1), (c)(2), (c)(3), and (c)(4) of this AD; certificated in any category; modified by Simmonds Precision Products, Inc., supplemental type certificate (STC) ST00092BO (*http://rgl.faa.gov/Regulatory_and_Guidance_Library/rgstc.nsf/0/D41C5AE8E46B4901862v574900069E004?OpenDocument&Highlight=st00092bo*).

(1) Model A300 B4–601, B4–603, B4–620, and B4–622 airplanes.

(2) Model A300 B4–605R and B4–622R airplanes.

(3) Model A300 F4–605R and F4–622R airplanes.

(4) Model A300 C4–605R Variant F airplanes.

(d) Subject

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

(e) Reason

This AD was prompted by a report of chafing found on the overflow sensor harness of the surge tank, and subsequent contact between the electrical wiring and fuel tank structure. We are issuing this AD to prevent chafing of the harness and subsequent contact between the electrical wiring and fuel tank structure, which could result in electrical arcing and a fuel tank explosion.

(f) Compliance

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

(g) One-Time Inspection and Repair

Within 12 months after the effective date of this AD: Do the actions required by paragraphs (g)(1), (g)(2), and (g)(3) of this AD, in accordance with the Accomplishment Instructions of UTC Aerospace Systems Service Bulletin 300723–28–03 (V–1577), Revision 01, dated July 20, 2015.

(1) Perform a one-time general visual inspection for damage of the outer tank sensor harness, and if any damage is found on the expando sleeving, before further flight, do a detailed inspection of the underlying wires for exposed conductor wires. If any exposed conductor wire is found, before further flight, replace the outer wing harness assembly.

(2) Install new brackets and re-route the surge tank overflow sensor harness.

(3) Modify the harness protection.

(h) Credit for Previous Actions

This paragraph provides credit for actions required by paragraph (g) of this AD, if those actions were performed before the effective date of this AD using UTC Aerospace Systems Service Bulletin 300723–28–03 (V–1577), dated October 10, 2014. This service information is not incorporated by reference in this AD.

(i) Alternative Methods of Compliance (AMOCs)

(1) The Manager, Boston Aircraft Certification Office (ACO) ANE–150, 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 (j)(1) of this AD.

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

(j) Related Information

(1) For more information about this AD, contact Marc Ronell, Aerospace Engineer, Boston ACO, FAA, 12 New England Executive Park, Burlington, MA 01803; phone: 781–238–7776; fax: 781–238–7170; email: *marc.ronell@faa.gov.*

(2) For service information identified in this AD, contact Simmonds Precision Products, Inc., A UTC Aerospace Company, 100 Panton Road, Vergennes, Vermont 05491; phone 802–877–2911; fax 802–877–4444; Internet *http://www.utcaerospacesystems.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 October 15, 2015.

Jeffrey E. Duven,

Manager, Transport Airplane Directorate, Aircraft Certification Service.

[FR Doc. 2015–26691 Filed 10–22–15; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 39

[Docket No. FAA–2015–3713; Directorate Identifier 2015–NE–23–AD]

RIN 2120–AA64

Airworthiness Directives; Engine Alliance Turbofan Engines

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Notice of proposed rulemaking (NPRM).

SUMMARY: We propose to adopt a new airworthiness directive (AD) for certain Engine Alliance (EA) GP7270 turbofan engines. This proposed AD was prompted by reports of the installation of non-conforming honeycomb seals in the high-pressure compressor (HPC) adjacent to the HPC rotor stage 2 to 5 spool and stage 7 to 9 spool. This proposed AD would require removal and replacement of the affected HPC rotor stage 2 to 5 and stage 7 to 9 spools. We are proposing this AD to prevent failure of the HPC rotor stage 2 to 5 and stage 7 to 9 spools, which could lead to uncontained engine failure and damage to the airplane.

DATES: We must receive comments on this proposed AD by December 22, 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:* Deliver to Mail address above between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays.

For service information identified in this proposed AD, contact Engine Alliance, 400 Main St., East Hartford, CT 06108, M/S 169–10, phone: 800–565–0140; email: *help24@pw.utc.com;*

Web site: *www.enginealliance portal.com.* You may view this service information at the FAA, Engine & Propeller Directorate, 12 New England Executive Park, Burlington, MA. For information on the availability of this material at the FAA, call 781–238–7125.

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–2015–3713; 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: Martin Adler, Aerospace Engineer, Engine & Propeller Directorate, FAA, 12 New England Executive Park, Burlington, MA 01803; phone: 781–238–7157; fax: 781–238–7199; email: *martin.adler@faa.gov.*

SUPPLEMENTARY INFORMATION:

Comments Invited

We invite you to send any written relevant data, views, or arguments about this proposal. Send your comments to an address listed under the **ADDRESSES** section. Include ''Docket No. FAA–2015–3713; Directorate Identifier 2015–NE–23–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 learned from the manufacturer that non-conforming honeycomb seals were installed in the affected HPCs adjacent to the HPC rotor stage 2 to 5 spools and stage 7 to 9 spools. The honeycomb seals in the HPC were machined to an incorrect radial height which resulted in reduced clearances between the honeycomb and the rotating spools. This error could lead to cracks on the spools prior to reaching their full life. This condition, if not corrected, could result in failure of the HPC rotor stage 2 to 5 and stage 7 to 9 spools, which could lead to uncontained engine failure, and damage to the airplane.

Relevant Service Information Under 1 CFR Part 51

Engine Alliance has issued EA Service Bulletin (SB) No. EAGP7–72–327, dated July 21, 2015; and SB No. EAGP7–72–328, dated July 21, 2015. The SBs describe procedures for removal and replacement of HPC rotor stage 2 to 5 spools and HPC rotor stage 7 to 9 spools, respectively. 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 document.

FAA's Determination

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

Proposed AD Requirements

This proposed AD would require removal and replacement of the affected HPC rotor stage 2 to 5 and stage 7 to 9 spools.

Costs of Compliance

We estimate that this proposed AD affects zero engines installed on airplanes of U.S. registry. The average labor rate is $85 per hour. Based on these figures, we estimate the cost of this proposed AD on U.S. operators to be $0.

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 to the extent that it justifies making a regulatory distinction, 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):

Engine Alliance: Docket No. FAA–2015–3713; Directorate Identifier 2015–NE–23–AD.

(a) Comments Due Date

We must receive comments by December 22, 2015.

(b) Affected ADs

None.

(c) Applicability

This AD applies to Engine Alliance (EA) GP7270 turbofan engines with one or both of the following installed:

(1) A high-pressure compressor (HPC) rotor stage 2 to 5 spool, part number (P/N) 382–104–807–0, with a serial number (S/N) listed in EA Service Bulletin (SB) No. EAGP7–72–327, dated July 21, 2015; or

(2) an HPC rotor stage 7 to 9 spool, P/N 2031M90G04, 2031M90G05, or 2031M90G07, with an S/N listed in EA SB No. EAGP7–72–328, dated July 21, 2015.

(d) Unsafe Condition

This AD was prompted by reports of the installation of non-conforming honeycomb seals in the HPC adjacent to the HPC rotor stage 2 to 5 spool and stage 7 to 9 spool. We are issuing this AD to prevent failure of the HPC rotor stage 2 to 5 spools and stage 7 to 9 spools, which could lead to uncontained engine failure and damage to the airplane.

(e) Compliance

Comply with this AD within the compliance times specified, unless already done. Within 30 days after the effective date of this AD or before accumulating 2,100 engine cycles since the last disassembly of the compressor module of the engine, whichever occurs later:

(1) For engines with an HPC rotor stage 2 to 5 spool, P/N 382–104–807–0, installed with a S/N listed in EA SB No. EAGP7–72–327, dated July 21, 2015, do the following:

(i) Remove the HPC rotor stage 2 to 5 spool from service and replace with a part eligible for installation.

(ii) Remove and replace the honeycomb seals on the HPC stage 5 vanes.

(2) For engines with an HPC rotor stage 7 to 9 spool, P/N 2031M90G04, 2031M90G05, or 2031M90G07 installed with an S/N listed in EA SB No. EAGP7–72–328, dated July 21, 2015, do the following:

(i) Remove the HPC rotor stage 7 to 9 spool from service and replace with a part eligible for installation.

(ii) Remove and replace the honeycomb seals on the HPC stage 6, stage 7, and stage 8 vanes.

(f) Alternative Methods of Compliance (AMOCs)

The Manager, Engine Certification Office, may approve AMOCs for this AD. Use the procedures found in 14 CFR 39.19 to make your request. You may email your request to: *ANE-AD-AMOC@faa.gov.*

(g) Related Information

(1) For more information about this AD, contact Martin Adler, Aerospace Engineer, Engine & Propeller Directorate, FAA, 12 New England Executive Park, Burlington, MA 01803; phone: 781–238–7157; fax: 781–238–7199; email: *martin.adler@faa.gov.*

(2) EA SBs No. EAGP7–72–327, dated July 21, 2015; and No. EAGP7–72–328, dated July 21, 2015 can be obtained from EA using the contact information in paragraph (g)(3) of this proposed AD.

(3) For service information identified in this AD, contact Engine Alliance, 400 Main St., East Hartford, CT 06108, M/S 169–10, phone: 800–565–0140; email: *help24@pw.utc.com;* Web site: *www.enginealliance portal.com.*

(4) You may view this service information at the FAA, Engine & Propeller Directorate, 12 New England Executive Park, Burlington, MA. For information on the availability of this material at the FAA, call 781–238–7125.

Issued in Burlington, Massachusetts, on October 16, 2015.

Colleen M. D'Alessandro,

Directorate Manager, Engine & Propeller Directorate, Aircraft Certification Service.

[FR Doc. 2015–26755 Filed 10–22–15; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 39

[Docket No. FAA–2015–4202; Directorate Identifier 2014–NM–016–AD]

RIN 2120–AA64

Airworthiness Directives; Airbus Airplanes

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Notice of proposed rulemaking (NPRM).

SUMMARY: We propose to supersede Airworthiness Directive (AD) 2012–18–12, for certain Airbus Model A318, A319, and A320 series airplanes. AD 2012–18–12 currently requires modifying the off-wing escape slide (OWS) enclosures on the left-hand (LH) side and right-hand (RH) side of the fuselage. Since we issued AD 2012–18–12, we have received reports that additional OWS part numbers have been affected. This proposed AD would retain the requirements of AD 2012–18–12 and expand the applicability to all Airbus Model A318, A319, and A320 series airplanes. We are proposing this AD to prevent off-wing exits on the LH and RH sides of the fuselage from becoming inoperative, which, during an emergency, could impair the safe evacuation of occupants, possibly resulting in personal injuries.

DATES: We must receive comments on this proposed AD by December 7, 2015.

ADDRESSES: You may send comments 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 Airbus service information identified in this proposed AD, contact Airbus, Airworthiness Office—EIAS, 1 Rond Point Maurice Bellonte, 31707 Blagnac Cedex, France; telephone +33 5 61 93 36 96; fax +33 5 61 93 44 51; email *account.airworth-eas@airbus.com;* Internet *http://www.airbus.com.* For Air Cruisers service information identified in this proposed AD, contact Air Cruisers Company, Cage Code 70167, 1747 State Route 34, Wall Township, NJ 07727–3935; telephone 732–681–3527; fax 732–681–9163; Internet *http://www.zodiacaerospace.com/en/our-activities/aerosafety/zodiac-evacuation-systems.* 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–2015–4202; 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: Sanjay Ralhan, Aerospace Engineer, International Branch, ANM–116, Transport Airplane Directorate, FAA, 1601 Lind Avenue SW., Renton, WA 98057–3356; telephone 425–227–1405; 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–2015–4202; Directorate Identifier 2014–NM–016–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

On August 31, 2012, we issued AD 2012–18–12, Amendment 39–17189 (77 FR 57003, September 17, 2012). AD 2012–18–12 requires actions intended to address an unsafe condition on certain Airbus Model A318, A319, and A320 series airplanes.

Since we issued AD 2012–18–12, Amendment 39–17189 (77 FR 57003, September 17, 2012), we received reports that additional OWS part numbers have been affected which requires expanding the applicability to all Airbus Model A318, A319, and A320 series airplanes.

The European Aviation Safety Agency (EASA), which is the Technical Agent for the Member States of the European Union, has issued EASA Airworthiness Directive 2014–0025R1, dated May 26, 2014 (referred to after this as the Mandatory Continuing Airworthiness Information, or ''the MCAI''), to correct an unsafe condition on all Airbus Model A318, A319, and A320 series airplanes. The MCAI states:

> One operator reported a torn out aspirator during scheduled deployment (for on ground testing purposes) of the Left Hand (LH) off-wing [escape] slide (OWS). Investigation results revealed that the aspirator of the OWS system interfered with the extrusion lip of the OWS enclosure during the initial stage of the deployment sequence.
>
> This condition, if not corrected, could lead to an off-wing exit, either LH or Right Hand (RH), becoming unserviceable, which, during an emergency situation, could impair the safe evacuation of occupants, possibly resulting in personal injuries.
>
> To address this potential unsafe condition, Airbus issued Service Bulletin (SB) A320–25–1649 containing modification instructions for certain part number (P/N) OWS enclosures. Consequently, EASA issued [EASA] AD 2010–0210 [(*http://ad.easa.europa.eu/ad/2010-0210*)] which corresponds to FAA AD 2012–18–12, Amendment 39–17189 (77 FR 57003, September 17, 2012)] to require modification of the affected OWS enclosures.
>
> Since that [EASA] AD was issued, several other OWS P/N[s] have been identified as potentially impacted.
>
> For the reason described above, this [EASA] AD retains the requirements of EASA AD 2010–0210, which is superseded, expands the Applicability to all A318, A319 and A320 aeroplanes, and expands the batch of affected P/N[s] prohibited to be installed on an aeroplane.
>
> For the reason described above, EASA issued AD 2014–0025, retaining the requirements of EASA AD 2010–0210, which was superseded, expanding the Applicability to all A318, A319 and A320 aeroplanes, and expanding the batch of affected P/N[s] prohibited to be installed on an aeroplane. That [EASA] AD also retained the requirements of * * * [an AD, which was superseded], which required modification of the OWS and its aspirator.
>
> This [EASA] AD is revised to amend paragraphs (1) and (3) to restore the original applicability of DGAC France AD 2001–380 and EASA AD 2010–0210, respectively, and to correct paragraph (2) to give credit for certain production modifications that were equivalent for the in-service actions previously required by DGAC France AD 2001–380.

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–2015–4202.

Related Service Information Under 1 CFR Part 51

Airbus has issued the following service information.

- Airbus Service Bulletin A320–25–1156, Revision 03, dated December 5, 2001. This service information describes procedures for modifying OWS enclosures having part numbers (P/N) D31865–101, D31865–102, D31865–103, D31865–104, D31865–105, D31865–106, D31865–107, or D31865–108 of certain Airbus Model A319 and A320 series airplanes.
- Airbus Service Bulletin A320–25–1265, Revision 01, dated December 5, 2001. This service information describes procedures for modifying and installing the OWS enclosure on the LH and RH sides of the fuselage on certain Airbus Model A319 and A320 series airplanes.
- Airbus Service Bulletin A320–25–1649, dated February 16, 2010. This service information describes procedures for modifying and installing OWS enclosures having part numbers (P/N) D31865–109, D31865–110, D31865–209, or D31865–210, on the LH and RH sides of the fuselage on certain Airbus Model A318, A319, and A320 series airplanes.

Air Cruisers has issued Service Bulletin A320 004–25–84, Revision 4, dated November 9, 2012. This service information describes procedures for modifying LH and RH OWS.

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 the same type design.

Costs of Compliance

We estimate that this proposed AD affects 851 airplanes of U.S. registry.

The actions required by AD 2012–18–12, Amendment 39–17189 (77 FR 57003, September 17, 2012), and retained in this proposed AD take about 14 work-hours per product, at an average labor rate of $85 per work-hour. Required parts cost $0 per product. Based on these figures, the estimated cost of the actions that are required by AD 2012–18–12 is $1,190 per product.

We also estimate that it would take about 48 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 $0 per product. Based on these figures, we estimate the cost of this proposed AD on U.S. operators to be $3,472,080, or $4,080 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 removing Airworthiness Directive (AD) 2012–18–12, Amendment 39–17189 (77 FR 57003, September 17, 2012), and adding the following new AD:

Airbus: Docket No. FAA–2015–4202; Directorate Identifier 2014–NM–016–AD.

(a) Comments Due Date

We must receive comments by December 7, 2015.

(b) Affected ADs

This AD replaces (AD) 2012–18–12, Amendment 39–17189 (77 FR 57003, September 17, 2012).

(c) Applicability

This AD applies to the Airbus airplanes identified in paragraphs (c)(1), (c)(2), and (c)(3) of this AD, certificated in any category, all manufacturer serial numbers.

(1) Model A318–111, –112, –121, and –122 airplanes.

(2) Model A319–111, –112, –113, –114, –115, –131, –132, and –133 airplanes.

(3) Model 320–211, –212, –214, –231, –232, and –233 airplanes.

(d) Subject

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

(e) Reason

This AD was prompted by a report of a torn out aspirator due to the aspirator interfering with the extrusion lip of the off-wing escape slide (OWS) enclosure during the initial stage of the deployment sequence. This AD was also prompted by reports that additional OWS part numbers have been affected which requires expanding the applicability to all Airbus Model A318, A319, and A320 series airplanes. We are issuing this AD to prevent off-wing exits on the left-hand (LH) and right-hand (RH) sides of the fuselage from becoming inoperative, which, during an emergency, could impair the safe evacuation of occupants, possibly resulting in personal injuries.

(f) Compliance

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

(g) Retained Modification

This paragraph restates the requirements of paragraph (g) of AD 2012–18–12, Amendment 39–17189 (77 FR 57003, September 17, 2012) with no changes. For airplanes equipped with OWS enclosures having part number (P/N) D31865–109, D31865–110, D31865–209, or D31865–210, except as provided by paragraph (i)(1) of this AD: Within 36 months after October 22, 2012, (the effective date of AD 2012–18–12), modify the OWS enclosures and install an OWS enclosure having P/N D31865–309, D31865–311, D31865–310, or D31865–312 on the LH side and RH side of the fuselage, in accordance with the Accomplishment Instructions of Airbus Service Bulletin A320–25–1649, dated February 16, 2010.

(h) New Modification of Affected OWS Enclosures and Aspirators

For airplanes equipped with an OWS enclosure having P/N D31865–101, D31865–102, D31865–103, D31865–104, D31865–105, D31865–106, D31865–107, or D31865–108, except as provided by paragraph (i)(2) of this AD: Within 36 months after the effective date of this AD, do the actions specified in paragraphs (h)(1) and (h)(2) of this AD.

(1) Modify the OWS enclosures and their aspirators in accordance with the Accomplishment Instructions of Airbus Service Bulletin A320–25–1156, Revision 03, dated December 5, 2001.

(2) Install off-wing escape slides having P/N D31865–109, D31865–110, D31865–209, or D31865–210 on the LH side and RH side of the fuselage, in accordance with the Accomplishment Instructions of Airbus Service Bulletin A320–25–1265, Revision 01, dated December 5, 2001; and accomplish the modification required by paragraph (g) of this AD.

(i) Exceptions to the Requirements of Paragraphs (g) and (h) of This AD

(1) Airplanes having Airbus modification 30088 embodied in production using an OWS enclosure having P/N D31865–111 or D31865–112 are not affected by the requirements of paragraph (g) of this AD, unless a replacement OWS enclosure, having a part number listed in paragraphs (k)(9) through (k)(12) of this AD, has been installed on that airplane since first flight.

(2) Airplanes on which Airbus modifications 24850, 25844, and 27275 have been embodied in production, or on which modifications of the LH and RH OWS enclosures and their aspirators have been accomplished using Airbus Service Bulletin A320–25–1156, Revision 01, dated February 2, 1999, or Revision 2, dated October 26, 1999, and Airbus Service Bulletin A320–25–1265, dated June 6, 2001, are compliant with the modification requirement of paragraph (h) of this AD.

(j) Optional Method of Compliance for Paragraph (g) of This AD

Installing both LH and RH OWS that have been modified in accordance with the Accomplishment Instructions of Air Cruisers Service Bulletin A320 004–25–84, Revision 4, dated November 9, 2012, is an acceptable method of compliance with the modification required by paragraph (g) of this AD.

(k) Part Installation Prohibition

As of the effective date of this AD, do not install on any airplane an OWS enclosure having a part number listed in paragraphs (k)(1) through (k)(12) of this AD, except as required by paragraph (h)(2) of this AD for the OWS enclosures identified in paragraph (h) of this AD.

(1) D31865–101
(2) D31865–102
(3) D31865–103
(4) D31865–104
(5) D31865–105
(6) D31865–106
(7) D31865–107
(8) D31865–108
(9) D31865–109
(10) D31865–110
(11) D31865–209
(12) D31865–210

(l) Credit for Previous Actions

(1) This paragraph provides credit for the actions specified in paragraph (h)(1) of this AD, if those actions were performed before the effective date of this AD using the service information identified in paragraph (l)(1)(i) or (l)(1)(ii) of this AD, which is not incorporated by reference.

(i) Airbus Service Bulletin A320–25–1156, Revision 01, dated February 2, 1999.

(ii) Airbus Service Bulletin A320–25–1156, Revision 02, dated October 26, 1999.

(2) This paragraph provides credit for the actions specified in paragraph (h)(2) of this AD, if those actions were performed before the effective date of this AD using Airbus Service Bulletin A320–25–1265, dated June 6, 2001, which is not incorporated by reference.

(3) This paragraph provides credit for the actions specified in paragraph (j) of this AD, if those actions were performed before the effective date of this AD using the service information identified in paragraph (l)(3)(i), (l)(3)(ii), (l)(3)(iii), or (l)(3)(iv) of this AD, which is not incorporated by reference.

(i) Air Cruisers Service Bulletin A320 004–25–84, dated February 5, 2010.

(ii) Air Cruisers Service Bulletin A320 004–25–84, Revision 1, dated April 9, 2010.

(iii) Air Cruisers Service Bulletin A320 004–25–84, Revision 2, dated February 11, 2011.

(iv) Air Cruisers Service Bulletin A320 004–25–84, Revision 3, dated October 28, 2011.

(m) 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: Sanjay Ralhan, Aerospace Engineer, International Branch, ANM–116, Transport Airplane Directorate, FAA, 1601 Lind Avenue SW., Renton, WA 98057–3356; telephone 425–227–1405; fax 425–227–1149 Information may be emailed to: *9-ANM-116-AMOC-REQUESTS@faa.gov.*

(i) 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.

(ii) AMOCs approved previously for AD 2012–18–12, Amendment 39–17189 (77 FR 57003, September 17, 2012), are approved as AMOCs for the corresponding provisions of paragraph (g) of this AD.

(2) *Contacting the Manufacturer:* As of the effective date of this AD, 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.

(n) Related Information

(1) Refer to Mandatory Continuing Airworthiness Information (MCAI) European Aviation Safety Agency (EASA) Airworthiness Directive 2014–0025R1, dated May 26, 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–2015–4202.

(2) For Airbus service information identified in this AD, contact Airbus, Airworthiness Office—EIAS, 1 Rond Point Maurice Bellonte, 31707 Blagnac Cedex, France; telephone +33 5 61 93 36 96; fax +33 5 61 93 44 51; email *account.airworth-eas@airbus.com*; Internet *http://www.airbus.com.* For Air Cruisers service information identified in this AD, contact Air Cruisers Company, Cage Code 70167, 1747 State Route 34, Wall Township, NJ 07727–3935; telephone 732–681–3527; fax 732–681–9163; Internet *http://www.zodiacaerospace.com/en/our-activities/aerosafety/zodiac-evacuation-systems.* 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 October 11, 2015.

Jeffrey E. Duven,

Manager, Transport Airplane Directorate, Aircraft Certification Service.

[FR Doc. 2015–26611 Filed 10–22–15; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF THE TREASURY

Internal Revenue Service

26 CFR Parts 1, 20, 25, 26, 31, and 301

[REG–148998–13]

RIN 1545–BM10

Definition of Terms Relating to Marital Status

AGENCY: Internal Revenue Service (IRS), Treasury.

ACTION: Notice of proposed rulemaking.

SUMMARY: This document contains proposed regulations that reflect the holdings of *Obergefell* v. *Hodges,* 576 U.S. __, 135 S. Ct. 2584 (2015), *Windsor* v. *United States,* 570 U.S. __, 133 S. Ct. 2675 (2013), and Revenue Ruling 2013–17 (2013–38 IRB 201), and that define terms in the Internal Revenue Code (Code) describing the marital status of taxpayers. The proposed regulations primarily affect married couples, employers, sponsors and administrators of employee benefit plans, and executors. This document invites comments from the public regarding these proposed regulations.

DATES: Written or electronic comments and requests for a public hearing must be received by December 7, 2015.

ADDRESSES: Send submissions to: CC:PA:LPD:PR (REG–148998–13), Room 5205, Internal Revenue Service, P.O. 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–148998–13), Courier's Desk, Internal Revenue Service, 1111 Constitution Avenue NW., Washington, DC; or sent electronically via the Federal eRulemaking Portal at *www.regulations.gov* (IRS REG–148998–13).

FOR FURTHER INFORMATION CONTACT: Concerning the proposed amendments to the regulations, Mark Shurtliff at (202) 317–3400; concerning submissions of comments and requests for a hearing, Regina Johnson at (202) 317–6901 (not toll-free numbers).

SUPPLEMENTARY INFORMATION:

Background and Explanation of Provisions

This document contains proposed amendments to the Income Tax Regulations (26 CFR part 1), the Estate Tax Regulations (26 CFR part 20), the Gift Tax Regulations (26 CFR part 25), the Generation-Skipping Transfer Tax Regulations (26 CFR part 26), the Employment Tax and Collection of Income Tax at Source Regulations (26 CFR part 31), and the Regulations on Procedure and Administration (26 CFR part 301).

Amendments to Regulations Incorporating Holdings of Windsor, Obergefell, and Revenue Ruling 2013–17

On June 26, 2013, the Supreme Court in *United States* v. *Windsor,* 570 U.S. __, 133 S. Ct. 2675 (2013), held that Section 3 of the Defense of Marriage Act, which generally prohibited the federal government from recognizing the marriages of same-sex couples, is unconstitutional because it violates the principles of equal protection and due process. Revenue Ruling 2013–17 provides guidance on the *Windsor* decision's effect on the IRS's interpretation of Code sections that refer to taxpayers' marital status. *Cf.* Notice 2014–19 (2014–47 IRB 979), amplified by Notice 2014–37 (2014–24 IRB 1100) (regarding the application of the *Windsor* decision to qualified retirement plans); Notice 2014–1 (2014–02 IRB 270) (regarding elections and reimbursements for same-sex spouses under cafeteria plans, flexible spending arrangements, and health savings accounts following the Windsor decision); Notice 2013–61 (2013–44 IRB 432) (regarding the application of the *Windsor* decision and Rev. Rul. 2013–17 to employment taxes and special administrative procedures for employers to make adjustments or claims for refund or credit); and Revenue Procedure 2014–18 (2014–7 IRB 513) (regarding extensions of time for estates to make a portability election). On June 26, 2015, the Supreme Court in *Obergefell* v. *Hodges,* 576 U.S. __ (2015), held that state laws are ''invalid to the extent they exclude same-sex couples from civil marriage on the same terms and conditions as opposite-sex couples'' and ''that there is no lawful basis for a State to refuse to recognize a lawful same-sex marriage performed in another State on the ground of its same-sex character.'' *Obergefell,* 576 U.S. at 23, 28.

In light of the holdings of *Windsor* and *Obergefell,* the Treasury Department and the IRS have determined that, for federal tax purposes, marriages of couples of the same-sex should be treated the same as marriages of couples of the opposite-sex and that, for reasons set forth in Revenue Ruling 2013–17, terms indicating sex, such as ''husband,'' ''wife,'' and ''husband and wife,'' should be interpreted in a neutral way to include same-sex spouses as well as opposite-sex spouses. Accordingly, these proposed regulations amend the current regulations under section 7701 of the Internal Revenue Code (Code) to provide that, for federal tax purposes, the terms ''spouse,'' ''husband,'' and ''wife'' mean an individual lawfully married to another individual, and the term ''husband and wife'' means two individuals lawfully married to each other. These definitions apply regardless of sex.

In addition, these proposed regulations provide that a marriage of two individuals will be recognized for federal tax purposes if that marriage would be recognized by any state, possession, or territory of the United States. Under this rule, whether a marriage conducted in a foreign jurisdiction will be recognized for federal tax purposes depends on whether that marriage would be recognized in at least one state, possession, or territory of the United States. This comports with the general principles of comity where countries recognize actions taken in foreign jurisdictions, but only to the extent those actions do not violate their own laws. See *Hilton* v. *Guyot,* 159 U.S. 113, 167 (1895) (''A judgment affecting the status of persons, such as a decree confirming or dissolving a marriage, is recognized as valid in every country, unless contrary to the policy of its own law.'').

Although these proposed regulations define terms relating to marital status for federal tax purposes, the IRS may provide additional guidance as needed. For example, the IRS has already issued more particular guidance for employers regarding the application of Revenue Ruling 2013–17 to qualified retirement plans, and that guidance remains in effect. See Notice 2014–19 (2014–47 IRB 979).

Registered Domestic Partnerships, Civil Unions, or Other Similar Relationships Not Denominated as Marriage

For federal tax purposes, the term ''marriage'' does not include registered domestic partnerships, civil unions, or other similar relationships recognized under state law that are not denominated as a marriage under that state's law, and the terms ''spouse,'' ''husband and wife,'' ''husband,'' and ''wife'' do not include individuals who have entered into such a relationship.

Except when prohibited by statute, the IRS has traditionally looked to the states to define marital status. See *Loughran* v. *Loughran,* 292 U.S. 216, 223 (1934) (''Marriages not polygamous or incestuous, or otherwise declared void by statute, will, if valid by the law of the state where entered into, be recognized as valid in every other jurisdiction.''); see also Revenue Ruling 58–66 (1958–1 CB 60) (if a state recognizes a common-law marriage as a valid marriage, the IRS will also recognize the couple as married for purposes of federal income tax filing status and personal exemptions). States have carefully considered the types of relationships that they choose to recognize as a marriage and the types that they choose to recognize as something other than a marriage. Although some states extend all of the rights and responsibilities of marriage under state law to couples in registered domestic partnerships, civil unions, or other similar relationships, those states have intentionally chosen not to denominate those relationships as marriages. Similar rules exist in some foreign jurisdictions.

Some couples have chosen to enter into a civil union or registered domestic partnership even when they could have married, and some couples who are in a civil union or registered domestic partnership have chosen not to convert those relationships into a marriage even when they have had the opportunity to do so. In many cases, this choice was deliberate, and couples who enter into civil unions or registered domestic partnerships may have done so with the expectation that their relationship will not be treated as a marriage for purposes of federal law. For some of these couples, there are benefits to being in a relationship that provides some, but not all, of the protections and responsibilities of marriage. For example, some individuals who were previously married and receive Social Security benefits as a result of their previous marriage may choose to enter into a civil union or registered domestic partnership (instead of a marriage) so that they do not lose their Social Security benefits. More generally, the rates at which some couples' income is taxed may increase if they are considered married and thus required to file a married-filing-separately or married-filing-jointly federal income tax return. Treating couples in civil unions and registered domestic partnerships the same as married couples who are in a relationship denominated as marriage under state law could undermine the expectations certain couples have regarding the scope of their relationship. Further, no provision of the Code indicates that Congress intended to recognize as marriages civil unions, registered domestic partnerships, or similar relationships. Accordingly, the IRS will not treat civil unions, registered domestic partnerships, or other similar relationships as marriages for federal tax purposes.

Effect on Other Documents

These proposed regulations would, as of the date they are published as final regulations in the **Federal Register**, obsolete Revenue Ruling 2013–17. Taxpayers may continue to rely on guidance related to the application of Revenue Ruling 2013–17 to employee benefit plans and the benefits provided under such plans, including Notice 2013–61, Notice 2014–37, Notice 2014–19, and Notice 2014–1.

Proposed Effective/Applicability Date

The regulations, as proposed, would be applicable as of the date of publication of a Treasury decision adopting these rules as final regulations in the **Federal Register**.

Statement of Availability for IRS Documents

For copies of recently issued Revenue Procedures, Revenue Rulings, Notices, and other guidance published in the Internal Revenue Bulletin, please visit the IRS Web site at *http://www.irs.gov.*

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. In addition, 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. Accordingly, a regulatory flexibility analysis is not required under the Regulatory Flexibility Act (5 U.S.C. chapter 6). Pursuant to section 7805(f) of the Code, this notice of proposed rulemaking will be submitted to the Chief Counsel for Advocacy of the Small Business Administration for comment on its impact on small businesses.

Comments and Requests for 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. Treasury 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 will be scheduled if requested in writing by any person who timely submits written comments. If a public hearing is scheduled, notice of the date, time, and place for the public hearing will be published in the **Federal Register**.

Drafting Information

The principal author of these proposed regulations is Mark Shurtliff of the Office of the Associate Chief Counsel, Procedure and Administration.

List of Subjects

26 CFR Part 1

Income taxes, Reporting and recordkeeping requirements.

26 CFR Part 20

Estate taxes, Reporting and recordkeeping requirements.

26 CFR Part 25

Gift taxes, Reporting and recordkeeping requirements.

26 CFR Part 26

Estate, Reporting and recordkeeping requirements.

26 CFR Part 31

Employment taxes, Income taxes, Penalties, Pensions, Reporting and recordkeeping requirements, Social Security, Unemployment compensation.

26 CFR Part 301

Employment taxes, Estate taxes, Excise taxes, Gift taxes, Income taxes, Penalties, Reporting and recordkeeping requirements.

Proposed Amendments to the Regulations

Accordingly, 26 CFR parts 1, 20, 25, 26, 31, and 301 are 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 * * *

■ **Par 2.** Section 1.7701–1 is added to read as follows:

§ 1.7701–1 Definitions; spouse, husband and wife, husband, wife, marriage.

(a) *In general.* For the definition of the terms spouse, husband and wife, husband, wife, and marriage, see § 301.7701–18 of this chapter.

(b) *Effective/applicability date.* The rules of this section apply to taxable years ending on or after the date of publication of the Treasury decision adopting these rules as final regulation in the **Federal Register**.

PART 20—ESTATE TAX; ESTATES OF DECEDENTS DYING AFTER AUGUST 16, 1954

■ **Par. 3.** The authority citation for part 20 continues to read in part as follows:

Authority: 26 U.S.C. 7805 * * *

■ **Par. 4.** Section 20.7701–2 is added to read as follows:

§ 20.7701–2 Definitions; spouse, husband and wife, husband, wife, marriage.

(a) *In general.* For the definition of the terms spouse, husband and wife, husband, wife, and marriage, see § 301.7701–18 of this chapter.

(b) *Effective/applicability date.* The rules of this section apply to taxable years ending on or after the date of publication of the Treasury decision adopting these rules as final regulation in the **Federal Register**.

PART 25—GIFT TAX; GIFTS MADE AFTER DECEMBER 31, 1954

■ **Par. 5.** The authority citation for part 25 continues to read in part as follows:

Authority: 26 U.S.C. 7805 * * *

■ **Par. 6.** Section 25.7701–2 is added to read as follows:

§ 25.7701–2 Definitions; spouse, husband and wife, husband, wife, marriage.

(a) *In general.* For the definition of the terms spouse, husband and wife, husband, wife, and marriage, see § 301.7701–18 of this chapter.

(b) *Effective/applicability date.* The rules of this section apply to taxable years ending on or after the date of publication of the Treasury decision adopting these rules as final regulation in the **Federal Register**.

PART 26—GENERATION-SKIPPING TRANSFER TAX REGULATIONS UNDER THE TAX REFORM ACT OF 1986

■ **Par. 7.** The authority citation for part 26 continues to read in part as follows:

Authority: 26 U.S.C. 7805 * * *

■ **Par. 8.** Section 26.7701–2 is added to read as follows:

§ 26.7701–2 Definitions; spouse, husband and wife, husband, wife, marriage.

(a) *In general.* For the definition of the terms spouse, husband and wife, husband, wife, and marriage, see § 301.7701–18 of this chapter.

(b) *Effective/applicability date.* The rules of this section apply to taxable years ending on or after the date of publication of the Treasury decision adopting these rules as final regulation in the **Federal Register**.

PART 31—EMPLOYMENT TAXES AND COLLECTION OF INCOME TAX AT THE SOURCE

■ **Par. 9.** The authority citation for part 31 continues to read in part as follows:

Authority: 26 U.S.C. 7805 * * *

■ **Par. 10.** Section 31.7701–2 is added to read as follows:

§ 31.7701–2 Definitions; spouse, husband and wife, husband, wife, marriage.

(a) *In general.* For the definition of the terms spouse, husband and wife, husband, wife, and marriage, see § 301.7701–18 of this chapter.

(b) *Effective/applicability date.* The rules of this section apply to taxable years ending on or after the date of publication of the Treasury decision adopting these rules as final regulation in the **Federal Register**.

PART 301—PROCEDURE AND ADMINISTRATION

■ **Par. 11.** The authority citation for part 301 continues to read in part as follows:

Authority: 26 U.S.C. 7805 * * *

■ **Par. 12.** Section 301.7701–18 is added to read as follows:

§ 301.7701–18 Definitions; spouse, husband and wife, husband, wife, marriage.

(a) *In general.* For federal tax purposes, the terms *spouse, husband,* and *wife* mean an individual lawfully married to another individual. The term *husband and wife* means two individuals lawfully married to each other.

(b) *Persons who are married for federal tax purposes.* A marriage of two individuals is recognized for federal tax purposes if the marriage would be recognized by any state, possession, or territory of the United States.

(c) *Persons who are not married for federal tax purposes.* The terms *spouse, husband,* and *wife* do not include individuals who have entered into a registered domestic partnership, civil union, or other similar relationship not denominated as a marriage under the law of a state, possession, or territory of the United States. The term *husband*

and wife does not include couples who have entered into such a relationship, and the term *marriage* does not include such relationships.

(d) *Effective/applicability date.* The rules of this section apply to taxable years ending on or after the date of publication of the Treasury decision adopting these rules as final regulation in the **Federal Register**.

John M. Dalrymple,

Deputy Commissioner for Services and Enforcement.

[FR Doc. 2015–26890 Filed 10–21–15; 4:15 pm]

BILLING CODE 4830–01–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 52

[EPA–R10–OAR–2014–0562: FRL–9935–47–Region 10]

Approval and Promulgation of Implementation Plans; Oregon: Lane Regional Air Protection Agency Open Burning Rules and Oregon Department of Environmental Quality Enforcement Procedures

AGENCY: Environmental Protection Agency.

ACTION: Proposed rule.

SUMMARY: The Environmental Protection Agency (EPA) is proposing to approve into Oregon's State Implementation Plan (SIP) a submittal from the Oregon Department of Environmental Quality (ODEQ) dated July 7, 2014, containing revisions to the Lane Regional Air Protection Agency's (LRAPA) open burning rules adopted on March 14, 2008. The revised LRAPA open burning rules make clarifications and provide for additional controls of open burning activities in Lane County, would reduce particulate emissions in Lane County, and would strengthen Oregon's SIP. The EPA is also proposing to approve a submittal from the ODEQ dated June 30, 2014, to update Oregon Administrative Rules (OAR) that relate to procedures in contested cases (appeals), enforcement procedures, and civil penalties. The EPA is proposing to approve most of the submitted provisions because the revisions clarify and strengthen the SIP and are consistent with the Clean Air Act (CAA). The EPA is not proposing to approve certain provisions of the submitted rules that do not relate to the requirements for SIPs under section 110 of the CAA. Finally, the EPA is proposing to correct the SIP pursuant to the authority of section 110(k)(6) of the CAA to remove certain provisions previously approved by the EPA that do not relate to the requirements for SIPs under section 110 of the CAA.

DATES: Comments must be received on or before November 23, 2015.

ADDRESSES: Submit your comments, identified by Docket ID No. EPA–R10–OAR–2014–0562, by any of the following methods:

- *Federal eRulemaking Portal http://www.regulations.gov:* Follow the on-line instructions for submitting comments.
- *Email: R10-Public_Comments@epa.gov*
- *Mail:* Mr. Keith Rose, U.S. EPA Region 10, Office of Air, Waste and Toxics, AWT–150, 1200 Sixth Avenue, Suite 900, Seattle, WA 98101
- *Hand Delivery/Courier:* U.S. EPA Region 10, 1200 Sixth Avenue, Suite 900, Seattle, WA 98101. Attention: Keith Rose, Office of Air, Waste and Toxics, AWT–150. Such deliveries are only accepted during normal hours of operation, and special arrangements should be made for deliveries of boxed information.

Please see the direct final rule which is located in the Rules section of this **Federal Register** for detailed instructions on how to submit comments.

FOR FURTHER INFORMATION CONTACT: Keith Rose at telephone number: (206) 553–1949, email address: *rose.keith@epa.gov,* or the above EPA, Region 10 address.

SUPPLEMENTARY INFORMATION: For further information, please see the direct final action, of the same title, which is located in the Rules section of this **Federal Register**. The EPA is simultaneously approving the State's SIP revision as a direct final rule without prior proposal because the EPA views this as a noncontroversial SIP revision and anticipates no adverse comments. A detailed rationale for the approval is set forth in the preamble to the direct final rule. If the EPA receives no adverse comments, the EPA will not take further action on this proposed rule.

If the EPA receives adverse comments, the EPA will withdraw the direct final rule and it will not take effect. The EPA will address all public comments in a subsequent final rule based on this proposed rule. The 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 we receive adverse comment on an amendment, paragraph, or section of this rule and if that provision may be severed from the remainder of the rule, the EPA may adopt as final those provisions of the rule that are not the subject of an adverse comment.

Dated: September 25, 2015.

Michelle L. Pirzadeh,

Acting Regional Administrator, Region 10.

[FR Doc. 2015–26145 Filed 10–22–15; 8:45 am]

BILLING CODE 6560–50–P

FEDERAL COMMUNICATIONS COMMISSION

47 CFR Parts 15 and 73

[GN Docket No. 12–268; Report No. 3028]

Petitions for Reconsideration of Action in Rulemaking Proceeding

AGENCY: Federal Communications Commission.

ACTION: Petition for reconsideration.

SUMMARY: Petitions for Reconsideration (Petitions) have been filed in the Commission's Rulemaking Proceeding by Ari Q. Fitzgerald, on behalf of GE Healthcare; Ronald J. Bruno on behalf of The VideoHouse, Inc.; Benjamin Perez on behalf of Abacus Television; Lawrence Rogow on behalf of WMTM, LLC; and Larry E. Morton on behalf of KMYA, LLC.

DATES: Oppositions to the Petitions must be filed on or before November 9, 2015. Replies to an opposition must be filed on or before November 17, 2015.

ADDRESSES: Federal Communications Commission, 445 12th Street SW., Washington, DC 20554.

FOR FURTHER INFORMATION CONTACT: Joyce Bernstein, Media Bureau, (202) 418–1647, email: *joyce.bernstein@fcc.gov*.

SUPPLEMENTARY INFORMATION: This is a summary of Commission's document, Report No. 3028, released September 21, 2015. The full text of the Petitions is available for viewing and copying in Room CY–B402, 445 12th Street SW., Washington, DC 20554 or may be accessed online via the Commission's Electronic Comment Filing System at *http://apps.fcc.gov/ecfs/.* The Commission will not send a copy of this *Notice* pursuant to the Congressional Review Act, 5 U.S.C. 801(a)(1)(A), because this notice does not have an impact on any rules of particular applicability.

Subject: Expanding the Economic and Innovation Opportunities of Spectrum Through Incentive Auctions, Second Order on Reconsideration, published at 80 FR 46824, August 6, 2015, in GN Docket No. 12–268, and published pursuant to 47 CFR 1.429(e). *See also* 47 CFR 1.4(b)(1).

Number of Petitions Filed: 2.

Federal Communications Commission.

Marlene H. Dortch,

Secretary.

[FR Doc. 2015–26872 Filed 10–22–15; 8:45 am]

BILLING CODE 6712–01–P

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

50 CFR Part 300

[Docket No. 150929898–5951–01]

RIN 0648–XE001; 0648–BF41

International Fisheries; Western and Central Pacific Fisheries for Highly Migratory Species; Treatment of U.S. Purse Seine Fishing With Respect to U.S. Territories

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

ACTION: Notice of decision on petition for rulemaking; advance notice of proposed rulemaking; request for comments.

SUMMARY: This document includes two distinct but related NMFS actions. First, NMFS announces that it has denied a petition for rulemaking from Tri Marine Management Company, LLC, related to purse seine fishing effort limits in the area of competence of the Commission for the Conservation and Management of Highly Migratory Fish Stocks in the Western and Central Pacific Ocean (Commission). Second, NMFS issues an advance notice of proposed rulemaking related to the treatment of U.S.-flagged purse seine vessels and their fishing activities in regulations implementing decisions of the Commission.

DATES: Comments on this advance notice of proposed rulemaking must be submitted in writing by November 23, 2015.

ADDRESSES: The notice of receipt of the petition for rulemaking, the petition, and the public comments on the petition are available via the Federal e-Rulemaking Portal at *www.regulations.gov* (search for Docket ID NOAA–NMFS–2015–0088).

NMFS is not requesting comments on the notice of decision on the petition.

You may submit comments on the advance notice of proposed rulemaking, identified by NOAA–NMFS–2015–0128, by either of the following methods:

• *Electronic submission:* Submit all electronic public comments via the Federal e-Rulemaking Portal.

1. Go to *www.regulations.gov/#!docketDetail;D=NOAA-NMFS-2015-0128,*
2. Click the ''Comment Now!'' icon, complete the required fields, and
3. Enter or attach your comments.

- OR -

• *Mail:* Submit written comments to Michael D. Tosatto, Regional Administrator, NMFS, Pacific Islands Regional Office (PIRO), 1845 Wasp Blvd., Building 176, Honolulu, HI 96818.

Instructions: Comments sent by any other method, to any other address or individual, or received after the end of the comment period, might 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 and address), 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).

FOR FURTHER INFORMATION CONTACT: Tom Graham, NMFS PIRO, 808–725–5032.

SUPPLEMENTARY INFORMATION:

Background on the Convention

The Convention on the Conservation and Management of Highly Migratory Fish Stocks in the Western and Central Pacific Ocean (Convention) focuses on the conservation and management of highly migratory species (HMS) and the management of fisheries for HMS. The objective of the Convention is to ensure, through effective management, the long-term conservation and sustainable use of HMS in the WCPO. To accomplish this objective, the Convention established the Commission, which includes Members, Cooperating Non-members, and Participating Territories. The United States of America is a Member. American Samoa, Guam, and the Commonwealth of the Northern Mariana Islands are Participating Territories.

As a Contracting Party to the Convention and a Member of the Commission, the United States implements domestically conservation and management measures adopted by the Commission and other decisions of the Commission. The Western and Central Pacific Fisheries Convention Implementation Act (16 U.S.C. 6901 *et seq.;* WCPFC Implementation Act), authorizes the Secretary of Commerce, in consultation with the Secretary of State and the Secretary of the Department in which the United States Coast Guard is operating (currently the Department of Homeland Security), to promulgate such regulations as may be necessary to carry out the obligations of the United States under the Convention, including the decisions of the Commission. The WCPFC Implementation Act further provides that the Secretary of Commerce shall ensure consistency, to the extent practicable, of fishery management programs administered under the WCPFC Implementation Act and the Magnuson-Stevens Fishery Conservation and Management Act (MSA; 16 U.S.C. 1801 *et seq.*), as well as other specific laws (see 16 U.S.C. 6905(b)). The Secretary of Commerce has delegated the authority to promulgate regulations under the WCPFC Implementation Act to NMFS. A map showing the boundaries of the area of application of the Convention (Convention Area), which comprises the majority of the WCPO, can be found on the WCPFC Web site at: *www.wcpfc.int/doc/convention-area-map.*

Background on Purse Seine Fishing Effort Limits in the Convention Area

Since 2009, NMFS regulations have established limits on fishing effort by U.S. purse seine fishing vessels in the area of application of the Convention (Convention Area), including in the area known as the Effort Limit Area for Purse Seine, or ELAPS, which is comprised of all areas of high seas and the U.S. exclusive economic zone (EEZ) between the latitudes of 20° N. and 20° S. in the Convention Area. These regulations are promulgated under authority of the WCPFC Implementation Act and have been codified at 50 CFR 300.223(a).

NMFS has established the purse seine fishing effort limits in the ELAPS to implement a series of Commission decisions for tropical tuna stocks in the Convention Area.

NMFS established a purse seine fishing effort limit in the ELAPS for 2015 in an interim rule published May 21, 2015 (80 FR 29220). NMFS issued a final rule, responding to comments on the interim rule and making final the interim rule, on August 25, 2015 (80 FR 51476). The limit is 1,828 fishing days.

On June 8, 2015, NMFS issued a notice announcing that the U.S. purse seine fishery in the ELAPS would close as a result of reaching the limit of 1,828 fishing days (80 FR 32313). The closure took effect June 15, 2015, and will remain in effect through December 31, 2015. The closure applies to all U.S. purse seine fishing vessels. During the closure, fishing vessels of the United

States equipped with purse seine gear may not be used to fish in the ELAPS.

Petition for Rulemaking

Under the Administrative Procedure Act, interested persons may petition Federal agencies for the issuance, amendment, or repeal of a rule.

As described further below, NMFS received such a petition from Tri Marine Management Company, LLC (Tri Marine). On July 17, 2015, NMFS issued a notice of receipt of the petition and a request for comments on the petition (80 FR 42464). The comment period ended August 17, 2015.

The Petition

In a petition dated May 12, 2015, Tri Marine requested that NMFS take two actions. First, Tri Marine requested that ''NOAA undertake an emergency rulemaking with respect to the 2015 ELAPS limits for fishing days on the high seas.'' Second, Tri Marine requested that ''NOAA issue a rule exempting from that high seas limit any US flag purse seine vessel which, pursuant to contract or declaration of intent, delivers or will deliver at least 50 percent of its catch to tuna processing facilities based in American Samoa.''

At the time of Tri Marine's initial request, NMFS was preparing to issue an interim rule establishing a limit on purse seine fishing effort in the ELAPS for 2015. As described above, NMFS established a limit in the ELAPS for 2015 in an interim rule published May 21, 2015. Accordingly, the first part of Tri Marine's request has been fully addressed and is not further discussed in this notice. NMFS acknowledged that it had received Tri Marine's petition for rulemaking in the May 21, 2015, interim rule, and stated that it would consider and respond to the petition separately.

With regard to the second part of Tri Marine's request, the petition explains that as a result of decisions by the Republic of Kiribati, U.S. purse seine vessels' access to their traditional fishing grounds in 2015 has been dramatically reduced, and that the high seas portion of the ELAPS can be expected to be closed to fishing as early as June. The petition further states that because of the limited fishing grounds now available to the American Samoa-based purse seine fleet and other factors, including an unusually low tuna price and the higher cost of access to fishing grounds in the region, the ability of American Samoa-based tuna vessels to operate profitably is in serious question, and the loss of a reliable supply of tuna from these vessels will jeopardize the ability of the canneries in American Samoa to compete in world markets. The petition states that under the Convention, American Samoa is afforded special treatment as a small island developing state or participating territory for purposes of applying conservation and management measures of the Commission, and therefore NMFS should develop rules that exempt from the ELAPS limit those vessels that deliver at least 50 percent of their catch to the canneries in American Samoa.

The petition includes further information on the basis of the request, including information related to the recommendations of the Governor of American Samoa's Fisheries Task Force, and an ''issue brief'' with statements about the nature of the issue and how the requested rule(s) would address it.

In a second letter to NMFS dated May 26, 2015, which supplements the May 12, 2015, petition, Tri Marine acknowledged the interim rule published May 21, 2015, and amended its request to include the U.S. EEZ. Tri Marine requested that ''NOAA undertake an emergency rulemaking with respect to the 2015 ELAPS limits for fishing days (both) on the high seas and in the US EEZ,'' and further requested that ''NOAA issue a rule exempting from the ELAPS limits any US flag purse seine vessel which, pursuant to contract or declaration of intent, delivers or will deliver at least 50 percent of its catch to tuna processing facilities based in American Samoa.''

Public Comments on the Petition

NMFS received comments on the petition from about 100 parties, including individuals employed in fish processing facilities in American Samoa and their families and friends; owners, operators and crew members of U.S. purse seine vessels; owners and operators of fish processing facilities in American Samoa; other businesses doing business in American Samoa; non-governmental organizations; and government officials of American Samoa and the United States. Most comments were in favor of the petition. Those in favor cited what they believed are adverse economic impacts of the 2015 ELAPS limit on purse seine fishing businesses, on fish processing facilities and other businesses in American Samoa, on employment in those businesses, and on the American Samoa economy in general. The comments in opposition to the petition argued that the requested action would unfairly favor certain businesses in the U.S. purse seine fishery over others and would be inconsistent with the Convention and the decisions of the Commission.

Decision on the Petition

After considering the petition and the public comments on the petition, NMFS finds that it is not appropriate to grant the petitioner's request to issue a rule exempting from the 2015 ELAPS limit any U.S.-flagged purse seine vessel which, pursuant to contract or declaration of intent, delivers or will deliver at least 50 percent of its catch to tuna processing facilities based in American Samoa. As described in the regulatory impact review prepared for the rule to establish the 2015 ELAPS limit, NMFS found that the limit is expected to have substantial adverse economic impacts on U.S. purse seine fishing businesses in the WCPO, and also that adverse impacts in terms of income and employment could occur in business sectors with backward and forward linkages to the producers. These sectors could include businesses that supply the purse seine fishing vessels, and the fish processing facilities in American Samoa. However, to sufficiently assess whether such impacts, or other circumstances, warrant the regulatory action requested by the petition would require additional information that is not readily available to NMFS, as well as sufficient time to examine such information. In particular, NMFS does not have information that demonstrates that the 2015 ELAPS limit will adversely impact American Samoa's fish processing facilities and its economy in the manner alleged by the petitioner. The petitioner argues that lacking the requested regulatory action, the ability of the American Samoa-based purse seine fleet to operate profitably would be in serious question, and the loss of a reliable supply of tuna from those vessels would jeopardize the ability of the canneries in American Samoa to compete in world markets with lower-cost competitors, and further, that tuna landings and processing are essential to the overall economic health of American Samoa.

NMFS has received some relevant information in the public comments on the petition, and NMFS intends to collect additional economic and other information. However, NMFS does not yet have sufficient information to determine whether the 2015 ELAPS limit is likely to jeopardize the ability of the American Samoa canneries to compete in world markets, or to determine how the loss of such competitiveness would affect American Samoa's overall economy. Moreover, if the 2015 ELAPS limit is found to impact American Samoa's fish processing facilities and its economy in the manner alleged in the petition, NMFS would need to determine whether the requested action is appropriate to address the problem, and further, whether it can be implemented consistent with U.S. obligations under the Convention and other applicable laws. NMFS does not expect that collecting and analyzing the necessary information, determining the appropriate course of action, if any, and completing such action could be accomplished before the end of 2015. For this reason, NMFS denies the second part of Tri Marine's petition for rulemaking.

Although NMFS has denied the petition, NMFS acknowledges that some of the issues raised in the petition warrant further examination. As described in the following section, NMFS intends to more fully examine the problems raised by the petitioner and by commenters on the petition. If the findings of that examination confirm a problem that—given U.S. obligations under the Convention and other applicable laws—warrants corrective action, NMFS would consider further rulemaking. At this time, however, NMFS cannot predict the timing or provisions of any future proposed or final rule.

Advance Notice of Proposed Rulemaking

Under the WCPFC Implementation Act, NMFS exercises broad discretion when determining how it implements Commission decisions, such as purse seine fishing restrictions. NMFS intends to examine the potential impacts of the domestic implementation of Commission decisions for purse seine fisheries on the economies of the U.S. Participating Territories, and examine the connectivity between the activities of U.S.-flagged purse seine fishing vessels and the economies of the territories. Based on those findings, NMFS will consider proposing regulations that mitigate adverse economic impacts of purse seine fishing restrictions on the U.S. Participating Territories, to the extent consistent with U.S. obligations under the Convention. Also, NMFS is considering proposing regulations that recognize that in the context of the Convention, one or more of the U.S. Participating Territories have their own purse seine fisheries that are distinct from the purse seine fishery of the United States. In that case, the purse seine fisheries of the U.S. Participating Territories might be subject to special provisions of the Convention and of Commission decisions, and NMFS would implement those provisions and decisions accordingly.

NMFS notes that the Tri Marine petition focused on the 2015 ELAPS limit. This advanced notice of proposed rulemaking is broader in scope, and could apply to other types of restrictions on purse seine fishing that are adopted by the Commission.

In summary, NMFS provides notice that it is considering proposing a rule that would establish rules and/or procedures to address the treatment of U.S.-flagged purse seine vessels and their fishing activities and how they relate to the U.S. Participating Territories in regulations issued by NMFS that implement decisions of the Commission.

NMFS solicits comments on this advance notice of proposed rulemaking. NMFS is particularly interested in receiving any information that would be helpful in assessing the impacts of Commission decisions for purse seine fisheries—as implemented domestically—on the economies of the U.S. Participating Territories, and any information that demonstrates connections between the U.S. Participating Territories and U.S.-flagged purse seine vessels and their fishing activities.

Classification

This advance notice of proposed rulemaking has been determined to be not significant for the purposes of Executive Order 12866.

Authority: 16 U.S.C. 6901 *et seq.*

Dated: October 19, 2015.

Eileen Sobeck,

Assistant Administrator for Fisheries, National Marine Fisheries Service.

[FR Doc. 2015–26968 Filed 10–20–15; 4:15 pm]

BILLING CODE 3510–22–P

Notices

Federal Register

Vol. 80, No. 205

Friday, October 23, 2015

DEPARTMENT OF AGRICULTURE

Agricultural Marketing Service

Submission for OMB Review; Comment Request

October 19, 2015.

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 November 23, 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: Application for Plant Variety Protection Certificate and Objective Description of Variety.

OMB Control Number: 0581–0055.

Summary of Collection: The Plant Variety Protection Act (PVPA) (December 24, 1970; 84 Stat. 1542, 7 U.S.C. 2321 *et seq.*) was established to encourage the development of novel varieties of sexually-reproduced plants and make them available to the public, providing intellectual property rights (IPR) protection to those who breed, develop, or discover such novel varieties, and thereby promote progress in agriculture in the public interest. The PVPA is a voluntary user funded program that grants intellectual property ownership rights to breeders of new and novel seed-and tuber-reproduced plant varieties. To obtain these rights the applicant must provide information that shows the variety is eligible for protection and that it is indeed new, distinct, uniform, and stable, as the law requires. Applicants are provided with applications to identify the information that is required to issue a certificate of protection.

Need and Use of the Information: Applicants must complete the ST–470, ''Application for Plant Variety Protection Certificate,'' and the ST–470 series of forms, ''Objective Description of Variety'' along with other forms. The Agricultural Marketing Service will use the information from the applicant to be evaluated by examiners to determine if the variety is eligible for protection under the PVPA. If this information were not collected there will be no basis for issuing certificate of protection, and no way for applicants to request protection.

Description of Respondents: Business or other for-profit; Federal Government.

Number of Respondents: 86.

Frequency of Responses: Reporting: On occasion; Other (varies).

Total Burden Hours: 2,907.

Charlene Parker,

Departmental Information Collection Clearance Officer.

[FR Doc. 2015–26891 Filed 10–22–15; 8:45 am]

BILLING CODE 3410–02–P

DEPARTMENT OF AGRICULTURE

Animal and Plant Health Inspection Service

[Docket No. APHIS–2015–0059]

Notice of Request for Revision to and Extension of Approval of an Information Collection; Importation of Citrus From Peru

AGENCY: Animal and Plant Health Inspection Service, USDA.

ACTION: Revision to and extension of approval of an information collection; comment request.

SUMMARY: In accordance with the Paperwork Reduction Act of 1995, this notice announces the Animal and Plant Health Inspection Service's intention to request a revision to and extension of approval of an information collection associated with importation of citrus from Peru.

DATES: We will consider all comments that we receive on or before December 22, 2015.

ADDRESSES: You may submit comments by either of the following methods:

- *Federal eRulemaking Portal:* Go to *http://www.regulations.gov/#!docketDetail;D=APHIS-2015-0059.*
- *Postal Mail/Commercial Delivery:* Send your comment to Docket No. APHIS–2015–0059, Regulatory Analysis and Development, PPD, APHIS, Station 3A–03.8, 4700 River Road Unit 118, Riverdale, MD 20737–1238.

Supporting documents and any comments we receive on this docket may be viewed at *http://www.regulations.gov/#!docketDetail;D=APHIS-2015-0059* or in our reading room, which is located in Room 1141 of the USDA South Building, 14th Street and Independence Avenue SW., Washington, DC. Normal reading room hours are 8 a.m. to 4:30 p.m., Monday through Friday, except holidays. To be sure someone is there to help you, please call (202) 799–7039 before coming.

FOR FURTHER INFORMATION CONTACT: For information on the importation of citrus from Peru, contact Mr. Juan (Tony) Román, Senior Regulatory Policy Specialist, RCC, IRM, PHP, PPQ, APHIS, 4700 River Road Unit 156, Riverdale, MD 20737; (301) 851–2242. For copies of more detailed information on the information collection, contact Ms. Kimberly Hardy, APHIS' Information Collection Coordinator, at (301) 851–2727.

SUPPLEMENTARY INFORMATION:

Title: Importation of Citrus From Peru.

OMB Control Number: 0579–0289.

Type of Request: Revision to and extension of approval of an information collection.

Abstract: The Plant Protection Act (PPA, 7 U.S.C. 7701 *et seq.*) authorizes the Secretary of Agriculture to restrict the importation, entry, or interstate movement of plants, plant products, and other articles to prevent the introduction of plant pests, including fruit flies, into the United States or their dissemination within the United States. Regulations authorized by the PPA concerning the importation of fruits and vegetables into the United States from certain parts of the world are contained in ''Subpart—Fruits and Vegetables'' (7 CFR 319.56–1 through 319.56–73).

In accordance with § 319.56–41, the citrus (grapefruit, limes, mandarins or tangerines, sweet oranges, and tangelos) from Peru is subject to certain conditions before entering the continental United States to prevent the introduction of plant pests into the United States. The regulations require the use of information collection activities, including inspections by national plant protection organization (NPPO) officials from Peru, grower registration and agreement, fruit fly trapping, monitoring, recordkeeping, and a phytosanitary certificate.

Since the last approval of this collection, we have adjusted the estimates of burden to more accurately reflect the number of grower registrations and agreements, the number of hours for recordkeeping, the number of respondents for phytosanitary certificates, and to account for activities that were omitted from the last collection (fruit fly management program, reinstatement of production sites, permits, and certification and recertification of cold treatment carriers).

We are asking the Office of Management and Budget (OMB) to approve our use of these information collection activities, as described, for an additional 3 years.

The purpose of this notice is to solicit comments from the public (as well as affected agencies) concerning our information collection. These comments will help us:

(1) Evaluate whether the collection of information is necessary for the proper performance of the functions of the Agency, including whether the information will have practical utility;

(2) Evaluate the accuracy of our estimate of the burden of the collection of information, including the validity of the methodology and assumptions used;

(3) Enhance the quality, utility, and clarity of the information to be collected; and

(4) Minimize the burden of the collection of information on those who are to respond, through use, as appropriate, of automated, electronic, mechanical, and other collection technologies; *e.g.,* permitting electronic submission of responses.

Estimate of burden: The public reporting burden for this collection of information is estimated to average 7.382 hours per response.

Respondents: NPPO of Peru and importers and growers of citrus fruit in Peru.

Estimated annual number of respondents: 31.

Estimated annual number of responses per respondent: 137.

Estimated annual number of responses: 4,245.

Estimated total annual burden on respondents: 31,339 hours. (Due to averaging, the total annual burden hours may not equal the product of the annual number of responses multiplied by the reporting burden per response.)

All responses to this notice will be summarized and included in the request for OMB approval. All comments will also become a matter of public record.

Done in Washington, DC, this 19th day of October 2015.

Kevin Shea,

Administrator, Animal and Plant Health Inspection Service.

[FR Doc. 2015–27099 Filed 10–22–15; 8:45 am]

BILLING CODE 3410–34–P

DEPARTMENT OF AGRICULTURE

Animal and Plant Health Inspection Service

[Docket No. APHIS–2015–0012]

Notice of Decision To Authorize the Importation of Fresh Pitahaya From Israel Into the Continental United States

AGENCY: Animal and Plant Health Inspection Service, USDA.

ACTION: Notice.

SUMMARY: We are advising the public of our decision to authorize the importation of fresh pitahaya fruit from Israel into the continental United States. Based on the findings of the pest risk analysis, which we made available to the public to review and comment through a previous notice, we have concluded that the application of one or more designated phytosanitary measures will be sufficient to mitigate the risks of introducing or disseminating plant pests or noxious weeds via the importation of fresh pitahaya fruit from Israel.

DATES: Effective October 23, 2015.

FOR FURTHER INFORMATION CONTACT: Mrs. Nicole Russo, Assistant Director, Imports, Regulations, and Manuals, PPQ, APHIS, 4700 River Road Unit 133, Riverdale, MD 20737–1231; (301) 851–2159.

SUPPLEMENTARY INFORMATION: Under the regulations in ''Subpart—Fruits and Vegetables'' (7 CFR 319.56–1 through 319.56–73, referred to below as the regulations), the Animal and Plant Health Inspection Service (APHIS) prohibits or restricts the importation of fruits and vegetables into the United States from certain parts of the world to prevent plant pests from being introduced into or disseminated within the United States.

Section 319.56–4 of the regulations contains a performance-based process for approving the importation of commodities that, based on the findings of a pest risk analysis, can be safely imported subject to one or more of the designated phytosanitary measures listed in paragraph (b) of that section. Under that process, APHIS publishes a notice in the **Federal Register** announcing the availability of the pest risk analysis that evaluates the risks associated with the importation of a particular fruit or vegetable. Following the close of the 60-day comment period, APHIS may begin issuing permits for importation of the fruit or vegetable subject to the identified designated measures if: (1) No comments were received on the pest risk analysis; (2) the comments on the pest risk analysis revealed that no changes to the pest risk analysis were necessary; or (3) changes to the pest risk analysis were made in response to public comments, but the changes did not affect the overall conclusions of the analysis and the Administrator's determination of risk.

In accordance with that process, we published a notice [1] in the **Federal Register** on April 28, 2015 (80 FR 23497, Docket No. APHIS–2015–0012), in which we announced the availability, for review and comment, of a pest risk assessment (PRA) that evaluated the risks associated with the importation into the continental United States of fresh pitahaya fruit from Israel and a risk management document (RMD) prepared to identify phytosanitary measures that could be applied to the commodities to mitigate the pest risk.

We solicited comments on the PRA and RMD for 60 days ending on June 29, 2015. We did not receive any comments by that date.

Therefore, in accordance with § 319.56–4(c)(2)(ii), we are announcing our decision to authorize the importation of fresh pitahaya fruit from Israel into the continental United States subject to the following phytosanitary measures:

- The pitahaya must be imported into the continental United States in commercial consignments only.
- Each consignment of pitahaya must be accompanied by a phytosanitary certificate issued by the national plant protection organization of Israel.
- Each consignment of pitahaya is subject to inspection upon arrival at the port of entry to the United States.

These conditions will be listed in the Fruits and Vegetables Import Requirements database (available at *http://www.aphis.usda.gov/favir*). In addition to these specific measures, fresh pitahaya fruit from Israel will be subject to the general requirements listed in § 319.56–3 that are applicable to the importation of all fruits and vegetables.

Authority: 7 U.S.C. 450, 7701–7772, and 7781–7786; 21 U.S.C. 136 and 136a; 7 CFR 2.22, 2.80, and 371.3.

Done in Washington, DC, this 19th day of October 2015.

Kevin Shea,

Administrator, Animal and Plant Health Inspection Service.

[FR Doc. 2015–27097 Filed 10–22–15; 8:45 am]

BILLING CODE 3410–34–P

[1] To view the notice, PRA, and RMD, go to *http://www.regulations.gov/#!docketDetail;D=APHIS-2015-0012.*

DEPARTMENT OF AGRICULTURE

Animal and Plant Health Inspection Service

[Docket No. APHIS–2014–0042]

Notice of Determination of the Classical Swine Fever, Foot-and-Mouth Disease, Rinderpest, and Swine Vesicular Disease Status of Croatia

AGENCY: Animal and Plant Health Inspection Service, USDA.

ACTION: Notice.

SUMMARY: We are adding Croatia to the lists of regions that are considered free of foot-and-mouth disease, rinderpest, and swine vesicular disease, and to the list of regions considered free or low risk for classical swine fever. We are taking this action because we have determined that this region is free of foot-and-mouth disease, rinderpest, and swine vesicular disease, and is low risk for classical swine fever. This action establishes the disease status of Croatia with regard to foot-and-mouth disease, rinderpest, swine vesicular disease, and classical swine fever while continuing to protect the United States from an introduction of those diseases.

DATES: Effective November 23, 2015.

FOR FURTHER INFORMATION CONTACT: Mr. Donald Link, Import Risk Analyst, Regionalization Evaluation Services, National Import Export Services, Veterinary Services, APHIS, 920 Main Campus Drive, Suite 200, Raleigh, NC 27606; (919) 855–7731; *Donald.B.Link@aphis.usda.gov.*

SUPPLEMENTARY INFORMATION:

Background

The regulations in 9 CFR part 94 (referred to below as the regulations) govern the importation of certain animals and animal products into the United States to prevent the introduction of various animal diseases, including classical swine fever (CSF), foot-and-mouth disease (FMD), rinderpest, and swine vesicular disease (SVD). The regulations prohibit or restrict the importation of live ruminants and swine, and products from these animals, from regions where these diseases are considered to exist.

Within part 94, § 94.1 contains requirements governing the importation of ruminants and swine from regions where rinderpest or FMD exists and the importation of the meat of any ruminants or swine from regions where rinderpest or FMD exists to prevent the introduction of either disease into the United States. We consider rinderpest and FMD to exist in all regions except those listed in accordance with paragraph (a) of that section as free of rinderpest and FMD. Section 94.9 contains requirements governing the importation of pork and pork products from regions where CSF exists. Section 94.10 contains importation requirements for swine from regions where CSF is considered to exist and designates the Animal and Plant Health Inspection Service (APHIS)-defined European CSF region as a single region of low-risk for CSF. Section 94.31 contains requirements governing the importation of pork, pork products, and swine from the APHIS-defined European CSF region. We consider CSF to exist in all regions of the world except those listed in accordance with paragraph (a) of § 94.9 as free of the disease.

Section 94.11 of the regulations contains requirements governing the importation of meat of any ruminants or swine from regions that have been determined to be free of rinderpest and FMD, but that are subject to certain restrictions because of their proximity to or trading relationships with rinderpest- or FMD-affected regions. Such regions are listed in accordance with paragraph (a) of that section.

Section 94.12 of the regulations contains requirements governing the importation of pork or pork products from regions where SVD exists. We consider SVD to exist in all regions of the world except those listed in accordance with paragraph (a) of that section as free of SVD.

Section 94.13 contains importation requirements governing the importation of pork or pork products from regions that have been declared free of SVD as provided in § 94.12(a) but supplement their national pork supply by the importation of fresh (chilled or frozen) meat of animals from regions where SVD is considered to exist, or have a common border with such regions, or have trade practices that are less restrictive than are acceptable to the United States. Such regions are listed in accordance with paragraph (a) of § 94.13.

Section 94.14 states that no swine which are moved from or transit any region in which SVD is known to exist may be imported into the United States except wild swine imported in accordance with § 94.14(b).

The regulations in 9 CFR part 92, § 92.2, contain requirements for requesting the recognition of the animal health status of a region (as well as for the approval of the export of a particular type of animal or animal product to the United States from a foreign region). If, after review and evaluation of the information submitted in support of the request, APHIS believes the request can be safely granted, APHIS will make its evaluation available for public comment through a document published in the **Federal Register.**

In accordance with that process, on February 3, 2015, we published in the **Federal Register** (80 FR 5728–5729, Docket No. APHIS–2014–0042) a notice [1] announcing the availability for review and comment of our risk evaluation of the CSF, FMD, rinderpest, and SVD status of Croatia. Based on this evaluation, we determined that that the animal disease surveillance, prevention, and control measures implemented by Croatia are sufficient to minimize the likelihood of introducing CSF, FMD, rinderpest, and SVD into the United States via imports of species or products susceptible to these diseases.

In addition, we determined in our evaluation that Croatia is low risk for CSF and therefore eligible to be added to the APHIS-defined European CSF region. This region is subject to the conditions in § 94.31 for pork, pork products, and swine and § 98.38 for swine semen. We also determined that the provisions of § 94.11 for import conditions for meat or meat products from ruminants or swine from FMD-free regions, and § 94.13 for import conditions for pork or pork products from SVD-free regions, are applicable to Croatia.

With respect to rinderpest, the global distribution of the disease has diminished significantly in recent years as a result of the Food and Agriculture Organization Global Rinderpest Eradication Program. The last known cases of rinderpest worldwide occurred in the southern part of the ''Somali pastoral ecosystem'' consisting of southern Somalia, eastern Kenya, and southern Ethiopia. In May 2011, the World Organization for Animal Health (OIE) announced its recognition of global rinderpest freedom.

We solicited comments on the notice of availability for 60 days ending on April 6, 2015. We received two comments by that date, both from national pork industry associations. Both commenters raised specific concerns about disease risks regarding our proposed action to recognize Croatia as being free of FMD, rinderpest, and SVD, and low risk for CSF, as this action would allow for the importation into the United States of swine, pork, and pork products from Croatia subject to the regulations. The comments are discussed below.

Smuggling of Prohibited Articles

The commenters noted that international passenger traffic was identified in the APHIS evaluation as a key risk factor for the introduction of the disease hazards. The commenters stated that limited data exists to determine the quantity of prohibited products smuggled into Croatia and that APHIS obtained estimates of international passenger traffic from 2006 data that is no longer current. The commenters requested that we require Croatia to provide updated information on passenger traffic in order to determine if the risk evaluation needs to be modified.

We agree with the commenter that limited data exists regarding smuggling of prohibited products into Croatia. Such data is by its nature limited because the intent of smuggling is to avoid disclosure, documentation, or inspection. We also acknowledge the volume of international passenger traffic into Croatia and agree that the introduction of prohibited products into Croatia could play a role in the transmission of animal diseases. As the commenters requested, we have provided more recent data for passenger traffic into Croatia.

Data available from the World Bank indicates that 9,111,000, 9,927,000, and 10,369,000 international inbound tourists (overnight visitors) entered Croatia in 2010, 2011, and 2012, respectively.[2] Additional data published by the Organisation for Economic Cooperation and Development (OECD) [3] (see Table 1) indicates total inbound tourism and primary countries of origin for arriving passengers.

TABLE 1—INBOUND TOURISM: TOTAL ARRIVALS AND PRIMARY COUNTRIES OF ORIGIN, CROATIA, 2008–2012

	2008	2009	2010	2011	2012
Total Intl Arrivals (x1000)	8,665	8,694	9,111	9,927	10,369
Top Markets (x1000).					
Germany	1,405	1,463	1,525	1,661	1,853
Slovenia	985	963	1,017	1,100	1,054
Italy	1,009	1,058	1,018	1,150	1,051
Austria	692	776	810	892	946
Czech Republic	589	579	606	638	647

While the above data indicates that Croatia has seen an increase in the number of international arrivals over the period indicated, the data does not change our conclusions in the risk evaluation. The updated number of arrivals does not differ substantially from the 2006 number we used in the risk evaluation. Additionally, the primary countries of origin listed in Table 1 for arriving passengers are other European Union (EU) Member States that APHIS recognizes to be free of FMD and rinderpest and low risk for CSF. Germany, Slovenia, Austria, and the Czech Republic are also free of SVD, as are several regions of Italy. We determined in the Croatia risk evaluation and previous swine disease status assessments of the EU and individual Member States that the animal health rules governing trade and travel between Member States mitigate the risk of contagious animal disease transmission through international passenger traffic.

We conclude that the risk of virus introduction into Croatia via the pathway of intentionally smuggled or unintentionally carried prohibited products is effectively mitigated by implementing EU-level and Croatian national policies regarding commodities for personal consumption and by the interdiction efforts of Croatia's Border Veterinary Inspection and International

[1] To view the notice of availability, risk evaluation, environmental assessment, and comments we received, go to *http://www.regulations.gov/#!docketDetail;D=APHIS-2014-0042.*

[2] *http://data.worldbank.org/indicator/ST.INT.ARVL.* The data on inbound tourists refer to the number of arrivals, not to the number of people traveling. Thus a person who makes several trips to a country during a given period is counted each time as a new arrival.

[3] Organisation for Economic Co-operation and Development (2014), ''Croatia'', in OECD Tourism Trends and Policies 2014, OECD Publishing. (Data cited by OECD was sourced from Croatian Bureau of Statistics data on tourism: *http://www.dzs.hr/default_e.htm.*)

Trade (BVIITS) and Customs departments. As described in the risk analysis, BVIITS and Customs are the Croatian authorities responsible for the inspection and confiscation and disposal of prohibited animal products at Croatia's points of entry. Furthermore, in addition to border controls, we determined in our risk assessment that Croatia has systems in place for surveillance and early detection of CSF, FMD, SVD, and rinderpest should any of these diseases be introduced via incoming passenger traffic into Croatia or any other pathway.

Disease Detection and Surveillance

The commenters stated concerns over the ability of commercial swine operations in Croatia to conduct surveillance for and detect foreign animal diseases. As evidence, the commenters cited in the risk evaluation a reference to an interview we conducted with the operator of a company-owned swine fattening farm, in which the operator seemed more aware of potential production impacts than on the clinical signs that would accompany an outbreak of CSF or SVD. The commenters asked if APHIS is confident that the level of awareness of swine operations in Croatia is sufficient for early detection of trade-limiting foreign animal diseases of swine. They recommended that prior to announcing a decision on Croatia's disease status, we should require Croatia to provide us with verification that the industry has been provided with the training or educational materials necessary to assist in active disease surveillance.

We reply that APHIS is confident in the level of awareness for swine diseases in Croatia's commercial swine operations. This particular commercial fattening farm represents Croatia's high intensity, high biosecurity, vertically integrated production and marketing system. Given the advanced swine husbandry standards, premises monitoring by company veterinarians, swine disease training, awareness and sampling, APHIS considers it highly likely that a trade-limiting swine disease in Croatia would be quickly detected and contained. Additionally, we consider Croatia's commercial swine production system to be the most likely source of pork or pork products for export to the United States, and consider the risk of undetected CSF-, FMD-, or SVD-contaminated products being sourced from this production chain to be low.

Regarding this particular commercial farm and farm operator, despite the observation the commenters cited in the risk evaluation, the same farm operator seemed knowledgeable of farm operations, company procedures, and Croatian veterinary and legal requirements. As noted on page 43 of the risk evaluation, we also observed evidence of strong operational, biosecurity, and recordkeeping practices on that farm, as well as strong veterinary oversight. State veterinary authorities reported that the farm receives educational information distributed by Croatia's Ministry of Agriculture, Fisheries, and Rural Development (MAFRD) and that company officials have attended swine disease symposia organized by the MAFRD Veterinary Directorate, which is the central competent authority for animal health and veterinary services in Croatia. In addition, a company veterinarian visits the premises every 2 weeks on average or when called to provide veterinary care. We also observed that the authorized veterinarian for this farm visits regularly to issue health certificates and movement documents.

Overall, our Croatia risk evaluation determined that Croatia has an effective surveillance system in place for detection of swine diseases, including surveillance strategies for the commercial swine sector. We agree with the commenters that early disease detection is a core element of all trade-participating countries and we saw no evidence that Croatia was lacking in this regard.

Small Farms and Backyard Premises

The commenters noted that we considered the disease risk posed by the small, family-operated breeding farm we visited (and backyard premises in general) to be different from that of vertically integrated commercial swine production systems, particularly with respect to animal disease traceability, animal sampling, and biosecurity. The commenters recommended that, before making a decision on Croatia's disease status, we require Croatia to provide a plan for risk reduction for small farms and backyard premises that addresses improving pre-harvest traceability, disease and biosecurity awareness, and disease sampling strategies that aid in early detection of trade-limiting foreign animal diseases.

In reply, we do consider the disease risk posed by small family-operated breeding farms and backyard premises to differ from the risk associated with Croatia's vertically integrated commercial swine production systems. However, we also observed measures that mitigate the risks associated with the small family-operated breeding farm we visited, including satisfactory operational, husbandry, and biosecurity standards. The farm controlled and catalogued on- and off-farm movements of animals, people, and supplies, and satisfied animal disease traceability requirements. Additionally, this farm was included in Croatia's swine disease surveillance program, as are other small farms in Croatia.

Regarding risk reduction plans, we note that Croatia does have such a plan in place for CSF in the form of legislation that places additional restrictions on swine, pork, and pork products produced in or moving from the counties of Vukovar-Srijem, Sisak-Moslavina, Karlovac, and Brod-Posavina, which are considered higher risk for CSF due to past serological events for CSF in feral swine. The family-operated breeding farm visited by APHIS was in Karlovac County and thus subject to these additional restrictions. As noted in the risk evaluation,[4] the additional risk reduction measures include specific biosecurity requirements such as cleaning and disinfection of vehicles and equipment. Additional measures also require that domestic swine from premises situated in the higher-risk counties can be marketed within Croatia if they undergo clinical examination and sampling procedures prior to movement from the premises of origin. The swine must also test negative for CSF within the 7 days prior to movement, and no swine must have been introduced to the premises within 30 days prior to movement. Domestic swine from higher-risk counties must be accompanied by a health certificate that includes the number of swine, place of origin, date of clinical examination, and disease sampling and diagnostic test results.

The additional risk reduction measures stipulate that fresh meat, meat preparations, or meat products consisting of or containing meat of swine originating from premises in Karlovac, Vukovar-Srijem, and Sisak-Moslavina Counties may be marketed and sold outside of these counties only if no evidence of CSF has been recorded in the previous 12 months on the premises and the premises is located outside a protection or surveillance zone. The swine are required to have resided for at least 90 days on the premises, and no swine are permitted to have been introduced into the premises within the previous 30 days before dispatch to slaughter. Under the additional risk reduction measures, Croatia also requires each premises to be

[4] Section 4, "Active Disease Control Programs," page 19.

inspected by an authorized veterinarian, including appropriate clinical examination and sampling of animals, twice per year. If swine are moved directly to slaughter, the animals are required to be clinically examined and sampled by an authorized veterinarian, culminating in a signed health certificate. Finally, the additional restrictions prevent semen, ova, and embryos from swine from these higher-risk counties from being marketed outside of those counties.

Animal Movement Safeguards

The commenters stated concern about the movement of swine within Croatia, noting that swine can be kept in livestock markets for no more than 12 hours and must be returned to the premises if not sold in that time. The commenters noted that commingling of swine outside of a production system or premises of origin at a market presents an elevated risk of disease transmission. For this reason, the commenters asked APHIS to clarify what, if any, regulations apply to reporting that animal movement back to the premises of origin and if there are any quarantine or movement restrictions or disease monitoring placed on that animal. The commenters recommended that APHIS ensure that reporting takes place for animal movement back to the premises of origin, that there are quarantine or movement restrictions as necessary, and that official monitoring for disease be in place and verified by Croatia.

We agree with the commenters that commingling of potentially infected but undetected swine in markets could contribute to rapid transmission and spread of contagious swine diseases. We acknowledged on page 46 of our risk evaluation that backyard premises with a single pig are exempt from most of Croatia's premises and animal registration requirements and that this presents a gap in animal disease traceability. We also acknowledged that backyard premises may present a biosecurity gap as some may not always conduct animal disease sampling or collect, analyze, and respond to changes in production data.

However, we consider it unlikely that animals/products from small farms or backyard premises will enter the export chain, as the movement and marketing patterns of Croatia's small farms and family premises are local and domestic in scope. Additionally, we concluded from our risk evaluation that the risk of disease transmission in small farm and backyard premises is mitigated at the premises and market levels. Although these premises are exempt from entry in the Croatian Agricultural Agency's Farm Register database, they must report the purchase of any pig to the competent veterinary organization at the time of delivery. Moreover, as the pig is most likely fed and fattened for personal consumption, we consider it unlikely that the pig would be moved off of a single- or double-swine backyard premises. Any swine that do move from a small premises require a movement permit and corresponding health certificate, and would most likely enter the local livestock market and be subject to the regulations enforced there. Livestock market regulations include the requirement that each animal consignment arriving to the market must be accompanied by a veterinary health certificate, issued within 30 days prior to movement, indicating veterinary inspection was performed prior to animals leaving the premises, as well as a travel document indicating that the transport vehicle underwent cleaning and disinfection.

Finally, the risk associated with an infected animal arriving at an animal market and being sent back to the premises of origin is also mitigated by veterinary inspection and corresponding documentation prior to animals moving to the market, as well as by the requirement that transport vehicles be disinfected.

Disease risk is further mitigated by other control measures that can be implemented in the event that a contagious animal disease is suspected or confirmed. The measures we observed included disinfection wheelbaths for vehicles and footbaths for people, and requiring that employees don personal protective clothing prior to entering the sale and transfer part of the market. Animal disease awareness educational pamphlets and contingency plans were on display in the market office, and the market has participated in disease outbreak simulation exercises.

Overall, we determined that Croatia has a sufficient infrastructure in place for reporting movement of pigs, including livestock markets, and concluded that disease monitoring took place at all critical points of Croatia's movement and marketing channels.

Surveillance for African Swine Fever

The commenters noted that Croatia conducts active surveillance for CSF, SVD, and FMD. However, they asked if we could determine whether active or passive surveillance is conducted for African swine fever (ASF), and whether the veterinary authority in Croatia rules out ASF in swine that present for inspection with case-compatible lesions.

We do not currently consider Croatia affected with ASF and did not conduct an evaluation of Croatia's ASF status. Thus, as the commenters acknowledged, passive and active surveillance for ASF are not specifically related to the risk assessment, which was conducted specifically for CSF, FMD, SVD, and rinderpest. However, we did conclude that Croatia maintains effective CSF and FMD emergency response plans, so if a disease investigation was triggered by case-compatible lesions we consider it highly likely that ASF would be appropriately confirmed or ruled out by Croatian veterinary officials.

We acknowledge that ASF has been a concern in the EU and in areas adjacent to the EU. The EU has laid down prevention and control measures [5] to be applied where ASF is suspected or confirmed, either in agricultural establishments or in wild boars. As an EU Member State, Croatia is required to implement EU-mandated prevention and control measures for all swine diseases, including ASF. APHIS continues to monitor the ASF situation in the EU, and Croatia would be subject to any restrictive action that APHIS takes towards the EU or individual Member States to mitigate the risk of introduction of ASF.

CSF Testing Methods

The commenters stated that the methods of investigation and testing in Croatia for suspected cases of CSF included in the risk evaluation appear to be inconsistent with the laboratory methods conducted in the United States that ensure rapid detection of CSF from samples submitted from a farm. The commenters suggested that this inconsistency could result in a significant delay in confirming the presence of CSF on farms in Croatia with case-compatible lesions and recommended that the competent veterinary authority of Croatia be required to improve laboratory detection methods so they are equivalent to those used in the United States.

Under OIE guidelines, APHIS import risk analyses are required to assess whether the end result of a sanitary measure or standard, in this case CSF detection methodology and disease confirmation, is equivalent to the end result of the importing country's measure or standard. While Croatia's CSF investigation and testing procedures may diverge slightly from U.S. protocols, we concluded from information gathered during the site visit that Croatia's CSF diagnostic

[5] *http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=CELEX:02002L0060-20080903:EN:NOT.*

testing protocols are in accordance with international standards and their end result would be rapid detection of CSF. We determined that Croatia's laboratory system was capable of quickly and accurately receiving, processing, and completing diagnostic tests on samples received. We also determined that these labs were able to accurately diagnose CSF, FMD, and SVD, distinguish them from differential diagnoses, and quickly communicate test results to the Croatian Veterinary Directorate and back to the field. Finally, we determined that Croatia's epidemiological investigations will capably trigger an appropriate surveillance response that would result in timely and accurate diagnosis of CSF.

Contaminated Food Waste

The commenters questioned our determination that contaminated food waste from Croatia poses a low disease risk to swine in the United States, noting that the risk findings we cited to help support this determination were conducted in 1995 and 2001 and do not reflect current risks to the U.S. pork industry.

One risk the commenters cited was the increased interstate trade of swine from States that allow the regulated feeding of garbage. The commenters recommended that the 1995 assessment be repeated using more recent data.

To the commenter's point, if contaminated meat products were imported from Croatia and managed to make it into plate waste, U.S. garbage feeding regulations will mitigate that risk. In 1995, we conducted a pathway analysis to estimate the likelihood of exposing domestic swine to infected waste. With 95 percent confidence, we estimated that 0.023 percent or less of plate and manufacturing waste would be inadequately processed prior to feeding to swine. Based on this percentage, less than 1 part in 4,300 of imported beef fed to swine as plate or manufacturing waste is likely to be inadequately cooked. The findings of a 2001 APHIS survey, which showed a substantial reduction in waste-feeding operations, further indicated that the risk of FMD exposure via feeding of contaminated waste to swine was continuing to decline.

Treatment of food waste to be fed to swine is covered under the Swine Health Protection Act[6] (SHPA) regulations in 9 CFR part 166 and supported by APHIS' Veterinary Service (VS) Swine Health Program (SHP). Under the regulations, waste feeder operations must be licensed and regularly inspected by APHIS inspectors. In addition to other safeguards, the licensing process requires that producers adequately cook the waste fed to swine using methods designed to destroy foreign animal disease agents.

We acknowledge that waste feeding continues to be a potential pathway for transmission of swine diseases and that interstate trade patterns are subject to change. We maintain, however, that the 1995 and 2001 risk findings, combined with existing SHPA requirements, indicate to us a low likelihood of exposure of domestic swine to CSF, FMD, SVD, and rinderpest from food waste originating from Croatia.

Verification of Garbage Heating Requirements

The commenters noted that the SHPA requires licensed facilities to have quarterly or bi-yearly temperature checks of garbage-cooking equipment for a minimum of two and a maximum of four temperature checks each fiscal year. The commenters asked how many of the licensed garbage feeders actually were temperature checked twice in 2014 by a regulatory official. They indicated concerns with the records licensed facilities maintain to verify that they are meeting cooking time and temperature requirements on days they are not inspected, and recommended that we determine what records licensed facilities maintain in order to provide such verification to State and Federal animal health officials.

While we require that licensed U.S. garbage-feeding facilities observe all garbage heating requirements under the SHPA regulations, cooking temperature and treatment requirements are outside the scope of this risk evaluation. Regulations addressing these practices are contained in 9 CFR part 166 and include provisions for inspection of heating equipment and records. Garbage-feeding facilities suspected of violating the regulations for storing and heating garbage for feeding are subject to license suspension or revocation.

Unlicensed Garbage Feeders

The commenters presented data from APHIS–VS reports to the U.S. Animal Health Association's Transmissible Diseases of Swine Committee indicating that, from 2009 to 2013, the number of non-licensed garbage feeders found by State and Federal animal health authorities in searches for non-licensed feeders was 104, 142, 68, 125, and 160, respectively. The commenters asked if APHIS has any supporting information on estimates of the number of unlicensed garbage-feeding facilities. Citing the disease risk posed by unlicensed garbage-feeding operations, the commenters expressed concern with our level of confidence that foreign animal diseases can be detected promptly in unlicensed garbage-feeding operations and asked if our emphasis on finding non-licensed feeders increased or decreased over the past couple of years. Procedures for the handling, processing, and feeding of food waste to swine in the United States are subject to our swine health protection regulations in 9 CFR part 166. Compliance with the regulations has improved in recent years, thereby reducing the probability of survival of FMD virus in the food waste. Searches for non-licensed garbage feeding facilities are regularly conducted using several different techniques as part of the duties of APHIS animal health staff, as well as State animal health and other State agency staff. During fiscal year 2014, animal health and other inspectors conducted 28,774 searches for non-licensed garbage feeding facilities with 122 documented non-licensed facilities identified, which indicates that unlicensed activity is infrequent.

When unlicensed garbage feeding facilities are identified, the unauthorized activity is documented, and the facility is brought into compliance. Depending on the State, all swine on such premises may be quarantined and tested for foreign animal diseases. Information on the number of inspections conducted to detect unlicensed garbage feeding facilities, the number of unlicensed facilities identified, and resolution of cases resulting from such identification are captured at the State level and evaluated by APHIS on a regular basis. Given the regular monitoring of these facilities and their relatively small number, we stand by the conclusions we reached in our 1995 risk analysis cited above.

SHPA Budget

The commenters stated a concern that budget cuts to APHIS–VS and State animal health officials have negatively affected the ability to effectively carry out the regulatory activities supporting the SHPA. They also expressed concern that the reduction in such activities has reduced the number of inspection and searches for unlicensed garbage-feeding operations to a level that is lower than what was indicated in the 1995 risk analysis.

Budget cuts to APHIS have necessitated a reordering of priorities in relation to SHPA-related activities. We have deemphasized or passed on to State partners or other cooperators lower-yield activities, such as visiting

[6] 7 U.S.C. 3801.

restaurants to inquire about garbage-disposal methods, in favor of allowing inspectors to spend more time interacting with and educating swine producers and conducting inspections. The regular presence of APHIS inspectors in U.S. garbage feeding facilities provides opportunities to educate operators on disease signs and reporting requirements and to conduct direct observation of animals for signs of illness. APHIS believes, therefore, that the presence of animal products infected with FMD or other reportable conditions entering the United States would be detected more quickly in these types of premises than in other, unregulated premises.

Environmental Assessment

The commenters noted that the environmental assessment (EA) provided with this rulemaking was the May 2011 EA for the importation of swine and swine commodities from Slovakia. They also noted that APHIS provided a supporting document that was an amended finding of no significant impact (FONSI) from importation of swine and swine commodities from Croatia that uses the EA from Slovakia as the basis for the amended finding related to Croatia. The commenters requested that APHIS expand on how it is justifiable to use an EA prepared for other countries and apply it to Croatia.

APHIS has conducted animal health status evaluations for multiple EU Member States for swine diseases. Since 2006 we have recognized the CSF, FMD, SVD, and/or rinderpest status for EU Member States Latvia, Lithuania, Poland, the Czech Republic, Slovakia, Slovenia, Estonia, and Hungary, and for certain countries that have entered into agricultural equivalence agreements with the EU. In each case, we determined that measures are in place to mitigate the risk of CSF, SVD, FMD, and/or rinderpest introduction into the United States through importation of swine, swine commodities, ruminants, and ruminant commodities from countries or regions that we recognize as low risk for CSF and free of SVD, FMD, and rinderpest.

Given that the EU applies and ensures enforcement of the same disease mitigation requirements across all EU Member States, we recognized that the single-state evaluations we were conducting were redundant and thus unnecessary with respect to meeting the requirements of the National Environmental Protection Act (NEPA). After we consulted with Agency specialists on NEPA, we did an environmental impact analysis comparison of the 2011 Slovakia EA analysis in regards to the proposed action of this notice for the EU Member State Croatia and determined that the environmental analyses of the Slovakia EA were similar and sufficient to cover the proposed action for Croatia. The 2011 Slovakia EA stated that for any like/similar future regionalization actions proposed for EU Member States, APHIS would incorporate the Slovakia EA by reference in a new FONSI issued for a proposed new action for an EU Member State. That is what we have done for this proposed action for Croatia.

Additionally, we determined that future proposed actions of this nature pose negligible environmental impacts to each EU Member State or country that has entered into an agricultural equivalency agreement with the EU, provided that a disease assessment finds them to be free of or a low risk for relevant diseases. As Croatia is an EU Member State and because we have determined that Croatia is free of SVD, FMD, and rinderpest, and at low risk for CSF, we believe that the ''like/similar action'' environmental analyses approach as presented in the 2011 Slovakia EA/FONSI is appropriate to use for the proposed action for Croatia.

Based on the evaluation and the reasons given in this document in response to comments, we are recognizing Croatia as free of FMD, rinderpest, and SVD, and low risk for CSF. The lists of regions recognized as free or at low risk of these diseases can be found by visiting the APHIS Web site at *http://www.aphis.usda.gov/wps/portal/aphis/ourfocus/importexport* and following the link to ''Animal or Animal Product.'' Copies of the lists are also available via postal mail, fax, or email upon request to the Regionalization Evaluation Services, National Import Export Services, Veterinary Services, Animal and Plant Health Inspection Service, 4700 River Road Unit 39, Riverdale, Maryland 20737.

Authority: 7 U.S.C. 450, 7701–7772, 7781–7786, and 8301–8317; 21 U.S.C. 136 and 136a; 31 U.S.C. 9701; 7 CFR 2.22, 2.80, and 371.4.

Done in Washington, DC, this 19th day of October 2015.

Kevin Shea,

Administrator, Animal and Plant Health Inspection Service.

[FR Doc. 2015–27092 Filed 10–22–15; 8:45 am]

BILLING CODE 3410–34–P

DEPARTMENT OF COMMERCE

International Trade Administration

[A–570–928]

Uncovered Innerspring Units From the People's Republic of China: Affirmative Preliminary Determination of Circumvention of the Antidumping Duty Order

AGENCY: Enforcement and Compliance, International Trade Administration, Department of Commerce.

SUMMARY: The Department of Commerce (''the Department'') preliminarily determines that uncovered innerspring units (''innersprings units'') completed or assembled in Malaysia by Goldon Bedding Manufacturing Sdn. Bhd. (''Goldon'') using components from the People's Republic of China (''PRC''), and exported to the United States, are circumventing the antidumping duty order on innersprings from the PRC, as provided in section 781(b) of the Tariff Act of 1930, as amended (''the Act'').[1]

DATES: *Effective Date:* October 23, 2015.

FOR FURTHER INFORMATION CONTACT: Susan Pulongbarit, AD/CVD Operations, Office V, Enforcement and Compliance, International Trade Administration, U.S. Department of Commerce, 14th Street and Constitution Avenue NW., Washington, DC 20230; telephone: (202) 482–4031.

SUPPLEMENTARY INFORMATION:

Background

On December 31, 2014, the Department initiated an anticircumvention inquiry on imports of innersprings from the PRC exported by Goldon.[2] On January 12, 2015, the Department issued a circumvention inquiry questionnaire.[3] On January 22, 2015, we placed information on the record confirming Goldon's receipt of the questionnaire.[4] The Department has,

[1] *See Uncovered Innerspring Units from the People's Republic of China: Notice of Antidumping Duty Order,* 74 FR 7661 (February 19, 2009) (''*Order*'').

[2] *See Uncovered Innerspring Units From the People's Republic of China: Initiation of Anticircumvention Inquiry on Antidumping Duty Order,* 79 FR 78792 (December 31, 2014) (''*Initiation*'').

[3] *See* Letter from the Department, to Goldon, regarding ''Uncovered Innerspring Units from the People's Republic of China: Circumvention Inquiry Questionnaire,'' dated January 12, 2015 (''Circumvention Questionnaire'').

[4] *See* Memo to the File, through Scot T. Fullerton, Program Manager, Office V, AD/CVD Operations, Enforcement and Compliance, from Steven Hampton, International Trade Compliance Analyst, Office V, AD/CVD Operations, Enforcement and Compliance, regarding ''Uncovered Innerspring Units from the People's Republic of China: Anticircumvention Inquiry Questionnaire:

to date, not received any responses to our requests for information from Goldon.

Because Goldon failed to respond to the questionnaire, the record does not contain complete information regarding the factors set forth in section 781(b) of the Tariff Act of 1930 (the ''Act''). Accordingly, we have based our determination on facts otherwise available, pursuant to sections 776(a)(2)(A) and (C) of the Act, applying an adverse inference, pursuant to section 776(b) of the Act.[5]

Scope of the Antidumping Duty Order

The merchandise subject to the order is uncovered innerspring units. The product is currently classified under subheading 9404.29.9010 and has also been classified under subheadings 9404.10.0000, 7326.20.0070, 7320.20.5010, 7320.90.5010, or 7326.20.0071 of the Harmonized Tariff Schedule of the United States (''HTSUS''). The HTSUS subheadings are provided for convenience and customs purposes only; the written product description of the scope of the order is dispositive.[6]

Scope of the Anticircumvention Inquiry

The products covered by this inquiry are innerspring units, as described above, that are manufactured in Malaysia by Goldon with PRC-origin components and other direct materials, such as helical wires, and that are subsequently exported from Malaysia to the United States.

Methodology

The Department has conducted this preliminary determination of circumvention in accordance with section 781(b) of the Act and 19 CFR 351.225(h). For a full description of the methodology underlying our conclusions, *see* the Preliminary Decision Memorandum. The Preliminary Decision Memorandum is a public document and is on file electronically via Enforcement and Compliance's Antidumping and Countervailing Duty Centralized Electronic Service System (''ACCESS''). ACCESS is available to registered users at *http://access.trade.gov* and is available to all parties in the Central Records Unit, room B8024 of the main Department of Commerce building. In addition, the signed Preliminary Decision Memorandum can be accessed directly at *http://enforcement.trade.gov/frn/index.html*. The signed Preliminary Decision Memorandum and the electronic version of the Preliminary Decision Memorandum are identical in content. The Preliminary Decision Memorandum is hereby adopted by this notice.

Affirmative Preliminary Determination of Circumvention

As detailed in the Preliminary Decision Memorandum, the Department preliminarily determines, based on facts available with an adverse inference pursuant to sections 776(a) and (b) of the Act, that innerspring units completed and assembled in Malaysia by Goldon using components from the PRC and exported from Malaysia to the United States are circumventing the *Order*. Moreover, because we are unable to distinguish between those innerspring units that Goldon is exporting to the United States which contain PRC-origin components and those that do not, the Department has preliminarily determined that it is appropriate to instruct U.S. Customs and Border Protection (''CBP'') to suspend liquidation of all entries of innerspring units from Malaysia produced by Goldon as subject to the *Order*.

Suspension of Liquidation

In accordance with 19 CFR 351.225(l)(2), the Department will direct CBP to suspend liquidation and to require a cash deposit of estimated duties at the rate applicable to the exporter, on all unliquidated entries of innerspring units produced by Goldon that were entered, or withdrawn from warehouse, for consumption on or after December 22, 2014, the date of initiation of the anticircumvention inquiry.

Should the Department conduct an administrative review in the future, and determine in the context of that review that Goldon did not produce for export innerspring units using PRC-origin innerspring components, the Department will consider initiating a changed circumstances review pursuant to section 751(b) of the Act to determine if the continued suspension of all innerspring units produced by Goldon is warranted.[7]

Notification to the International Trade Commission

The Department, consistent with section 781(e)(1)(B) of the Act and 19 CFR 351.225(f)(7)(i)(B), has notified the International Trade Commission (''ITC'') of this preliminary determination to include the merchandise subject to this anticircumvention inquiry within the *Order*. Pursuant to section 781(e)(2) of the Act, the ITC may request consultations concerning the Department's proposed inclusion of the subject merchandise. If, after consultations, the ITC believes that a significant injury issue is presented by the proposed inclusion, it will have 15 days to provide written advice to the Department.[8]

Public Comment

Interested parties may submit case briefs within 15 days after the date of publication of these preliminary results of review in the **Federal Register**. Rebuttals to case briefs, which are limited to issues raised in the case briefs, must be filed within five days after the time limit for filing case briefs. Parties who submit case or rebuttal briefs are requested to submit with the argument (a) a statement of the issue, (b) a brief summary of the argument, and (c) a table of authorities. Parties submitting briefs should do so using the Department's electronic filing system, ACCESS.

Pursuant to 19 CFR 351.310(c), interested parties who wish to request a hearing must submit a written request to the Assistant Secretary for Enforcement and Compliance, U.S. Department of Commerce, filed electronically using ACCESS. An electronically filed document must be received successfully in its entirety by the Department's electronic records system, ACCESS, by 5:00 p.m. Eastern Time, within 30 days after the date of publication of this notice.[9] Hearing requests should contain the party's name, address, and telephone number, the number of participants, and a list of the issues parties intend to present at the hearing. If a request for a hearing is made, the Department intends to hold the hearing at the U.S. Department of Commerce, 14th Street and Constitution Avenue NW., Washington, DC 20230, at a time and location to be determined. Prior to the date of the hearing, the Department will contact all parties that submitted case or rebuttal brief to determine if they wish to participate in the hearing.

Documentation to Confirm Goldon's Receipt of the Questionnaire,'' dated January 22, 2015.

[5] For more information, *see* Department Memorandum, ''Anticircumvention Inquiry Regarding the Antidumping Duty Order on Uncovered Innerspring Units from the People's Republic of China: Preliminary Determination Decision Memorandum for Goldon Bedding Manufacturing Sdn. Bhd.,'' dated concurrently with these results (''Preliminary Decision Memorandum'').

[6] *See* Preliminary Decision Memorandum for a complete description of the scope of the *Order*.

[7] *See, e.g., Certain Tissue Paper Products from the People's Republic of China: Affirmative Final Determination of Circumvention of the Antidumping Duty Order,* 76 FR 47554 (August 5, 2011).

[8] *See* section 781(e)(2) of the Act.

[9] *See* 19 CFR 351.310(c).

The Department will then distribute a hearing schedule to the parties prior to the hearing and only those parties listed on the schedule may present issues raised in their briefs.

Final Determination

Pursuant to section 781(f) of the Act, the final determination with respect to this anticircumvention inquiry, including the results of the Department's analysis of any written comments, will be issued no later than December 2, 2015, unless extended.

This preliminary affirmative circumvention determination is published in accordance with section 781(b) of the Act and 19 CFR 351.225.

Dated: October 19, 2015.

Ronald K. Lorentzen,

Acting Assistant Secretary for Enforcement and Compliance.

[FR Doc. 2015–27089 Filed 10–22–15; 8:45 am]

BILLING CODE 3510–DS–P

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

RIN 0648–XE264

New England Fishery Management Council; Public Meeting

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

ACTION: Notice; public meeting.

SUMMARY: The New England Fishery Management Council (Council) is scheduling a public meeting of its Ecosystem Based Fishery Management Committee to consider actions affecting New England fisheries in the exclusive economic zone (EEZ). Recommendations from this group will be brought to the full Council for formal consideration and action, if appropriate.

DATES: This meeting will be held on Tuesday, November 10, 2015 at 9 a.m.

ADDRESSES: The meeting will be held at the Fairfield Inn & Suites, 185 MacArthur Drive, New Bedford, MA 02740; telephone: (774) 634–2000; fax: (774) 634–2001.

Council address: New England Fishery Management Council, 50 Water Street, Mill 2, Newburyport, MA 01950.

FOR FURTHER INFORMATION CONTACT: Thomas A. Nies, Executive Director, New England Fishery Management Council; telephone: (978) 465–0492.

SUPPLEMENTARY INFORMATION:

Agenda

The committee will receive a progress report and provide guidance to the Plan Development Team on the development of an example Fishery Ecosystem Plan (FEP). This meeting will focus on the FEP components, strawman goals and objectives and a summary of how various ecosystem models address FEP data needs. The Committee will also formulate comments on NOAA Fisheries Draft Ecosystem-Based Fisheries Management Policy *(http://s3.amazonaws.com/nefmc.org/2_Draft-EBFM-Policy-9.9.2015-for-release.pdf*). Final comments on the Draft Policy will be approved at the December 2015 Council meeting.

Special Accommodations

This meeting is physically accessible to people with disabilities. Requests for sign language interpretation or other auxiliary aids should be directed to Thomas A. Nies, Executive Director, at (978) 465–0492, at least 5 days prior to the meeting date.

Authority: 16 U.S.C. 1801 *et seq.*

Dated: October 20, 2015.

Tracey L. Thompson,

Acting Deputy Director, Office of Sustainable Fisheries, National Marine Fisheries Service.

[FR Doc. 2015–27005 Filed 10–22–15; 8:45 am]

BILLING CODE 3510–22–P

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

RIN 0648–XE253

Mid-Atlantic Fishery Management Council (MAFMC); Public Meeting

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

ACTION: Notice; public meeting.

SUMMARY: The Mid-Atlantic Fishery Management Council's (MAFMC's) Summer Flounder, Scup, and Black Sea Bass Advisory Panel will hold a public meeting jointly with the Atlantic States Marine Fisheries Commission's (ASMFC's) Summer Flounder, Scup, and Black Sea Bass Advisory Panel.

DATES: The meeting will be held on Tuesday November 17, 2015, from 4 p.m. to 7 p.m. See **SUPPLEMENTARY INFORMATION** for agenda details.

ADDRESSES: The meeting will take place over webinar with a telephone-only connection option. Details on how to connect to the webinar by computer and by telephone will be available at: *http://www.mafmc.org.*

Council address: Mid-Atlantic Fishery Management Council, 800 N. State Street, Suite 201, Dover, DE 19901; telephone: (302) 674–2331; Web site: *www.mafmc.org.*

FOR FURTHER INFORMATION CONTACT: Christopher M. Moore, Ph.D., Executive Director, Mid-Atlantic Fishery Management Council, telephone: (302) 526–5255.

SUPPLEMENTARY INFORMATION: The Mid-Atlantic Fishery Management Council's Summer Flounder, Scup, and Black Sea Bass Advisory Panel, together with the Atlantic States Marine Fisheries Commission's Advisory Panel, will meet on Tuesday November 17, 2015 (see **DATES** and **ADDRESSES**). The purpose of this meeting is to discuss management measures (*e.g.* bag limits, size limits, and seasons) for recreational summer flounder, scup, and black sea bass fisheries in 2016.

A detailed agenda and background documents will be made available on the Council's Web site (*www.mafmc.org*) prior to the meeting.

Special Accommodations

The meeting is physically accessible to people with disabilities. Requests for sign language interpretation or other auxiliary aid should be directed to M. Jan Saunders, (302) 526–5251, at least 5 days prior to the meeting date.

Dated: October 20, 2015.

Tracey L. Thompson,

Acting Deputy Director, Office of Sustainable Fisheries, National Marine Fisheries Service.

[FR Doc. 2015–27004 Filed 10–22–15; 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: Socioeconomics of Guided Wildlife Viewing Operations in Monterey Bay National Marine Sanctuary (MBNMS).

OMB Control Number: 0648–xxxx.

Form Number(s): None.

Type of Request: Regular (request for a new information collection).

Number of Respondents: 56.

Average Hours per Response: 2.5 hours.

Burden Hours: 140.

Needs and Uses: This request is for a new information collection.

NOAA is mentoring student interns from the Monterey Institute for International Studies to estimate the market and non-market economic values associated with non-consumptive recreation uses (*e.g.* whale watching, other wildlife observation, SCUBA diving, snorkeling, beach activities, surfing, wind-surfing, kite boarding, paddle boarding, etc.) in the Monterey Bay National Marine Sanctuary (MBNMS) for those accessing the MBNMS via ''for hire'' operation boats.

We will conduct surveys of the for hire operations that take people out for non-consumptive recreation, to obtain total use by type of activity and the spatial use by type of activity. Information will also be obtained on costs-and-earnings of the operations, knowledge, attitudes and perceptions of sanctuary management strategies and regulations, and demographic information on owner/captains and crews. Surveys will also be conducted of the passengers aboard the for hire operation boats to obtain their market and non-market economic use values for non-consumptive recreation use and how those value change with changes in natural resource attribute conditions and user characteristics. Additional information will be obtained on importance-satisfaction ratings of key natural resource attributes, facilities and services, knowledge, attitudes and perceptions of management strategies and regulations, and demographic profiles of passengers.

Affected Public: Business or other for-profit organizations.

Frequency: One time.

Respondent's Obligation: Voluntary.

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: October 20, 2015.

Sarah Brabson,

NOAA PRA Clearance Officer.

[FR Doc. 2015–26975 Filed 10–22–15; 8:45 am]

BILLING CODE 3510–NK–P

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

RIN 0648–XE265

South Atlantic Fishery Management Council (Council); Public Hearings

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

ACTION: Notice of public hearings.

SUMMARY: The South Atlantic Fishery Management Council (SAFMC) will hold a series of public hearings pertaining to Regulatory Amendment 25 to the Snapper Grouper Fishery Management Plan (FMP) for the South Atlantic and Regulatory Amendment 1 to the Dolphin Wahoo Fishery Management Plan for the Atlantic. Regulatory Amendment 25 to the Snapper Grouper FMP addresses management measures for blueline tilefish, yellowtail snapper and black sea bass. Regulatory Amendment 1 to the Dolphin Wahoo FMP addresses a commercial trip limit for the dolphin fishery in the Atlantic.

DATES: The public hearings will be held via webinar with listening/comment stations from November 9–12, 2015. A webinar with listening/comment stations will be held November 9, 2015 for Regulatory Amendment 25. A webinar with listening/comment stations will be held November 12, 2015 for both Snapper Grouper Regulatory Amendment 25 and Dolphin Wahoo Regulatory Amendment 1.

The public hearings will be conducted via webinar and accessible via the internet from the Council's Web site at *www.safmc.net.* The hearings will begin at 6 p.m. Registration for each webinar is required. Registration information will be posted on the SAFMC Web site at *www.safmc.net* as it becomes available. Webinar registrants may test/confirm their computer set up for the webinar one hour prior to each hearing and contact Mike Collins at (843) 763–1050 to address any questions regarding webinar setup. Local listening/comment stations will be provided at the following locations:

ADDRESSES:

Public Hearings for Regulatory Amendment 25 to the Snapper Grouper FMP:

1. November 9, 2015—Local Listening/Comment Stations: Georgia Department of Natural Resources, Coastal Resources Division, One Conservation Way, Brunswick, GA 31520–8687; phone: (912) 264–7218 and Hilton Garden Inn Charleston Airport, 5265 International Boulevard, North Charleston, SC 29418; phone: (843) 308–9330.

2. November 12, 2015—Local Listening/Comment Station: Dare County Government Complex, Room 168, 1st Floor, 954 Marshall C. Collins Drive, Manteo, NC 27954; phone: (252) 475–5000; and Wingate by Wyndham (Hotel), 2465 State Route 16, St. Augustine, FL 32092; phone: (904) 824–9229.

Public Hearing for Regulatory Amendment 1 to the Dolphin Wahoo FMP

1. November 12, 2015—Local Listening/Comment Station: Dare County Government Complex, Room 168, 1st Floor, 954 Marshall C. Collins Drive, Manteo, NC 27954; phone: (252) 475–5000; and Wingate by Wyndham (Hotel), 2465 State Route 16, St. Augustine, FL 32092; phone: (904) 824–9229.

Council address: South Atlantic Fishery Management Council, 4055 Faber Place Drive, Suite 201, N. Charleston, SC 29405

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

SUPPLEMENTARY INFORMATION:

Regulatory Amendment 25 to the Snapper Grouper FMP

This amendment includes alternatives to:

(1) For blueline tilefish, specify the Acceptable Biological Catch (ABC) for the South Atlantic, adjust Annual Catch Limit (ACL), Optimum Yield (OY) and other management parameters as necessary based on the new ABC; revise the commercial trip limit; and modify the recreational bag limit;

(2) Modify the recreational and commercial fishing year and commercial Accountability Measures for yellowtail snapper; and

(3) Increase the recreational bag limit for black sea bass.

Regulatory Amendment 1 to the Dolphin Wahoo FMP

This amendment includes management alternatives to:

(1) Establish a commercial trip limit for dolphin.

Written comments may be directed to Bob Mahood, Executive Director, SAFMC (see Council address) or via email to*: Mike.Collins@safmc.net.* Note that email comments should specify ''Snapper Grouper Reg Amendment 25'' or ''Dolphin Wahoo Reg Amend 1'' in the Subject *Line of the email according to the comment being submitted.* Public hearing comments for both Snapper Grouper Regulatory Amendment 25 and Dolphin Wahoo Regulatory Amendment 1 will be accepted until 5:00 p.m. on November 16, 2015. Copies of the public hearing documents for each amendment will be posted on the Council's Web site at *www.safmc.net* when they become available.

During the webinars, Council staff will present an overview of the amendment and will be available for informal discussions and to answer questions via webinar. Members of the public will have an opportunity to go on record to record their comments for consideration by the Council. Area Council representatives will be present at the local comment stations.

Special Accommodations

These hearings are physically accessible to people with disabilities. Requests for auxiliary aids should be directed to the Council office (see **ADDRESSES**) 3 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: October 20, 2015.

Tracey L. Thompson,

Acting Deputy Director, Office of Sustainable Fisheries, National Marine Fisheries Service.

[FR Doc. 2015–27006 Filed 10–22–15; 8:45 am]

BILLING CODE 3510–22–P

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

Pacific Fishery Management Council; Online Webinar

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

ACTION: Notice of online webinar.

SUMMARY: The Pacific Fishery Management Council's (Pacific Council's) Scientific and Statistical Committee (SSC) will hold an online webinar to review a revised west coast limited entry trawl individual fishing quota (IFQ) projection model developed by the Pacific Council's Groundfish Management Team (GMT). The online SSC webinar is open to the public.

DATES: The SSC webinar will commence at noon PST, Monday, November 9, 2015 and continue until 2 p.m. or as necessary to complete business for the day.

ADDRESSES: To attend the SSC webinar, please join online at *http://www.gotomeeting.com/online/webinar/join-webinar* and enter the webinar ID: 148–230–579, as well as your name and email address. Once you have joined the webinar, call the toll number 1 (914) 614–3221 and enter 117–723–807 when prompted for the audio access code. Then enter your audio phone pin (shown after joining the webinar). Participants are encouraged to use their telephone, as this is the best practice to avoid technical issues and excessive feedback (see *http://www.pcouncil.org/wp-content/uploads/PFMC_Audio_Diagram_GoToMeeting.pdf* for best practices). System requirements for PC-based attendees: Windows 7, Vista, or XP; for Mac-based attendees: Mac OS X 10.5 or newer; and for mobile attendees: iPhone, iPad, Android phone, or Android tablet (see the *GoToMeeting Webinar Apps*). If you experience technical difficulties and would like assistance, please contact Mr. Kris Kleinschmidt at (503) 820–2280, extension 425. A public listening station will also be provided at the Pacific Council office.

Council address: Pacific Council, 7700 NE Ambassador Place, Suite 101, Portland, OR 97220–1384.

FOR FURTHER INFORMATION CONTACT: Mr. John DeVore, Pacific Council; telephone: (503) 820–2413.

SUPPLEMENTARY INFORMATION: The specific objectives of the SSC webinar are to review revisions to the GMT's west coast limited entry trawl IFQ projection model to ensure the changes recommended by the SSC's Groundfish and Economics Subcommittees in June were implemented and the model behaves as expected. During the webinar, the SSC will consider endorsing the GMT's IFQ model to inform management decisions. No management actions will be decided in this webinar. Public comments during the webinar will be received from attendees at the discretion of the SSC chair.

Although non-emergency issues not identified in the webinar agenda may come before the webinar participants for discussion, those issues may not be the subject of formal action during this webinar. Formal action at the webinar 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 Fishery Conservation and Management Act, provided the public has been notified of the webinar participants' intent to take final action to address the emergency.

Special Accommodations

The public listening station at the Pacific Council office is physically accessible to people with disabilities. Requests for auxiliary aids should be directed to Mr. Kris Kleinschmidt at (503) 820–2280 at least 5 days prior to the webinar date.

Dated: October 20, 2015.

Tracey L. Thompson,

Acting Deputy Director, Office of Sustainable Fisheries, National Marine Fisheries Service.

[FR Doc. 2015–27007 Filed 10–22–15; 8:45 am]

BILLING CODE 3510–22–P

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

RIN 0648–XE270

Magnuson-Stevens Act Provisions; General Provisions for Domestic Fisheries; Application for Exempted Fishing Permits

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

ACTION: Notice; request for comments.

SUMMARY: The Assistant Regional Administrator for Sustainable Fisheries, Greater Atlantic Region, NMFS, has made a preliminary determination that an Exempted Fishing Permit application contains all of the required information and warrants further consideration. This Exempted Fishing Permit would allow commercial fishing vessels to fish outside of the limited access sea scallop regulations in support of study investigating coastal spawning of winter flounder in Southern New England.

Regulations under the Magnuson-Stevens Fishery Conservation and Management Act require publication of this notification to provide interested parties the opportunity to comment on applications for proposed Exempted Fishing Permits.

DATES: Comments must be received on or before November 9, 2015.

ADDRESSES: You may submit written comments by any of the following methods:

- *Email: nmfs.gar.efp@noaa.gov.* Include in the subject line ''DA15–063 CFF SNE Essential Fish Habitat Study EFP.''
- *Mail:* John K. Bullard, Regional Administrator, NMFS, Greater Atlantic

Regional Fisheries Office, 55 Great Republic Drive, Gloucester, MA 01930. Mark the outside of the envelope ''DA15–063 CFF SNE Essential Fish Habitat Study EFP.''

FOR FURTHER INFORMATION CONTACT: Shannah Jaburek, Fisheries Management Specialist, 978–282–8456.

SUPPLEMENTARY INFORMATION: NOAA has awarded the Coonamesset Farm Foundation (CFF) a grant through the 2015 Saltonstall-Kennedy grant program, in support of a project titled ''Investigating Offshore Essential Fish Habitat of Southern New England Winter Flounder.'' To conduct this research, CFF submitted a complete application for an EFP on August 4, 2015. The applicant proposes to investigate questions associated with spawning winter flounder in Southern New England (SNE) by conducting multiple research activities, which include:

1. A paired scallop dredge survey to identify and monitor the distribution of winter flounder;
2. Test dredge gear twine top configurations and apron lengths to reduce finfish bycatch;
3. Attempt to observe winter flounder spawning behavior using a remotely operated vehicle (ROV);
4. Conduct a benthic habitat video survey; and
5. Sample for a winter flounder eggs using a plankton net.

CFF is requesting exemptions that would allow commercial fishing vessels be exempt from the Atlantic sea scallop days-at-sea (DAS) allocations at 50 CFR 648.53(b); crew size restrictions at § 648.51(c); Atlantic sea scallop observer program requirements at § 648.11(g); and possession limits and minimum size requirements specified in 50 CFR part 648, subsections B and D through O, for sampling purposes only. Any fishing activity conducted outside the scope of the exempted fishing activity would be prohibited.

Five vessels would conduct the dredge survey and gear testing on six 5-day trips, for 30 total DAS. Each trip would complete approximately 60 dredge tows per trip for an overall total of 360 tows for the project. The project would also conduct a single video survey trip utilizing a benthic sled. Trips would take place in the open areas of SNE in December 2015–May 2016.

All dredge tows would use two 15-foot (4.57-m) Turtle Deflector Dredges (TDD) and be conducted in tandem for a duration of 30 minutes at a tow speed of approximately 4.8 knots. One dredge would be rigged with a 7-row apron and 60-mesh wide twine top while the other dredge would be rigged with a 5-row apron and 45-mesh wide twine top. To examine factors that may influence flatfish bycatch rates such as habitat characteristics and fish behavior in response to the TDD, each dredge would have an underwater camera attached to the bale bar. When researchers identify large numbers of spawning winter flounder during the dredge survey, they would deploy the ROV to film spawning behavior interactions.

For all tows, researchers would count and weigh sea scallop catch. Researchers would measure scallops from one randomly selected basket from each dredge in 5-mm increments to determine size selectivity. Researchers would sort finfish catch by species then count, weigh, and measure finfish catch in 1-mm increments. Researchers would also weigh, sex, and assess the reproductive stage of all winter flounder greater than 32 cm. The vessels would not retain catch for longer than needed to conduct sampling and vessels would not land any catch for sale. CFF researchers would accompany all trips, and be in charge of sampling activities.

PROJECT CATCH ESTIMATES

Species	lb	kg
Scallops	21,000	9,525
Yellowtail	500	227
Winter Flounder	1,500	680
Windowpane Flounder	2,600	1,179
Monkfish	8,000	3,629
Barndoor Skate	500	227
NE Skate Complex	50,000	22,680
Other Fish	1,500	680

The project would also use a commercial vessel for a single dedicated video trip utilizing a benthic underwater survey sled. At each of the survey stations the benthic sled would be deployed and towed for 5–10 minutes at a speed of 1.5–2 knots. Researchers would attach a live feed video camera transmitting video back to the vessel, and two underwater cameras taking high definition still shots to the benthic sled. There would also be two low level lights attached to the benthic sled in order to illuminate the area for the cameras. The video footage and photos from the benthic sled survey would be compared to still shots take during the dredge surveys. Researchers would also attach a plankton net to the benthic sled. The plankton net would be 101.60 cm long with a 27.94 x 45.72-cm opening, and a mesh size of 0.05 cm. The plankton net would allow researchers to see if there are winter flounder eggs present at each of the survey stations.

CFF has requested these exemptions to allow them to conduct experimental dredge towing without being charged DAS. Participating vessels need crew size waivers to accommodate science personnel and possession waivers will enable them to conduct finfish sampling activities. NMFS would waive observer notification requirements because the research activity is not representative of a commercial scallop fishing trip.

If approved, the applicant may request minor modifications and extensions to the EFP throughout the year. EFP modifications and extensions may be granted without further notice if they are deemed essential to facilitate completion of the proposed research and have minimal impacts that do not change the scope or impact of the initially approved EFP request. Any fishing activity conducted outside the scope of the exempted fishing activity would be prohibited.

Authority: 16 U.S.C. 1801 *et seq.*

Dated: October 20, 2015.

Emily H. Menashes,

Acting Director, Office of Sustainable Fisheries, National Marine Fisheries Service.

[FR Doc. 2015–27003 Filed 10–22–15; 8:45 am]

BILLING CODE 3510–22–P

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

RIN 0648–XE230

Atlantic Coastal Fisheries Cooperative Management Act Provisions; Horseshoe Crabs; Application for Exempted Fishing Permit, 2015; Reopening of Comment Period

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

ACTION: Notification of a proposal to conduct exempted fishing; reopening of comment period.

SUMMARY: This action reopens the comment period for an application for an exempted fishing permit for horseshoe crab that published on October 7, 2015. The original comment period closed 13 days later on October 19, 2015, which is two days shorter than the 15-day minimum comment time period required in our regulations. We are therefore reopening the comment period through October 27, 2015, to make-up for this shortfall and to provide additional opportunity for public comment.

DATES: Written comments must be received on or before October 27, 2015.

ADDRESSES: Written comments should be sent to Alan Risenhoover, Director, Office of Sustainable Fisheries, NMFS, 1315 East-West Highway, Room 13362, Silver Spring, MD 20910. Mark the outside of the envelope ''Comments on Horseshoe Crab EFP Proposal.''

Comments may also be sent via fax to (301) 713–0596. Comments on this notice may also be submitted by email to: *nmfs.state-federal@noaa.gov.* Include in the subject line of the email comment the following document identifier: ''Horseshoe Crab EFP Proposal Comments.''

FOR FURTHER INFORMATION CONTACT: Derek Orner, Office of Sustainable Fisheries, (301) 427–8567.

SUPPLEMENTARY INFORMATION: A notification of a proposal to conduct exempted fishing was published on October 7, 2015 (80 FR 60633) that would allow the harvest of up to 10,000 horseshoe crabs from the Carl N. Schuster Jr. Horseshoe Crab Reserve for biomedical purposes and require, as a condition of the exempted fishing permit (EFP), the collection of data related to the status of horseshoe crabs within the reserve. The Director, Office of Sustainable Fisheries, has made a preliminary determination that the subject EFP application submitted by Limuli Laboratories of Cape May Court House, NJ, contains all the required information and warrants further consideration.

The notification of EFP application published in the **Federal Register** with a 13-day comment period that closed on October 19, 2015. Due to a clerical oversight, NMFS provided the public with a 13-day comment period instead of the 15-day comment period required by our regulations at 50 CFR 600.745. As a result, NMFS is extending the comment period to allow for additional time for public comment for interested parties to provide comment on this activity. Thus, NMFS is reopening the comment period through October 27, 2015.

Authority: 16 U.S.C. 1801 *et seq.*

Dated: October 19, 2015.

Emily H. Menashes,

Acting Director, Office of Sustainable Fisheries, National Marine Fisheries Service.

[FR Doc. 2015–26897 Filed 10–22–15; 8:45 am]

BILLING CODE 3510–22–P

BUREAU OF CONSUMER FINANCIAL PROTECTION

[Docket No: CFPB–2015–0043]

Agency Information Collection Activities: Submission for OMB Review; Comment Request

AGENCY: Bureau of Consumer Financial Protection.

ACTION: Notice and request for comment.

SUMMARY: In accordance with the Paperwork Reduction Act of 1995 (PRA), the Consumer Financial Protection Bureau (Bureau) is proposing to renew the Office of Management and Budget (OMB) approval for an existing information collection titled, ''Generic Information Collection Plan for the Collection of Qualitative Feedback on Bureau Service Delivery.''

DATES: Written comments are encouraged and must be received on or before November 23, 2015 to be assured of consideration.

ADDRESSES: You may submit comments, identified by the title of the information collection, OMB Control Number (see below), and docket number (see above), by any of the following methods:

- *Electronic: http://www.regulations.gov.* Follow the instructions for submitting comments.
- *OMB:* Office of Management and Budget, New Executive Office Building, Room 10235, Washington, DC 20503 or fax to (202) 395–5806. Mailed or faxed comments to OMB should be to the attention of the OMB Desk Officer for the Bureau of Consumer Financial Protection. *Please note that comments submitted after the comment period will not be accepted.* In general, all comments received will become public records, including any personal information provided. Sensitive personal information, such as account numbers or social security numbers, should not be included.

FOR FURTHER INFORMATION CONTACT: Documentation prepared in support of this information collection request is available at *www.reginfo.gov* (this link active on the day following publication of this notice). Select ''Information Collection Review,'' under ''Currently under review, use the dropdown menu ''Select Agency'' and select ''Consumer Financial Protection Bureau'' (recent submissions to OMB will be at the top of the list). The same documentation is also available at *http://www.regulations.gov.* Requests for additional information should be directed to the Consumer Financial Protection Bureau, (Attention: PRA Office), 1700 G Street NW., Washington, DC 20552, (202) 435–9575, or email: *PRA@cfpb.gov. Please do not submit comments to this email box.*

SUPPLEMENTARY INFORMATION:

Title of Collection: Generic Information Collection Plan for the Collection of Qualitative Feedback on Bureau Service Delivery.

OMB Control Number: 3170–0024.

Type of Review: Extension without change of a currently approved collection.

Affected Public: Individual or Households; State, Local, or Tribal Governments; and Private Sector.

Estimated Number of Respondents: 30,000.

Estimated Total Annual Burden Hours: 7,875.

Abstract: This generic information collection plan provides for the collection of qualitative feedback from consumers, financial institutions, and stakeholders on a wide range of services the Bureau provides in an efficient, timely manner, in accordance with the Bureau's commitment to improving service delivery. By qualitative feedback, the Bureau means information that provides useful insights on, for example, comprehension, usability, perceptions, and opinions, but are not statistical surveys that yield quantitative results that can be generalized to the population of study. The Bureau expects this feedback to include insights into consumer, financial institution, or stakeholder perceptions, experiences, and expectations, provide an early warning of issues with service, or focus attention on areas where communication, training or changes in operations might improve delivery of products or services. These collections will allow for ongoing, collaborative, and actionable communications between the Bureau and consumers, financial institutions, and stakeholders. It will also allow feedback to contribute directly to the improvement of program management.

This submission is requesting OMB to renewal for additional three (3) years its approval of this generic information collection plan.

Request for Comments: The Bureau issued a 60-day **Federal Register** notice on June 15, 2015 (80 FR 34148). Comments were solicited and continue to be invited on: (a) Whether the collection of information is necessary for the proper performance of the functions of the Bureau, including whether the information will have practical utility; (b) The accuracy of the Bureau's estimate of the burden of the collection of information, including the validity of the methods and the assumptions used; (c) Ways to enhance the quality, utility, and clarity of the information to be collected; and (d) Ways to minimize the burden of the collection of information on respondents, including through the use of automated collection techniques or other forms of information technology. Comments submitted in response to this notice will be summarized and/or included in the request for OMB approval. All comments will become a matter of public record.

Dated: October 20, 2015.

Darrin A. King,

Paperwork Reduction Act Officer, Bureau of Consumer Financial Protection.

[FR Doc. 2015–27079 Filed 10–22–15; 8:45 am]

BILLING CODE 4810–AM–P

BUREAU OF CONSUMER FINANCIAL PROTECTION

[Docket No: CFPB–2015–0044]

Agency Information Collection Activities: Submission for OMB Review; Comment Request

AGENCY: Bureau of Consumer Financial Protection.

ACTION: Notice and request for comment.

SUMMARY: In accordance with the Paperwork Reduction Act of 1995 (PRA), the Consumer Financial Protection Bureau (Bureau) is proposing a new information collection for Office of Management and Budget (OMB) approval titled, ''Owning a Home Evaluation Study.''

DATES: Written comments are encouraged and must be received on or before November 23, 2015 to be assured of consideration.

ADDRESSES: You may submit comments, identified by the title of the information collection, OMB Control Number (see below), and docket number (see above), by any of the following methods:

- *Electronic: http://www.regulations.gov.* Follow the instructions for submitting comments.
- *OMB:* Office of Management and Budget, New Executive Office Building, Room 10235, Washington, DC 20503 or fax to (202) 395–5806. Mailed or faxed comments to OMB should be to the attention of the OMB Desk Officer for the Bureau of Consumer Financial Protection. *Please note that comments submitted after the comment period will not be accepted.* In general, all comments received will become public records, including any personal information provided. Sensitive personal information, such as account numbers or social security numbers, should not be included.

FOR FURTHER INFORMATION CONTACT: Documentation prepared in support of this information collection request is available at *www.reginfo.gov* (this link active on the day following publication of this notice). Select ''Information Collection Review,'' under Currently under review, use the dropdown menu ''Select Agency'' and select ''Consumer Financial Protection Bureau'' (recent submissions to OMB will be at the top of the list). The same documentation is also available at *http://www.regulations.gov.* Requests for additional information should be directed to the Consumer Financial Protection Bureau, (Attention: PRA Office), 1700 G Street NW., Washington, DC 20552, (202) 435–9575, or email: *PRA@cfpb.gov. Please do not submit comments to this email box.*

SUPPLEMENTARY INFORMATION:

Title of Collection: Owning a Home Evaluation Study.

OMB Control Number: 3170–XXXX (Will be assigned upon OMB approval).

Type of Review: New Collection (Request for a new OMB control number).

Affected Public: Individuals or households.

Estimated Number of Respondents: 170,200.

Estimated Total Annual Burden Hours: 12,480.

Abstract: The Dodd Frank Act directs the Bureau to develop a program of consumer education and engagement. As part of that program, the Bureau has developed a suite of online tools and resources, known as the Owning a Home project, to help consumers make better, more informed decisions about mortgages. The purpose of this information collection is to learn about the behavioral mechanisms and evaluate the hypotheses underlying the Owning a Home project. This information collection is structured as a randomized-controlled trial field study.

Request for Comments: The Bureau issued a 60-day **Federal Register** notice on September 26, 2014 (79 FR 57892). Comments were solicited and continue to be invited on: (a) Whether the collection of information is necessary for the proper performance of the functions of the Bureau, including whether the information will have practical utility; (b) The accuracy of the Bureau's estimate of the burden of the collection of information, including the validity of the methods and the assumptions used; (c) Ways to enhance the quality, utility, and clarity of the information to be collected; and (d) Ways to minimize the burden of the collection of information on respondents, including through the use of automated collection techniques or other forms of information technology. Comments submitted in response to this notice will be summarized and/or included in the request for OMB approval. All comments will become a matter of public record.

Dated: October 20, 2015.

Darrin A. King,

Paperwork Reduction Act Officer, Bureau of Consumer Financial Protection.

[FR Doc. 2015–27078 Filed 10–22–15; 8:45 am]

BILLING CODE 4810–AM–P

CORPORATION FOR NATIONAL AND COMMUNITY SERVICE

Proposed Information Collection; Comment Request

AGENCY: Corporation for National and Community Service.

ACTION: Notice.

SUMMARY: The Corporation for National and Community Service (CNCS), as part of its continuing effort to reduce paperwork and respondent burden, conducts a pre-clearance consultation program to provide the general public and federal agencies with an opportunity to comment on proposed and/or continuing collections of information in accordance with the Paperwork Reduction Act of 1995 (PRA) (44 U.S.C. 3506(c)(2)(A)). This program helps to ensure that requested data can be provided in the desired format, reporting burden (time and financial resources) is minimized, and the impact of the requirement on respondents can be properly assessed.

Currently, CNCS is soliciting comments concerning its recordkeeping requirement in 45 CFR 2540.205 and 2540.206. CNCS grantees and subgrantees must maintain records to document completion of required National Service Criminal History Checks. This is not a notice of proposed rulemaking.

DATES: Written comments must be submitted to the individual and office listed in the **ADDRESSES** section by December 22, 2015.

ADDRESSES: You may submit comments, identified by the title of the information collection activity, by any of the following methods:

(1) *By mail sent to:* Corporation for National and Community Service, Aaron Olszewski, Office of General Counsel; 1201 New York Avenue NW., Washington, DC 20525.

(2) *By hand delivery or by courier* to the CNCS mailroom at Room 8100 at the mail address given in paragraph (1) above, between 9:00 a.m. and 4:00 p.m. Eastern Time, Monday through Friday, except Federal holidays.

(3) *By fax to:* (202) 606–3467, Attention: Paperwork Reduction Act.

(4) *Electronically,* through *www.regulations.gov.*

Individuals who use a telecommunications device for the deaf (TTY–TDD) may call 1–800–833–3722 between 8:00 a.m. and 8:00 p.m. Eastern Time, Monday through Friday.

FOR FURTHER INFORMATION CONTACT: Aaron Olszewski, 202–606–6670, or by email at *aolszewski@cns.gov.*

SUPPLEMENTARY INFORMATION: This is not a notice of proposed rulemaking. CNCS is particularly interested in comments that:

- Evaluate whether the proposed collection of information is necessary for the efficient performance of the functions of CNCS, including whether the information will have practical utility;
- 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;
- Enhance the quality, utility, and clarity of the information to be collected; and
- Minimize the burden of the collection of information on those who are expected to respond, including 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).

Background

Section 189D of the National and Community Service Act of 1990, as amended, requires CNCS grantees and subgrantees to conduct a National Service Criminal History Check on individuals in covered positions. Documenting compliance with the requirement is critical to that responsibility.

Current Action

CNCS requests renewal of the previous approval.

The requirements will be used in the same manner as the existing application. CNCS also seeks to continue using the current application until the revised application is approved by OMB. The current application is due to expire on February 29, 2016.

Type of Review: Renewal of Approved Recordkeeping Requirement.

Agency: Corporation for National and Community Service.

Title: National Service Criminal History Check Recordkeeping Requirement.

OMB Number: 3045–0145.

Agency Number: None.

Affected Public: CNCS Grantees and Subgrantees.

Total Respondents: 112,357.

Frequency: Three times per covered position.

Average Time per Response: Five minutes.

Estimated Total Burden Hours: 28,089 hours.

Total Burden Cost (capital/startup): None.

Total Burden Cost (operating/maintenance): None.

Comments submitted in response to this notice will be summarized and/or included in the request for Office of Management and Budget approval; they will also become a matter of public record.

Dated: October 20, 2015.

Jeremy Joseph,

General Counsel.

[FR Doc. 2015–26996 Filed 10–22–15; 8:45 am]

BILLING CODE 6050–28–P

DEPARTMENT OF DEFENSE

Office of the Secretary

Judicial Proceedings Since Fiscal Year 2012 Amendments Panel (Judicial Proceedings Panel); Notice of Federal Advisory Committee Meeting

AGENCY: Department of Defense.

ACTION: Notice of meeting.

SUMMARY: The Department of Defense is publishing this notice to announce the following Federal Advisory Committee meeting of the Judicial Proceedings since Fiscal Year 2012 Amendments Panel (''the Judicial Proceedings Panel'' or ''the Panel''). The meeting is open to the public.

DATES: A meeting of the Judicial Proceedings Panel will be held on Friday, November 6, 2015. The Public Session will begin at 9:00 a.m. and end at 4:45 p.m.

ADDRESSES: The Holiday Inn Arlington at Ballston, 4610 N. Fairfax Drive, Arlington, Virginia 22203.

FOR FURTHER INFORMATION CONTACT: Ms. Julie Carson, Judicial Proceedings Panel, One Liberty Center, 875 N. Randolph Street, Suite 150, Arlington, VA 22203. Email: *whs.pentagon.em.mbx.judicial-panel@mail.mil.*. Phone: (703) 693-3849. Web site: *http://jpp.whs.mil*.

SUPPLEMENTARY INFORMATION: Due to circumstances beyond the control of the Designated Federal Officer and the Department of Defense, the Judicial Proceedings since Fiscal Year 2012 Amendments Panel (''the Judicial Proceedings Panel was unable to provide public notification of its meeting of November 6, 2015, as required by 41 CFR 102–3.150(a). Accordingly, the Advisory Committee Management Officer for the Department of Defense, pursuant to 41 CFR 102–3.150(b), waives the 15-calendar day notification requirement.

This public meeting is being held under the provisions of the Federal Advisory Committee Act of 1972 (5 U.S.C., Appendix, as amended), the Government in the Sunshine Act of 1976 (5 U.S.C. 552b, as amended), and 41 CFR 102–3.150.

Purpose of the Meeting: In Section 576(a)(2) of the National Defense Authorization Act for Fiscal Year 2013 (Pub. L. 112–239), as amended, Congress tasked the Judicial Proceedings Panel to conduct an independent review and assessment of judicial proceedings conducted under the Uniform Code of Military Justice (UCMJ) involving adult sexual assault and related offenses since the amendments made to the UCMJ by section 541 of the National Defense Authorization Act for Fiscal Year 2012 (Public Law 112–81; 125 Stat. 1404), for the purpose of developing recommendations for improvements to such proceedings. At this meeting, the Panel will hear about a recently completed assessment of the Uniform Code of Military Justice conducted by the Military Justice Review group. It will also continue its review of military justice data for sexual assault crimes and comparative sentencing schemes and continue deliberations on issues relating to retaliation against individuals who report incidents of sexual assault within the military. The Panel is interested in written and oral comments from the public, including non-governmental organizations, relevant to these issues or any of the Panel's tasks.

Agenda

- 9:00–10:15 Overview of Issues Examined by the Military Justice Review Group
- 10:30–11:30 Department of Defense Sexual Assault Prevention and Response Office Overview of Statistics from Annual Reports to Congress

- 11:30–12:00 Staff Presentation: Research and Methodology Used to Obtain and Analyze Information about the Military's Adjudication of Sexual Assault Crimes
- 12:00–1:00 Lunch
- 1:00–2:00 Staff Presentation: Descriptive Overview of Sexual Assault Case Outcomes and Comparative Data
- 2:00–3:00 Panel Discussion: Identifying Focus Areas for Further Examination Regarding Military Sexual Assault Adjudications
- 3:00–4:30 Deliberations: Retaliation Against Victims of Sexual Assault
- 4:30–4:45 Public Comment

Availability of Materials for the Meeting: A copy of the November 6, 2015 public meeting agenda or any updates or changes to the agenda, to include individual speakers not identified at the time of this notice, as well as other materials provided to Panel members for use at the public meeting, may be obtained at the meeting or from the Panel's Web site at *http://jpp.whs.mil*.

Public's Accessibility to the Meeting: Pursuant to 5 U.S.C. 552b and 41 CFR 102–3.140 through 102–3.165, and the availability of space, this meeting is open to the public. Seating is limited and is on a first-come basis.

Special Accommodations: Individuals requiring special accommodations to access the public meeting should contact the Judicial Proceedings Panel at *whs.pentagon.em.mbx.judicial-panel@mail.mil* at least five (5) business days prior to the meeting so that appropriate arrangements can be made.

Procedures for Providing Public Comments: Pursuant to 41 CFR 102–3.140 and section 10(a)(3) of the Federal Advisory Committee Act of 1972, the public or interested organizations may submit written comments to the Panel about its mission and topics pertaining to this public session. Written comments must be received by the JPP at least five (5) business days prior to the meeting date so that they may be made available to the Judicial Proceedings Panel for their consideration prior to the meeting. Written comments should be submitted via email to the Judicial Proceedings Panel at *whs.pentagon.em.mbx.judicial-panel@mail.mil* in the following formats: Adobe Acrobat or Microsoft Word. Please note that since the Judicial Proceedings Panel operates under the provisions of the Federal Advisory Committee Act, as amended, all written comments will be treated as public documents and will be made available for public inspection. If members of the public are interested in making an oral statement, a written statement must be submitted along with a request to provide an oral statement. Oral presentations by members of the public will be permitted from 4:30 p.m. to 4:45 p.m. on November 6, 2015 in front of the Panel members. The number of oral presentations to be made will depend on the number of requests received from members of the public on a first-come basis. After reviewing the requests for oral presentation, the Chairperson and the Designated Federal Officer will, if they determine the statement to be relevant to the Panel's mission, allot five minutes to persons desiring to make an oral presentation.

Committee's Designated Federal Officer: The Panel's Designated Federal Officer is Ms. Maria Fried, Department of Defense, Office of the General Counsel, 1600 Defense Pentagon, Room 3B747, Washington, DC 20301–1600.

Dated: October 20, 2015.

Morgan F. Park,

Alternate OSD Federal Register Liaison Officer, Department of Defense.

[FR Doc. 2015–27055 Filed 10–22–15; 8:45 am]

BILLING CODE 5001–06–P

DEPARTMENT OF DEFENSE

Office of the Secretary

[Docket ID: DoD–2015–OS–0101]

Privacy Act of 1974; System of Records

AGENCY: Office of the Secretary of Defense, DoD.

ACTION: Notice to alter an existing System of Records.

SUMMARY: The Office of the Secretary of Defense proposes to alter an existing system of records, DPR 32, entitled ''Employer Support of the Guard and Reserve Ombudsman and Outreach Programs'' to record information related to the mediation of disputes and answering of inquiries related to the USERRA; by tracking case assignments and mediation results of potential conflicts between employers and the National Guard, Reserves, or NDMS members they employ; and by reporting statistics related to the Ombudsman Program in aggregate and at the state committee-level. These records are also used as a management tool for statistical analysis, tracking, reporting, evaluating program effectiveness and conducting research.

DATES: Comments will be accepted on or before November 23, 2015. This proposed action will be effective the day following the end of the comment period unless comments are received which result in a contrary determination.

ADDRESSES: You may submit comments, identified by docket number and title, by any of the following methods:

* *Federal Rulemaking Portal: http://www.regulations.gov*. Follow the instructions for submitting comments.

* *Mail:* Department of Defense, Office of the Deputy Chief Management Officer, Directorate of Oversight and Compliance, Regulatory and Audit Matters Office, 9010 Defense Pentagon, Washington, DC 20301–9010.

Instructions: All submissions received must include the agency name and docket number for this **Federal Register** document. The general policy for comments and other submissions from members of the public is to make these submissions available for public viewing on the Internet at *http://www.regulations.gov* as they are received without change, including any personal identifiers or contact information.

FOR FURTHER INFORMATION CONTACT: Ms. Cindy Allard, Chief, OSD/JS Privacy Office, Freedom of Information Directorate, Washington Headquarters Service, 1155 Defense Pentagon, Washington, DC 20301–1155, or by phone at (571)372–0461.

SUPPLEMENTARY INFORMATION: The Office of the Secretary of Defense notices for systems of records subject to the Privacy Act of 1974 (5 U.S.C. 552a), as amended, have been published in the **Federal Register** and are available from the address in **FOR FURTHER INFORMATION CONTACT** or at *http://dpcld.defense.gov/* . The proposed system report, as required by 5 U.S.C. 552a(r) of the Privacy Act of 1974, as amended, was submitted on August 27, 2015, to the House Committee on Oversight and Government Reform, the Senate Committee on Governmental Affairs, and the Office of Management and Budget (OMB) pursuant to paragraph 4c of Appendix I to OMB Circular No. A–130, ''Federal Agency Responsibilities for Maintaining Records About Individuals,'' dated February 8, 1996 (February 20, 1996, 61 FR 6427).

Dated: October 20, 2015.

Morgan F. Park,

Alternate OSD Federal Register Liaison Officer, Department of Defense.

DPR 32

SYSTEM NAME:

Employer Support of the Guard and Reserve Ombudsman and Outreach

Programs (November 14, 2007, 72 FR 64058).

CHANGES:

SYSTEM IDENTIFIER:

Delete entry and replace with ''DHRA 16.''

SYSTEM NAME:

Delete entry and replace with ''Inquiry and Case Management System (ICMS).''

SYSTEM LOCATION:

Delete entry and replace with ''Defense Information Systems Agency (DISA), Computing Directorate Mechanicsburg, 5450 Carlisle Pike, Mechanicsburg, PA 17050–2411.

Backup: Iron Mountain, 1665 S 5350 W., Salt Lake City, UT 84104–4721.''

CATEGORIES OF INDIVIDUALS COVERED BY THE SYSTEM:

Delete entry and replace with ''Members of the National Guard, Reserves, and National Disaster Medical System (NDMS) who submit inquiries or request mediation; Employer Support of the Guard and Reserve (ESGR) employees; civilian employers; contractors and volunteers who handle inquiries and cases; and those who submit inquiries.''

CATEGORIES OF RECORDS IN THE SYSTEM:

Delete entry and replace with ''Individual's full name, home address, phone number, email address; current Uniformed Service and Service member pay grade; ESGR case number; type of Uniformed Services Employment and Reemployment Rights Act (USERRA) issue; employer name, employer type, employer's contact name, contact phone, email and address; name, email and state committee/ESGR affiliation of ESGR employee, contractor, or volunteer that handles an inquiry or mediation case; and case notes.''

AUTHORITY FOR MAINTENANCE OF THE SYSTEM:

Delete entry and replace with ''38 U.S.C. 43, Employment and Reemployment Rights of Members of the Uniformed Services; 5 U.S.C. 574, Confidentiality; 5 U.S.C. Part I, Chapter 5, Subchapter IV, Alternative Means of Dispute Resolution in the Administrative Process; 42 U.S.C. 300hh–11, National Disaster Medical System, ((d)(3) Employment and reemployment rights); 20 CFR 1002, Regulations Under the Uniformed Services Employment and Reemployment Rights Act of 1994; 5 CFR 353, Restoration to Duty from Uniformed Service or Compensable Injury; DoD Directive 1250.01, National Committee for Employer Support of the Guard and Reserve (NCESGR); DoD Instruction 1205.22, Employer Support of the Guard and Reserve; and DoD Instruction 1205.12, Civilian Employment and Reemployment Rights of Applicants for, and Service Members and Former Service Members of the Uniformed Services.''

PURPOSE(S):

Delete entry and replace with ''To record information related to the mediation of disputes and answering of inquiries related to the USERRA; by tracking case assignments and mediation results of potential conflicts between employers and the National Guard, Reserves, or NDMS members they employ; and by reporting statistics related to the Ombudsman Program in aggregate and at the state committee-level. These records are also used as a management tool for statistical analysis, tracking, reporting, evaluating program effectiveness and conducting research.''

ROUTINE USES OF RECORDS MAINTAINED IN THE SYSTEM, INCLUDING CATEGORIES OF USERS AND THE PURPOSES OF SUCH USES:

Delete entry and replace with ''In addition to those disclosures generally permitted under 5 U.S.C. 552a(b) of the Privacy Act of 1974, as amended, the records contained herein may be disclosed outside the DoD as a routine use pursuant to 5 U.S.C. 552a(b)(3) as follows:

To Department of Labor for Congressionally-mandated USERRA reporting (38 U.S.C. Employment and Reemployment Rights of Members of the Uniformed Services § 4432, Reports).

Law Enforcement Routine Use: If a system of records maintained by a DoD Component to carry out its functions indicates a violation or potential violation of law, whether civil, criminal, or regulatory in nature, and whether arising by general statute or by regulation, rule, or order issued pursuant thereto, the relevant records in the system of records may be referred, as a routine use, to the agency concerned, whether federal, state, local, or foreign, charged with the responsibility of investigating or prosecuting such violation or charged with enforcing or implementing the statute, rule, regulation, or order issued pursuant thereto.

Disclosure When Requesting Information Routine Use: A record from a system of records maintained by a DoD Component may be disclosed as a routine use to a federal, state, or local agency maintaining civil, criminal, or other relevant enforcement information or other pertinent information, such as current licenses, if necessary to obtain information relevant to a DoD Component decision concerning the hiring or retention of an employee, the issuance of a security clearance, the letting of a contract, or the issuance of a license, grant, or other benefit.

Disclosure of Requested Information Routine Use: A record from a system of records maintained by a DoD Component may be disclosed to a federal agency, in response to its request, in connection with the hiring or retention of an employee, the issuance of a security clearance, the reporting of an investigation of an employee, the letting of a contract, or the issuance of a license, grant, or other benefit by the requesting agency, to the extent that the information is relevant and necessary to the requesting agency's decision on the matter.

Congressional Inquiries Disclosure Routine Use: Disclosure from a system of records maintained by a DoD Component may be made to a congressional office from the record of an individual in response to an inquiry from the congressional office made at the request of that individual.

Disclosure to the Office of Personnel Management Routine Use: A record from a system of records subject to the Privacy Act and maintained by a DoD Component may be disclosed to the Office of Personnel Management (OPM) concerning information on pay and leave, benefits, retirement deduction, and any other information necessary for the OPM to carry out its legally authorized government-wide personnel management functions and studies.

Disclosure to the Department of Justice for Litigation Routine Use: A record from a system of records maintained by a DoD Component may be disclosed as a routine use to any component of the Department of Justice for the purpose of representing the Department of Defense, or any officer, employee or member of the Department in pending or potential litigation to which the record is pertinent.

Disclosure of Information to the National Archives and Records Administration Routine Use: A record from a system of records maintained by a DoD Component may be disclosed as a routine use to the National Archives and Records Administration for the purpose of records management inspections conducted under authority of 44 U.S.C. 2904 and 2906.

Disclosure to the Merit Systems Protection Board Routine Use: A record from a system of records maintained by a DoD Component may be disclosed as a routine use to the Merit Systems Protection Board, including the Office of the Special Counsel for the purpose of litigation, including administrative proceedings, appeals, special studies of the civil service and other merit systems, review of OPM or component rules and regulations, investigation of alleged or possible prohibited personnel practices; including administrative proceedings involving any individual subject of a DoD investigation, and such other functions, promulgated in 5 U.S.C. 1205 and 1206, or as may be authorized by law.

Data Breach Remediation Purposes Routine Use: A record from a system of records maintained by a Component may be disclosed to appropriate agencies, entities, and persons when (1) The Component suspects or has confirmed that the security or confidentiality of the information in the system of records has been compromised; (2) the Component has determined that as a result of the suspected or confirmed compromise there is a risk of harm to economic or property interests, identity theft or fraud, or harm to the security or integrity of this system or other systems or programs (whether maintained by the Component or another agency or entity) that rely upon the compromised information; and (3) the disclosure made to such agencies, entities, and persons is reasonably necessary to assist in connection with the Components efforts to respond to the suspected or confirmed compromise and prevent, minimize, or remedy such harm.

The DoD Blanket Routine Uses set forth at the beginning of the Office of the Secretary of Defense (OSD) compilation of systems of records notices may apply to this system. The complete list of DoD Blanket Routine Uses can be found online at: *http://dpcld.defense.gov/Privacy/SORNsIndex/BlanketRoutineUses.aspx*''

STORAGE:

Delete entry and replace with ''Electronic storage media.''

RETRIEVABILITY:

Delete entry and replace with ''Individual's full name and ESGR case number.''

SAFEGUARDS:

Delete entry and replace with ''Physical controls include combination locks, cipher locks, key cards, identification badges, closed circuit televisions, and controlled screenings. Technical controls include user identification and password, intrusion detection system, encryption, Common Access Card, firewall, virtual private network, role-based access controls, and two-factor authentication. Administrative controls include periodic security audits, regular monitoring of users' security practices, methods to ensure only authorized personnel access information, encryption of backups containing sensitive data, backups secured off-site, and use of visitor registers.''

RETENTION AND DISPOSAL:

Delete entry and replace with ''Temporary. Contact information (email, phone number, details/notes of questions asked) from the inquiry data destroy 90 days after inquiry has been closed.

Masterfile: Destroy 3 years after settlement is implemented or case is discontinued.''

SYSTEM MANAGER(S) AND ADDRESS:

Delete entry and replace with ''Executive Director, Headquarters, Employer Support of the Guard and Reserve, 4800 Mark Center Drive, Alexandria, VA 22350–1200.''

NOTIFICATION PROCEDURE:

Delete entry and replace with ''Individuals seeking to determine if information about themselves is contained in this system of records should address written inquiries to the Executive Director, Headquarters, Employer Support of the Guard and Reserve, 4800 Mark Center Drive, Alexandria, VA 22350–1200.

Signed, written requests should contain the individual's full name and personal contact information (address, phone number, and email).''

RECORD ACCESS PROCEDURES:

Delete entry and replace with ''Individuals seeking access to records about themselves contained in this system should address written inquiries to the Office of the Secretary of Defense/Joint Staff, Freedom of Information Act Requester Service Center, Office of Freedom of Information, 1155 Defense Pentagon, Washington, DC 20301–1155.

Signed, written requests should include the individual's full name and personal contact information (address, phone number, email) and the name and number of this system of records notice.''

* * * * *

RECORD SOURCE CATEGORIES:

Delete entry and replace with ''Individual, and Member Management System (MMS).''

* * * * *

[FR Doc. 2015–27012 Filed 10–22–15; 8:45 am]

BILLING CODE 5001–06–P

DEPARTMENT OF DEFENSE

Office of the Secretary

Defense Health Board; Notice of Federal Advisory Committee Meeting

AGENCY: Department of Defense (DoD).

ACTION: Notice of Federal Advisory Committee meeting.

SUMMARY: The Department of Defense is publishing this notice to announce that the following Federal Advisory Committee meeting of the Defense Health Board will take place.

DATES:

Monday, November 9, 2015

9:30 a.m.–11:30 a.m. (Open Session)
11:30 a.m.–12:30 p.m. (Administrative Working Meeting)
12:30 p.m.–5:00 p.m. (Open Session)

ADDRESSES: Davis Conference Center, 7633 Bayshore Boulevard, MacDill Air Force Base, Florida 33621 (Pre-meeting screening and registration required; see guidance in **SUPPLEMENTARY INFORMATION**, ''Public's Accessibility to the Meeting'').

FOR FURTHER INFORMATION CONTACT: The Executive Director of the Defense Health Board is Ms. Christine Bader, 7700 Arlington Boulevard, Suite 5101, Falls Church, Virginia 22042, (703) 681–6653, Fax: (703) 681–9539, *christine.e.bader.civ@mail.mil.* For meeting information, please contact Ms. Kendal Brown, 7700 Arlington Boulevard, Suite 5101, Falls Church, Virginia 22042, *kendal.l.brown2.ctr@mail.mil,* (703) 681–6670, Fax: (703) 681–9539.

SUPPLEMENTARY INFORMATION: This meeting is being held under the provisions of the Federal Advisory Committee Act of 1972 (5 U.S.C., Appendix, as amended), the Government in the Sunshine Act of 1976 (5 U.S.C. 552b, as amended), and 41 CFR 102–3.150, and in accordance with section 10(a)(2) of the Federal Advisory Committee Act.

Additional information, including the agenda and electronic registration, is available at the DHB Web site, *http://www.health.mil/About-MHS/Other-MHS-Organizations/Defense-Health-Board/Meetings.*

Purpose of the Meeting

The purpose of the meeting is to conduct a decision briefing for deliberation and provide progress updates on specific taskings before the DHB. In addition, the DHB will receive information briefings on current issues or lessons learned related to military medicine, health policy, health research, disease/injury prevention, health promotion, and healthcare delivery.

Agenda

Pursuant to 5 U.S.C. 552b, as amended, and 41 CFR 102–3.140 through 102–3.165 and subject to availability of space, the DHB meeting is open to the public from 9:30 a.m. to 11:30 a.m. and 12:30 p.m. to 5:00 p.m. on November 9, 2015. The DHB anticipates deliberating a decision briefing from the Neurological/Behavioral Health Subcommittee regarding Population Normative Values for Post-Concussive Computerized Neurocognitive Assessments. In addition, information briefings will be presented on mental health treatment collaboration with the James A. Haley Veterans' Hospital, Sustained Medical and Readiness Training (SMART), medical evaluation boards, an update on the work of the Joint Committee to Create a National Policy to Enhance Survivability from Intentional Mass-Casualty and Active Shooter Events, and medical implications of anti-access/area denial.

Public's Accessibility to the Meeting

Pursuant to 5 U.S.C. 552b, as amended, and 41 CFR 102–3.140 through 102–3.165 and subject to availability of space, this meeting is open to the public. Seating is limited and is on a first-come basis. All members of the public who wish to attend the public meeting must contact Ms. Kendal Brown at the number listed in the section **FOR FURTHER INFORMATION CONTACT** no later than 12:00 p.m. on Friday, October 30, 2015 to register and must provide their driver's license number and social security number to Ms. Brown. Public attendees enter MacDill AFB through the Dale Mabry Gate. Attendees should allow one hour for the security check and travel to meeting location. Additional details will be provided to all registrants.

Special Accommodations

Individuals requiring special accommodations to access the public meeting should contact Ms. Kendal Brown at least five (5) business days prior to the meeting so that appropriate arrangements can be made.

Written Statements

Any member of the public wishing to provide comments to the DHB may do so in accordance with 41 CFR 102–3.105(j) and 102–3.140 and section 10(a)(3) of the Federal Advisory Committee Act, and the procedures described in this notice.

Individuals desiring to provide comments to the DHB may do so by submitting a written statement to the DHB Designated Federal Officer (DFO) (see **FOR FURTHER INFORMATION CONTACT**). Written statements should not be longer than two type-written pages and address the following details: the issue, discussion, and a recommended course of action. Supporting documentation may also be included, as needed, to establish the appropriate historical context and to provide any necessary background information.

If the written statement is not received at least five (5) business days prior to the meeting, the DFO may choose to postpone consideration of the statement until the next open meeting.

The DFO will review all timely submissions with the DHB President and ensure they are provided to members of the DHB before the meeting that is subject to this notice. After reviewing the written comments, the President and the DFO may choose to invite the submitter to orally present their issue during an open portion of this meeting or at a future meeting. The DFO, in consultation with the DHB President, may allot time for members of the public to present their issues for review and discussion by the Defense Health Board.

Dated: October 20, 2015.

Morgan F. Park,

Alternate OSD Federal Register Liaison Officer, Department of Defense.

[FR Doc. 2015–27011 Filed 10–22–15; 8:45 am]

BILLING CODE 5001–06–P

DEPARTMENT OF DEFENSE

Department of the Army, Corps of Engineers

Notice of Intent To Prepare a Draft Environmental Impact Statement for the Sacramento River Flood Control Project, California, General Reevaluation

AGENCY: Department of the Army, U.S. Army Corps of Engineers, DoD.

ACTION: Notice of intent.

SUMMARY: The U.S. Army Corps of Engineers, Sacramento District (Corps), intends to prepare a draft Environmental Impact Statement (DEIS) for the general reevaluation of the Sacramento River Flood Control Project, California. The Corps will serve as the lead agency for compliance with the National Environmental Policy Act (NEPA). The general reevaluation is assessing opportunities to restore ecosystem function along the Sacramento River and improve flood risk reduction capabilities of the flood conveyance system originally constructed in 1917. The system is located along the Sacramento River, from Elder Creek near Tehama to its confluence with the San Joaquin River in the Sacramento-San Joaquin Delta near Collinsville. System features are also located along a number of tributaries, sloughs, and bypass channels, including the Feather River, American River, Sutter Bypass, and Yolo Bypass.

DATES: Written comments regarding the scope of the general reevaluation and DEIS should be received by the Corps on or before November 23, 2015.

ADDRESSES: Send written comments and suggestions concerning this general reevaluation and DEIS to Mr. Dan Artho, U.S. Army Corps of Engineers, Sacramento District, Attn: Planning Division (CESPK–PD), 1325 J Street, Sacramento, CA 95814 or via email at *daniel.f.artho@usace.army.mil.* Requests to be placed on the mailing list should also be sent to this address.

FOR FURTHER INFORMATION CONTACT: Mr. Dan Artho via telephone at (916) 557–7723, email at *daniel.f.artho@usace.army.mil,* or fax at (916) 557–7856. Study information will also be posted periodically on the internet at *http://bit.ly/sacrivergrr.*

SUPPLEMENTARY INFORMATION:

1. *Proposed Action.* The Corps, in cooperation with its non-Federal sponsors (The Central Valley Flood Protection Board and the State of California Department of Water Resources), is reevaluating the Sacramento River Flood Control Project to identify opportunities to restore the function and processes of the Sacramento River's aquatic ecosystem as well as improve the project's flood risk reduction performance. The general reevaluation is authorized pursuant with the Flood Control Act, Public Law 64–367, § 2, 39 Stat. 948 (1917) as amended and modified by subsequent Acts of Congress and as modified by Flood Control Act, Public Law 86–654, § 203, 74 Stat. 498 (1960), as supplemented by the River Basin Monetary Authorization Act, Public Law 93–252, § 202, 88 Stat. 49 (1974), and the Continuing Appropriations Resolution, Public Law 97–377, § 140, 96 Stat. 1916 (1982), and the Water Resources Development Act, Public Law 110–114, § 3031, 121 Stat. 1113 (2007).

2. *Alternatives.* The general reevaluation will assess a combination of one or more ecosystem restoration and flood risk management measures including widening existing bypasses,

modifying existing weirs, optimizing weir operations, constructing setback levees, developing floodplain management plans, restoring riverine aquatic and riparian habitat, removing barriers to fish passage, and restoring natural geomorphic processes, among others. Changes or modifications to the Sacramento River Flood Control Project may include updates or revisions to the operation and maintenance manuals in affected areas. In addition, a no action alternative will be assessed. Mitigation measures for any significant adverse effects on environmental resources will be identified and incorporated into the alternatives in compliance with various Federal and State statutes.

3. *Scoping Process:*

a. Public scoping meetings will be held on November 3rd, 2015, from 3:00 p.m. to 7:00 p.m. at the City of West Sacramento, 1110 W. Capitol Ave., West Sacramento, California 95691, and November 9th, 2015 from 3:00 p.m. to 7:00 p.m. at the Yuba County Board of Supervisors, 915 Eighth Street, Marysville, California 95901. An overview of the study and the NEPA process will be presented, and an opportunity will be afforded to all interested parties to provide comments regarding the scope of the draft general reevaluation and DEIS analysis as well as potential alternatives.

b. Issues that will be analyzed in depth in the DEIS include effects on hydrology and hydraulics, vegetation and wildlife, special-status species, water quality, air quality, socioeconomic conditions, transportation, agricultural resources, hazardous materials, and cultural resources. Other issues may include geology, soils, topography, noise, esthetics, climate and recreation. This is a large geographic extent with many technical, physical, biological, and social complexities associated with it.

c. The Corps will consult with the U.S. Fish and Wildlife Service and the National Marine Fisheries Service to comply with the Endangered Species Act and the Fish and Wildlife Coordination Act. The Corps will also consult with the State Historic Preservation Officer to comply with the National Historic Preservation Act and coordinate with the U.S. Bureau of Indian Affairs to establish consultation requirements with tribes having trust assets and tribal interests that could be affected by the general reevaluation's outcome.

d. A 45-day review period will be allowed for all interested agencies and individuals to review and comment on the DEIS. All interested persons are encouraged to respond to this notice and provide a current address if they wish to be contacted about the DEIS.

4. *Availability.* The DEIS is scheduled to be available for public review and comment in the Spring of 2017.

Dated: October 16, 2015.

Michael J. Farrell,

Colonel, U.S. Army, District Commander.

[FR Doc. 2015–27032 Filed 10–22–15; 8:45 am]

BILLING CODE 3720–58–P

DEPARTMENT OF ENERGY

Meeting; President's Council of Advisors on Science and Technology

AGENCY: Office of Science, Department of Energy.

ACTION: Notice of partially-closed meeting.

SUMMARY: This notice sets forth the schedule and summary agenda for a partially-closed meeting of the President's Council of Advisors on Science and Technology (PCAST), and describes the functions of the Council. The Federal Advisory Committee Act (Pub. L. 92–463, 86 Stat. 770) requires that public notice of these meetings be announced in the **Federal Register**.

DATES: November 20, 2015, 9:00 a.m. to 12:00 p.m.

ADDRESSES: National Academy of Sciences, 2101 Constitution Avenue NW., Washington, DC in the Lecture Room.

FOR FURTHER INFORMATION CONTACT: Information regarding the meeting agenda, time, location, and how to register for the meeting is available on the PCAST Web site at: *http://whitehouse.gov/ostp/pcast.* A live video webcast and an archive of the webcast after the event are expected to be available at *http://whitehouse.gov/ostp/pcast.* The archived video will be available within one week of the meeting. Questions about the meeting should be directed to Ms. Jennifer Michael at *jmichael@ostp.eop.gov,* (202) 395–2121. Please note that public seating for this meeting is limited and is available on a first-come, first-served basis.

SUPPLEMENTARY INFORMATION: The President's Council of Advisors on Science and Technology (PCAST) is an advisory group of the nation's leading scientists and engineers, appointed by the President to augment the science and technology advice available to him from inside the White House, cabinet departments, and other Federal agencies. See the Executive Order at *http://www.whitehouse.gov/ostp/pcast.* PCAST is consulted about and provides analyses and recommendations concerning a wide range of issues where understandings from the domains of science, technology, and innovation may bear on the policy choices before the President. PCAST is co-chaired by Dr. John P. Holdren, Assistant to the President for Science and Technology, and Director, Office of Science and Technology Policy, Executive Office of the President, The White House; and Dr. Eric S. Lander, President, Broad Institute of the Massachusetts Institute of Technology and Harvard.

Type of Meeting: Open and Closed.

Proposed Schedule and Agenda: The President's Council of Advisors on Science and Technology (PCAST) is scheduled to meet in open session on November 20, 2015 from 9:00 a.m. to 12:00 p.m.

Open Portion of Meeting: During this open meeting, PCAST is scheduled to discuss its study on private sector activities for adaptation and resilience to climate change and its letter report on hearing technologies. They will also hear from speakers who will remark on nanotechnology and who will discuss new regulatory frameworks for research. Additional information and the agenda, including any changes that arise, will be posted at the PCAST Web site at: *http://whitehouse.gov/ostp/pcast.*

Closed Portion of the Meeting: PCAST may hold a closed meeting of approximately 1 hour with the President on November 20, 2015, which must take place in the White House for the President's scheduling convenience and to maintain Secret Service protection. This meeting will be closed to the public because such portion of the meeting is likely to disclose matters that are to be kept secret in the interest of national defense or foreign policy under 5 U.S.C. 552b(c)(1).

Public Comments: It is the policy of the PCAST to accept written public comments of any length, and to accommodate oral public comments whenever possible. The PCAST expects that public statements presented at its meetings will not be repetitive of previously submitted oral or written statements.

The public comment period for this meeting will take place on November 20, 2015 at a time specified in the meeting agenda posted on the PCAST Web site at *http://whitehouse.gov/ostp/pcast.* This public comment period is designed only for substantive commentary on PCAST's work, not for business marketing purposes.

Oral Comments: To be considered for the public speaker list at the meeting, interested parties should register to speak at *http://whitehouse.gov/ostp/pcast,* no later than 12:00 p.m. Eastern Time on November 12, 2015. Phone or email reservations will not be accepted. To accommodate as many speakers as possible, the time for public comments will be limited to two (2) minutes per person, with a total public comment period of up to 15 minutes. If more speakers register than there is space available on the agenda, PCAST will randomly select speakers from among those who applied. Those not selected to present oral comments may always file written comments with the committee. Speakers are requested to bring at least 25 copies of their oral comments for distribution to the PCAST members.

Written Comments: Although written comments are accepted continuously, written comments should be submitted to PCAST no later than 12:00 p.m. Eastern Time on November 12, 2015 so that the comments may be made available to the PCAST members prior to this meeting for their consideration. Information regarding how to submit comments and documents to PCAST is available at *http://whitehouse.gov/ostp/pcast* in the section entitled ''Connect with PCAST.''

Please note that because PCAST operates under the provisions of FACA, all public comments and/or presentations will be treated as public documents and will be made available for public inspection, including being posted on the PCAST Web site.

Meeting Accommodations: Individuals requiring special accommodation to access this public meeting should contact Ms. Jennifer Michael at least ten business days prior to the meeting so that appropriate arrangements can be made.

Issued in Washington, DC, on October 19, 2015.

LaTanya R. Butler,

Deputy Committee Management Officer.

[FR Doc. 2015–26998 Filed 10–22–15; 8:45 am]

BILLING CODE 6450–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

Combined Notice of Filings #2

Take notice that the Commission received the following electric corporate filings:

Docket Numbers: EC16–15–000.

Applicants: Michigan Power Limited Partnership.

Description: Application for Authorization Pursuant to Section 203 of the Federal Power Act of Michigan Power Limited Partnership.

Filed Date: 10/19/15.

Accession Number: 20151019–5314.

Comments Due: 5 p.m. ET 11/9/15.

Take notice that the Commission received the following electric rate filings:

Docket Numbers: ER10–2719–023; ER10–2718–024; ER14–1317–005; ER11–2041–009; ER11–2042–009; ER10–3193–008; ER10–2964–010; ER10–2924–008; ER10–2480–007; ER10–2959–008; ER10–2961–008; ER10–2934–007; ER12–281–009; ER10–3099–015; ER13–821–009; ER10–2950–007; ER14–2500–003; ER14–2498–003; ER10–2615–009; ER10–2538–005; ER11–2335–010.

Applicants: East Coast Power Linden Holding, L.L.C., Cogen Technologies Linden Venture, L.P., Sunshine Gas Producers, LLC, Innovative Energy Systems, LLC, Seneca Energy II, LLC, Brooklyn Navy Yard Cogeneration Partners, L.P., Selkirk Cogen Partners, L.P., Kleen Energy Systems, LLC, Berkshire Power Company, LLC, Chambers Cogeneration, Limited Partnership, Edgecombe Genco, LLC, Logan Generating Company, L.P., Northampton Generating Company, L.P., RC Cape May Holdings, LLC, Scrubgrass Generating Company, L.P., Spruance Genco, LLC, Newark Energy Center, LLC, EIF Newark, LLC, Plum Point Energy Associates, LLC, Plum Point Services Company, LLC, Panoche Energy Center, LLC.

Description: Notice of Non-Material Change in Status of East Coast Power Linden Holding, L.L.C., *et al.*

Filed Date: 10/19/15.

Accession Number: 20151019–5252.

Comments Due: 5 p.m. ET 11/9/15.

Docket Numbers: ER15–2236–001.

Applicants: Midwest Power Transmission Arkansas, LLC.

Description: Compliance filing: Compliance Filing, Midwest Power Transmission Arkansas, LLC to be effective 9/21/2015.

Filed Date: 10/19/15.

Accession Number: 20151019–5329.

Comments Due: 5 p.m. ET 11/9/15.

Docket Numbers: ER15–2237–001.

Applicants: Kanstar Transmission, LLC.

Description: Compliance filing: Compliance Filing, Kanstar Transmission, LLC to be effective 9/21/2015.

Filed Date: 10/19/15.

Accession Number: 20151019–5330.

Comments Due: 5 p.m. ET 11/9/15.

Docket Numbers: ER16–117–000.

Applicants: Wolverine Power Supply Cooperative, Inc.

Description: § 205(d) Rate Filing: Oden IFA to be effective 10/2/2015.

Filed Date: 10/19/15.

Accession Number: 20151019–5299.

Comments Due: 5 p.m. ET 11/9/15.

Docket Numbers: ER16–118–000.

Applicants: Midcontinent Independent System Operator, Inc., ALLETE, Inc.

Description: § 205(d) Rate Filing: 2015–10–19_Allete Transmission Rate Incentive Filing to be effective 1/1/2016.

Filed Date: 10/19/15.

Accession Number: 20151019–5300.

Comments Due: 5 p.m. ET 11/9/15.

Docket Numbers: ER16–119–000.

Applicants: PJM Interconnection, L.L.C.

Description: § 205(d) Rate Filing: Original Service Agreement No. 4276; Queue #Y3–088/Y3–090/Y3–091 to be effective 9/18/2015.

Filed Date: 10/19/15.

Accession Number: 20151019–5342.

Comments Due: 5 p.m. ET 11/9/15.

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: October 19, 2015.

Nathaniel J. Davis, Sr.,

Deputy Secretary.

[FR Doc. 2015–26960 Filed 10–22–15; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

Combined Notice of Filings

Take notice that the Commission has received the following Natural Gas Pipeline Rate and Refund Report filings:

Filings Instituting Proceedings

Docket Numbers: RP16–49–000.

Applicants: Centra Pipelines Minnesota Inc.

Description: § 4(d) Rate Filing: Updated Shipper Index Dec 2015 to be effective 12/1/2015.

Filed Date: 10/14/15.

Accession Number: 20151014–5079.

Comments Due: 5 p.m. ET 10/26/15.

Docket Numbers: RP16–50–000.

Applicants: Alliance Pipeline L.P.

Description: § 4(d) Rate Filing: October 15–31 2015 Auction to be effective 10/15/2015.

Filed Date: 10/14/15.

Accession Number: 20151014–5117.

Comments Due: 5 p.m. ET 10/26/15.

Docket Numbers: RP16–51–000.

Applicants: Cadeville Gas Storage LLC.

Description: § 4(d) Rate Filing: Cadeville Gas Storage—August 2015 Tariff Modifications to be effective 8/6/2015.

Filed Date: 10/14/15.

Accession Number: 20151014–5217.

Comments Due: 5 p.m. ET 10/26/15.

Docket Numbers: RP16–52–000.

Applicants: Gulf South Pipeline Company, LP.

Description: § 4(d) Rate Filing: Amendment to Neg Rate Agmt (Encana 37663 Rate Case Amendment-fuel) to be effective 10/15/2015.

Filed Date: 10/15/15.

Accession Number: 20151015–5095.

Comments Due: 5 p.m. ET 10/27/15.

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: October 15, 2015.

Nathaniel J. Davis, Sr.,

Deputy Secretary.

[FR Doc. 2015–26961 Filed 10–22–15; 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: ER10–1577–004.
Applicants: Dogwood Energy LLC.
Description: Notice of Change in Status of Dogwood Energy LLC.
Filed Date: 10/16/15.
Accession Number: 20151016–5491.
Comments Due: 5 p.m. ET 11/6/15.

Docket Numbers: ER15–2693–002.
Applicants: Baltimore Power Company LLC.
Description: Tariff Amendment: Amendment to 2 to be effective 10/30/2015.
Filed Date: 10/16/15.
Accession Number: 20151016–5414.
Comments Due: 5 p.m. ET 11/6/15.

Docket Numbers: ER16–99–000.
Applicants: Florida Power & Light Company.
Description: § 205(d) Rate Filing: FPL and Lee County Electric Cooperative, Inc. Revisions to NITSA No. 266 to be effective 1/1/2016.
Filed Date: 10/16/15.
Accession Number: 20151016–5374.
Comments Due: 5 p.m. ET 11/6/15.

Docket Numbers: ER16–100–000.
Applicants: Windom Transmission, LLC.
Description: § 205(d) Rate Filing: Windom Transmission and HyperGen Transmission and Interconnection Agreement to be effective 12/15/2015.
Filed Date: 10/16/15.
Accession Number: 20151016–5375.
Comments Due: 5 p.m. ET 11/6/15.

Docket Numbers: ER16–101–000.
Applicants: Windom Transmission, LLC.
Description: § 205(d) Rate Filing: Windom Transmission and JMC Wind Transmission and Interconnection Agreement to be effective 12/15/2015.
Filed Date: 10/16/15.
Accession Number: 20151016–5376.
Comments Due: 5 p.m. ET 11/6/15.

Docket Numbers: ER16–102–000.
Applicants: Windom Transmission, LLC.
Description: § 205(d) Rate Filing: Windom Transmission and LimiEnergy Transmission and Interconnection Agreement to be effective 12/15/2015.
Filed Date: 10/16/15.
Accession Number: 20151016–5378.
Comments Due: 5 p.m. ET 11/6/15.

Docket Numbers: ER16–103–000.
Applicants: Windom Transmission, LLC.
Description: § 205(d) Rate Filing: Windom Transmission and Maiden Winds Transmission and Interconnection Agreement to be effective 12/15/2015.
Filed Date: 10/16/15.
Accession Number: 20151016–5381.
Comments Due: 5 p.m. ET 11/6/15.

Docket Numbers: ER16–104–000.
Applicants: Windom Transmission, LLC.
Description: § 205(d) Rate Filing: Windom Transmission and MD&E Transmission and Interconnection Agreement to be effective 12/15/2015.
Filed Date: 10/16/15.
Accession Number: 20151016–5385.
Comments Due: 5 p.m. ET 11/6/15.

Docket Numbers: ER16–105–000.
Applicants: Windom Transmission, LLC.
Description: § 205(d) Rate Filing: Windom Transmission and Power Beyond Transmission and Interconnection Agreement to be effective 12/15/2015.
Filed Date: 10/16/15.
Accession Number: 20151016–5388.
Comments Due: 5 p.m. ET 11/6/15.

Docket Numbers: ER16–106–000.
Applicants: Windom Transmission, LLC.
Description: § 205(d) Rate Filing: Windom Transmission and Power Blades Transmission and Interconnection Agreement to be effective 12/15/2015.
Filed Date: 10/16/15.
Accession Number: 20151016–5390.
Comments Due: 5 p.m. ET 11/6/15.

Docket Numbers: ER16–107–000.
Applicants: Windom Transmission, LLC.
Description: § 205(d) Rate Filing: Windom Transmission and Stony Hills Transmission and Interconnection Agreement to be effective 12/15/2015.
Filed Date: 10/16/15.
Accession Number: 20151016–5396.
Comments Due: 5 p.m. ET 11/6/15.

Docket Numbers: ER16–108–000.
Applicants: Windom Transmission, LLC.
Description: § 205(d) Rate Filing: Windom Transmission and Tower of Power Transmission & Interconnection Agreement to be effective 12/15/2015.
Filed Date: 10/16/15.
Accession Number: 20151016–5403.
Comments Due: 5 p.m. ET 11/6/15.

Docket Numbers: ER16–109–000.
Applicants: Windom Transmission, LLC.
Description: § 205(d) Rate Filing: Windom Transmission and Whispering Wind Transmission & Interconnection Agreement to be effective 12/15/2015.

Filed Date: 10/16/15.
Accession Number: 20151016–5405.
Comments Due: 5 p.m. ET 11/6/15.

Docket Numbers: ER16–110–000.
Applicants: Windom Transmission, LLC.
Description: § 205(d) Rate Filing: Windom Transmission and White Caps Interconnection and Transmission Agreement to be effective 12/15/2015.
Filed Date: 10/16/15.
Accession Number: 20151016–5407.
Comments Due: 5 p.m. ET 11/6/15.

Docket Numbers: ER16–111–000.
Applicants: Puget Sound Energy, Inc.
Description: § 205(d) Rate Filing: Vantage Long Term P–T–P Service Agreement to be effective 10/1/2015.
Filed Date: 10/16/15.
Accession Number: 20151016–5452.
Comments Due: 5 p.m. ET 11/6/15.

Docket Numbers: ER16–112–000.
Applicants: Puget Sound Energy, Inc.
Description: Initial rate filing: Kittitas NITSA SA No. 796 and NOA SA No. 797 to be effective 9/1/2015.
Filed Date: 10/16/15.
Accession Number: 20151016–5460.
Comments Due: 5 p.m. ET 11/6/15.

Docket Numbers: ER16–113–000.
Applicants: PJM Interconnection, L.L.C.
Description: § 205(d) Rate Filing: First Revised Service Agreement No. 3990; Queue W1–130 (WMPA) to be effective 9/30/2015.
Filed Date: 10/19/15.
Accession Number: 20151019–5203.
Comments Due: 5 p.m. ET 11/9/15.

Docket Numbers: ER16–114–000.
Applicants: Midcontinent Independent System Operator, Inc., Ameren Illinois Company.
Description: § 205(d) Rate Filing: 2015–10–19_SA 1975 Ameren-Norris 4th Rev WDS Agreement to be effective 10/1/2015.
Filed Date: 10/19/15.
Accession Number: 20151019–5215.
Comments Due: 5 p.m. ET 11/9/15.

Docket Numbers: ER16–115–000.
Applicants: PJM Interconnection, L.L.C.
Description: § 205(d) Rate Filing: 3rd Quarter 2015 Update to OA/RAA Member Lists to be effective 9/30/2015.
Filed Date: 10/19/15.
Accession Number: 20151019–5243.
Comments Due: 5 p.m. ET 11/9/15.

Docket Numbers: ER16–116–000.
Applicants: ISO New England Inc., Eversource Energy Service Company.
Description: § 205(d) Rate Filing: Eversource Energy Service Company—Attachment F to be effective 4/16/2015.
Filed Date: 10/19/15.
Accession Number: 20151019–5244.
Comments Due: 5 p.m. ET 11/9/15.

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: October 19, 2015.

Nathaniel J. Davis, Sr.,

Deputy Secretary.

[FR Doc. 2015–26959 Filed 10–22–15; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. AD06–6–000]

Joint Meeting of the Nuclear Regulatory Commission and the Federal Energy Regulatory Commission; Notice of Joint Meeting of the Federal Energy Regulatory Commission and the Nuclear Regulatory Commission

The Federal Energy Regulatory Commission (FERC) and the Nuclear Regulatory Commission (NRC) will hold a joint meeting on Wednesday, October 21, 2015 at the headquarters of the Federal Energy Regulatory Commission, 888 First Street NE., Washington, DC 20426. The meeting is expected to begin at 9:00 a.m. and conclude at approximately 11:30 a.m. Eastern Time. Members of the public may attend the open session. Commissioners from both agencies are expected to participate.

The format for the joint meeting will consist of discussions between the two sets of Commissioners following presentations by their respective staffs. In addition, representatives of the North American Electric Reliability Corporation (NERC) will attend and participate in this meeting.

The technical conference will be transcribed. Transcripts of the technical conference will be available for a fee from Ace-Federal Reporters, Inc. (202) 347–3700. There will be a free webcast of the conference. The webcast will allow persons to listen to the technical conference, but not participate. Anyone with Internet access can listen to the conference by navigating to the Calendar of Events at *www.ferc.gov* and locating the technical conference in the Calendar. The technical conference will contain a link to its webcast. The Capital Connection provides technical support for the webcast and offers the option of listing to the meeting via phone-bridge for a fee. If you have any questions, please visit *www.CapitolConnection.org* or call 703–993–3100.[1]

Pre-registration is not required but is highly encouraged for those attending in person. Attendees may register in advance at the following Web page: *https://www.ferc.gov/whats-new/registration/10-21-15-NRC-form.asp.* Attendees should bring a photo ID and allow time to pass through building security procedures. There is no fee to attend the open meeting.

Commission conferences are accessible under section 508 of the Rehabilitation Act of 1973. For accessibility accommodations please send an email to *accessibility@ferc.gov* or call toll free 1–866–208–3372 (voice) or 202–502 -8659 (TTY); or send a fax to 202–208–2106 with the required accommodations.

Questions about the meeting should be directed to Sarah McKinley at *sarah.mckinley@ferc.gov* or by phone at 202–502–8368.

Dated: October 16, 2015.

Kimberly D. Bose,

Secretary.

[FR Doc. 2015–26898 Filed 10–22–15; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. CP16–1–000]

Dominion Transmission, Inc.; Notice of Application

Take notice that on October 1, 2015, Dominion Transmission, Inc. (DTI) 120 Tredegar Street, Richmond, VA, filed an application pursuant to section 7(b) of the Natural Gas Act (NGA) and the Federal Energy Regulatory Commission's (Commission) regulations seeking authorization to: (1) Abandon

[1] The webcast will continue to be available on the Calendar of Events on the Commission's Web site *www.ferc.gov* for three months after the conference.

by sale its gathering and products extraction facilities to Dominion Gathering & Processing, Inc. (DGP) located within the states of West Virginia and Pennsylvania; and (2) refunctionalize certain compression facilities at a processing plant located in Lewis County, West Virginia to gathering and include the compression facilities in the abandonment by sale to DGP, all as more fully described 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, contact FERC at *FERCOnlineSupport@ferc.gov* or call toll-free, (866) 208–3676 or TTY, (202) 502–8659.

Any questions regarding this application should be directed Machelle F. Grim, Dominion Resources Services, Inc., 701 East Cary Street, Richmond, VA 23219, or call (804) 771–3805, or fax (804) 771–4804, or by email: *Machelle.F.Grim@dom.com.*

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.

There are two ways to become involved in the Commission's review of this project. First, any person wishing to obtain legal status by becoming a party to the proceedings for this project should, on or before the comment date stated below file with the Federal Energy Regulatory Commission, 888 First Street NE., Washington, DC 20426, a motion to intervene in accordance with the requirements of the Commission's Rules of Practice and Procedure (18 CFR 385.214 or 385.211) and the Regulations under the NGA (18 CFR 157.10). A person obtaining party status will be placed on the service list maintained by the Secretary of the Commission and will receive copies of all documents filed by the applicant and by all other parties. A party must submit 7 copies of filings made in the proceeding with the Commission and must mail a copy to the applicant and to every other party. Only parties to the proceeding can ask for court review of Commission orders in the proceeding.

However, a person does not have to intervene in order to have comments considered. The second way to participate is by filing with the Secretary of the Commission, as soon as possible, an original and two copies of comments in support of or in opposition to this project. The Commission will consider these comments in determining the appropriate action to be taken, but the filing of a comment alone will not serve to make the filer a party to the proceeding. The Commission's rules require that persons filing comments in opposition to the project provide copies of their protests only to the party or parties directly involved in the protest.

Persons who wish to comment only on the environmental review of this project should submit an original and two copies of their comments to the Secretary of the Commission. Environmental commentors will be placed on the Commission's environmental mailing list, will receive copies of the environmental documents, and will be notified of meetings associated with the Commission's environmental review process. Environmental commentors will not be required to serve copies of filed documents on all other parties. However, the non-party commentors will not receive copies of all documents filed by other parties or issued by the Commission (except for the mailing of environmental documents issued by the Commission) and will not have the right to seek court review of the Commission's final order.

The Commission strongly encourages electronic filings of comments, protests and interventions 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.

Comment Date: 5:00 p.m. Eastern Time on November 6, 2015.

Dated: October 16, 2015.

Kimberly D. Bose,

Secretary.

[FR Doc. 2015–26899 Filed 10–22–15; 8:45 am]

BILLING CODE 6717–01–P

ENVIRONMENTAL PROTECTION AGENCY

[ER–FRL–9023–6]

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 (EISs).

Filed 10/12/2015 Through 10/16/2015.

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-nepa-public/action/eis/search.*

EIS No. 20150291, Draft, NMFS, FL, Regulatory Amendment 16 to the Fishery Management Plan for the Snapper-Grouper Fishery of the South Atlantic Region, Comment Period Ends: 12/07/2015, Contact: Rick DeVictor 727–551–5720.

EIS No. 20150292, Final, HUD, CA, Potrero HOPE SF Master Plan, Review Period Ends: 11/23/2015, Contact: Eugene Flannery 415–701–5598.

EIS No. 20150293, Final, USFS, AK, Saddle Lakes Timber Sale, Review Period Ends: 12/07/2015, Contact: Daryl Bingham 907–228–4114.

EIS No. 20150294, Draft, FHWA, NC, I–26 Asheville Connector, Comment Period Ends: 12/07/2015, Contact: John F. Sullivan, III 919–856–4346 ext. 122.

Dated: October 20, 2015.

Karin Leff

Acting Director, NEPA Compliance Division, Office of Federal Activities.

[FR Doc. 2015–27054 Filed 10–22–15; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

[EPA–HQ–OPPT–2015–0503; FRL–9934–96]

Certain New Chemicals; Receipt and Status Information for August 2015

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice.

SUMMARY: EPA is required under the Toxic Substances Control Act (TSCA) to publish in the **Federal Register** a notice of receipt of a premanufacture notice (PMN); an application for a test marketing exemption (TME), both pending and/or expired; and a periodic status report on any new chemicals under EPA review and the receipt of notices of commencement (NOC) to manufacture those chemicals. This document covers the period from August 1, 2015 to August 31, 2015.

DATES: Comments identified by the specific PMN number or TME number, must be received on or before November 23, 2015.

ADDRESSES: Submit your comments, identified by docket identification (ID) number EPA–HQ–OPPT–2015–0183, and the specific PMN number or TME number for the chemical related to your comment, 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 Confidential Business Information (CBI) or other information whose disclosure is restricted by statute.
- *Mail:* Document Control Office (7407M), Office of Pollution Prevention and Toxics (OPPT), Environmental Protection Agency, 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.*

FOR FURTHER INFORMATION CONTACT:

For technical information contact: Jim Rahai, IMD (7407M), Office of Pollution Prevention and Toxics, Environmental Protection Agency, 1200 Pennsylvania Ave. NW., Washington, DC 20460–0001; telephone number: 202–564–8593; email address: *Rahai.jim@epa.gov.*

For general information contact: The TSCA-Hotline, ABVI-Goodwill, 422 South Clinton Ave., Rochester, NY 14620; telephone number: (202) 554–1404; email address: *TSCA-Hotline@epa.gov.*

SUPPLEMENTARY INFORMATION:

I. General Information

A. Does this action apply to me?

This action is directed to the public in general. As such, the Agency has not attempted to describe the specific entities that this action may apply. Although others may be affected, this action applies directly to the submitter of the PMNs addressed in this action.

B. What should I consider as I prepare my comments for EPA?

1. *Submitting CBI.* Do not submit this information to 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 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.

2. *Tips for preparing your comments.* When preparing and submitting your comments, see the commenting tips at *http://www.epa.gov/dockets/comments.html.*

II. What action is the agency taking?

This document provides receipt and status reports, which cover the period from August 2, 2015 to August 31, 2015, and consists of the PMNs and TMEs both pending and/or expired, and the NOCs to manufacture a new chemical that the Agency has received under TSCA section 5 during this time period.

III. What is the agency's authority for taking this action?

Under TSCA, 15 U.S.C. 2601 *et seq.,* EPA classifies a chemical substance as either an ''existing'' chemical or a ''new'' chemical. Any chemical substance that is not on EPA's, TSCA Inventory is classified as a ''new chemical,'' while those that are on the TSCA Inventory are classified as an ''existing chemical.'' For more information about the TSCA Inventory go to: *http://www.epa.gov/opptintr/newchems/pubs/inventory.htm.*

Anyone who plans to manufacture or import a new chemical substance for a non-exempt commercial purpose is required by TSCA section 5 to provide EPA with a PMN before initiating the activity. Section 5(h)(1) of TSCA authorizes EPA to allow persons, upon application, to manufacture (includes import) or process a new chemical substance, or a chemical substance subject to a significant new use rule (SNUR) issued under TSCA section 5(a), for ''test marketing'' purposes, which is referred to as a test marketing exemption, or TME. For more information about the requirements applicable to a new chemical go to: *http://www.epa.gov/oppt/newchems.*

Under TSCA sections 5(d)(2) and 5(d)(3), EPA is required to publish in the **Federal Register** a notice of receipt of a PMN or an application for a TME and to publish in the **Federal Register** periodic status reports on the new chemicals under review and the receipt of NOCs to manufacture those chemicals.

IV. Receipt and Status Reports

As used in each of the tables, (S) indicates that the information in the table is the specific information provided by the submitter, and (G) indicates that the information in the table is generic information because the specific information provided by the submitter was claimed as CBI.

For the PMNs received by EPA during this period, Table 1 provides the following information (to the extent that such information is not claimed as CBI). The EPA case number assigned to the PMN, the date the PMN was received by EPA, the projected end date for EPA's review of the PMN, the submitting manufacturer/importer, the potential uses identified by the manufacturer/importer in the PMN, and the chemical identity.

TABLE 1—STATUS OF THE 45 PMNS RECEIVED FROM AUGUST 1, 2015 TO AUGUST 31, 2015

Case No.	Received date	Projected end date for EPA review	Manufacturer importer	Use	Chemical
P–15–0666	8/4/2015	11/2/2015	CBI	(G) Epoxy hardener	(G) Formaldehyde, polymer with aromatic diamine, 2-(chloromethyl)oxirane and phenol.
P–15–0667	8/4/2015	11/2/2015	Fritz industries, Inc	(S) Oil field additive	(S) Poly[oxy(methyl-1,2-ethanediyl)], alpha-[2-[bis(phosphonomethyl) amino]methylethyl]-omega-[2-[bis (phosphonomethyl)amino]methylethoxy]-, sodium salt (1:4).
P–15–0669	8/4/2015	11/2/2015	CBI	(S) Agricultural iron micronutrient.	(G) Glycine, n,n′-alkyldiylbis-, reaction products with formaldehyde, iron chloride (fecl3) and phenol, potassium salts.
P–15–0670	8/4/2015	11/2/2015	CBI	(G) Fluid Stabilizer	(S) 1,6-Hexanediamine, acetate (1:2).
P–15–0670	8/4/2015	11/2/2015	CBI	(G) Fluid Stabilizer	(S) Ethanol, 2-[(2-aminoethyl)amino]-, acetate (1:2).
P–15–0670	8/4/2015	11/2/2015	CBI	(G) Fluid Stabilizer	(S) 1,2-Cyclohexanediamine, acetate (1:2).
P–15–0670	8/4/2015	11/2/2015	CBI	(G) Fluid Stabilizer	(S) 1,2-Ethanediamine, n1-(2-aminoethyl)-, acetate (1:3).
P–15–0670	8/4/2015	11/2/2015	CBI	(G) Fluid Stabilizer	(S) 1,2-Ethanediamine, n1,n2-bis(2-aminoethyl)-, acetate (1:4).
P–15–0671	8/5/2015	11/3/2015	Tri-State Asphalt, LLC	(S) Emulsifying agent used in the production of asphalt emulsions for “chipsealing” and other road maintenance techniques.	(S) 9-Octadecen-1-amine, hydrochloride (1:1), (9Z).
P–15–0672	8/5/2015	11/3/2015	CBI	(S) Filtration Media (not for drinking water).	(G) Carbon Nanotube.
P–15–0673	8/6/2015	11/4/2015	CBI	(S) Modified urethane polymer used as a deflocculating and dispersing additive in industrial paints and coatings.	(G) Modified Urethane Polymer.
P–15–0674	8/6/2015	11/4/2015	Cardolite Corporation	(G) Cashew nutshell liquid based, epoxy hardener for Higher solids epoxy formulations.	(G) Cashew nutshell liquid polymner with formaldehyde and amine.
P–15–0675	8/7/2015	11/5/2015	CBI	(G) Reactive polyol in automotive coatings application.	(G) Carbamate ester.
P–15–0676	8/7/2015	11/5/2015	CBI	(G) Reactive polyol in automotive coatings application.	(G) Carbamate ester.
P–15–0678	8/10/2015	11/8/2015	CBI	(G) Industrial paper additive.	(G) Metal salt of mineral acid, reaction products with alumina, aluminum hydroxide, aluminum hydroxide oxide (al(oh)o), silica, titanium oxide (tio2) and 3-(triethoxysilyl)-1-propanamine.

TABLE 1—STATUS OF THE 45 PMNS RECEIVED FROM AUGUST 1, 2015 TO AUGUST 31, 2015—Continued

Case No.	Received date	Projected end date for EPA review	Manufacturer importer	Use	Chemical
P–15–0679	8/10/2015	11/8/2015	CBI	(G) Industrial paper additive.	(G) Metal salt of mineral acid, reaction products with alumina, aluminum hydroxide, aluminum hydroxide oxide (al(oh)o), silica, titanium oxide (tio2) and 3-(triethoxysilyl)-n-[3-(triethoxysilyl)propyl]-1-propanamine.
P–15–0680	8/10/2015	11/8/2015	CBI	(G) Ingredient in liquid paint coating.	(G) Propenoic acid, alkyl ester, polymer with 1,3-cyclohexanedialkylamine, reaction products with oxirane(alkoxyalkyl).
P–15–0681	8/11/2015	11/9/2015	CBI	(S) Modified urethane polymer used as a deflocculating and dispersing additive in industrial coatings.	(G)Modified Urethane Polymer.
P–15–0682	8/11/2015	11/9/2015	CBI	(G) Fluid loss control additive.	(G) Acrylic-humic acid-based polymer.
P–15–0683	8/11/2015	11/9/2015	CBI	(G) Demulsifier	(G) Silylated polyether.
P–15–0684	8/12/2015	11/10/2015	Allnex USA Inc	(S) Protective general industrial metal coating resin.	(G) Substituted alkenoic acid, alkyl ester, telomer with alkanethiol and oxiranylalkyl alkyl-alkenoatenoate.
P–15–0686	8/12/2015	11/10/2015	Eden Innovations LLC	(G) Part C: As a concrete admixture, the liquid product containing Part C is mixed with cement, rock aggregates, water and other additives at a concrete mixing plant, usually for delivery by truck to a construction site. Future potential use as an additive for polymers and/or coatings.	(G) Future potential use as an additive for polymers and/or coatings. (G) Part C.
P–15–0687	8/12/2015	11/10/2015	CBI	(G) Adhesive for open non-descriptive use.	(G) Polyester adduct.
P–15–0688	8/13/2015	11/11/2015	CBI	(G) Ingredient for consumer products; dispersive use.	(S) Ethyl tetrahydrofuran-2-carboxylate.
P–15–0689	8/17/2015	11/15/2015	CBI	(S) Chemical Intermediate.	(G) Vegetable Fatty Acid Alkyl Ester.
P–15–0690	8/17/2015	11/15/2015	CBI	(S) Chemical Intermediate.	(G) Vegetable Fatty Acid Alkyl Ester.
P–15–0691	8/17/2015	11/15/2015	CBI	(G) Polymer backbone for further processing.	(G) Polyaminoamide.
P–15–0692	8/17/2015	11/15/2015	CBI	(G) Open non-dispersive use; dispersive use.	(G) Fatty acid esters with polyol.
P–15–0693	8/17/2015	11/15/2015	CBI	(G) Sheet moulding additive.	(G) 1,2-Ethanediamine, n1-(2-aminoethyl)-, reaction products with polyethylenimine and polypropylene alkyol ethers.
P–15–0694	8/18/2015	11/16/2015	CBI	(G) Epoxy Hardener	(G) Phenol, polymer with formaldehyde, glycidyl ether, polymers with aromatic diamine, reaction products with (alkoxymethyl)oxirane.

TABLE 1—STATUS OF THE 45 PMNS RECEIVED FROM AUGUST 1, 2015 TO AUGUST 31, 2015—Continued

Case No.	Received date	Projected end date for EPA review	Manufacturer importer	Use	Chemical
P–15–0695	8/18/2015	11/16/2015	CBI	(G) Additive in oil and gas production.	(G) Cocoamidoamine, methanesulfonates.
P–15–0696	8/19/2015	11/17/2015	CBI	(G) Crosslinker for coatings.	(G) Urethane Acrylate.
P–15–0697	8/19/2015	11/17/2015	CBI	(S) Boron-free, ferrous corrosion inhibitor for water-based metalworking fluids.	(G) Alkyl alkylenetriamine compd. with alkanol ethoxylate phosphate.
P–15–0698	8/20/2015	11/18/2015	CBI	(S) Binder polymer for industrial coatings (focus: metal protection).	(G) Polymer of Aliphatic dicarboxylic acid, Alkanediol and Cycloaliphatic diol.
P–15–0700	8/20/2015	11/18/2015	Bostik, Inc	(G) Adhesive	(G) Long chain oil, pre polymer with Methylenebis [isocyanatobenzene], oxepanone and hydroxy terminated triol.
P–15–0702	8/26/2015	11/24/2015	CBI	(G) Additive, open, non-dispersive use.	(G) Modified polyethyleneglycol diacrylate salt with acidic polyethylene ester.
P–15–0704	8/26/2015	11/24/2015	Gelest	(S) Formation of specialty silicone Elastomers; research.	(S) Siloxanes and silicones, di-me, [(butylethenylmethylsilyl)oxy]- and hydrogen-terminated.
P–15–0705	8/26/2015	11/24/2015	CBI	(S) Alkylarylamine used as an additive and octane booster in aviation fuels.	(G) Alkylarylamine.
P–15–0706	8/27/2015	11/25/2015	CBI	(G) Ingredient for multipurpose exterior coatings.	(G) Mixture of aliphatic N-alkyl ureas containing substituted cyclohexyl and terminal alkoxysilane groups.
P–15–0707	8/27/2015	11/25/2015	CBI	(G) Ingredient for multipurpose exterior coatings.	(G) Mixture of aliphatic N-alkyl ureas containing aspartic ester and terminal alkoxysilane groups.
P–15–0708	8/28/2015	11/26/2015	CBI	(S) Production moisture curing PU hot melts (adhesive).	(G) Polyester Polymer of Aliphatic dicarboxylic acid, Alkanediol and Polyethylen glycol methylphosphonate.
P–15–0709	8/28/2015	11/26/2015	CBI	(S) Cement particle dispersant in concrete mixtures.	(G) Carboxylic acid polymer with sodium phosphinate ester with a-methyl- w-hydroxypoly (oxy-1,2-ethanediyl).
P–15–0710	8/28/2015	11/26/2015	CBI	(S) Cement particle dispersant in concrete mixtures.	(G) Carboxylic acid polymer ester with a-methyl-w-hydroxypoly (oxy-1,2-ethanediyl).
P–15–0711	8/29/2015	11/27/2015	CBI	(G) Organic light-emitting diode material.	(G) Amine-alkyl-polyaromatic hydrocarbon polymer.
P–15–0712	8/31/2015	11/29/2015	CBI	(G) Material for highly dispersive use in consumer products.	(G) Disubstituted cycloalkanol.

For the TMEs received by EPA during this period, Table 2 provides the following information (to the extent that such information is not claimed as CBI). The EPA case number assigned to the TME, the date the TME was received by EPA, the projected end date for EPA's review of the TME, the submitting manufacturer/importer, the potential uses identified by the manufacturer/importer in the TME, and the chemical identity.

TABLE 2—STATUS OF THE 2 TMES RECEIVED FROM AUGUST 1, 2015 TO AUGUST 31, 2015

Case No.	Received date	Projected end date for EPA review	Manufacturer importer	Use	Chemical
T–15–0015	8/17/2015	10/1/2015	CBI	(S) Chemical Intermediate	(G) Vegetable Fatty Acid Alkyl Ester.
T–15–0016	8/17/2015	10/1/2015	CBI	(S) Chemical Intermediate	(G) Vegetable Fatty Acid Alkyl Ester.

For the NOCs received by EPA during this period, Table 3 provides the following information (to the extent that such information is not claimed as CBI). The EPA case number assigned to the NOC, the date the NOC was received by EPA, the projected end date for EPA's review of the NOC, and chemical identity.

TABLE 3—STATUS OF THE 42 NOCS RECEIVED FROM AUGUST 1, 2015 TO AUGUST 31, 2015

Case No.	Received date	Commencement date	Chemical
P–10–0237	8/31/2015	8/21/2015	(S) 2-Propenenitrile polymer with 1,1′-[oxybis(2,1-ethanediyloxy)]bis[ethene], sapond., sodium salts.
P–12–0480	8/4/2015	7/15/2015	(G) Alkyl maleimide substituted bicyclic olefin.
P–13–0180	8/5/2015	6/1/2015	(G) Fatty acid amide.
P–13–0181	8/5/2015	6/1/2015	(G) Fatty acid amide.
P–13–0595	8/17/2015	7/28/2015	(G) Oxirane, alkyl-, polymer with oxirane, hydrogen sulfate, alkyl ethers, alkali metal salts.
P–13–0863	8/4/2015	7/24/2015	(G) Polyamic acid.
J–14–0012	8/17/2015	3/4/2015	(S) Trichoderma reesei for cellulose conversion.
J–14–0014	8/17/2015	2/19/2015	(S) Trichoderma reesei for cellulose conversion.
J–14–0015	8/17/2015	2/25/2015	(S) Trichoderma reesei for cellulose conversion.
P–14–0128	8/20/2015	8/1/2015	(G) Alkyl methacrylate polymer with alkyl acrylate, bis(2,3-heteromonocyclicalkoxy) -2,2-dialkylpropane, vinyl aromatic, propenoic acid esters with c12-14-alkyloxy 1,2 alkyldiol, amine salts.
P–14–0132	8/31/2015	8/31/2015	(S) Alkanes, c8-11-branched and linear.
P–14–0133	8/31/2015	8/31/2015	(S) Alkanes, c9-12-branched and linear.
P–14–0134	8/31/2015	8/31/2015	(S) Alkanes, c9-13 branched and linear.
P–14–0135	8/31/2015	8/31/2015	(S) Alkanes, c10-13-branched and linear.
P–14–0397	8/17/2015	8/6/2015	(S) Benzenepropanol, 1-benzoate.
P–14–0621	8/3/2015	7/13/2015	(G) Alkanedioic anhydride, polymer with alkanediol and branched alcohol.
P–14–0817	8/11/2015	8/3/2015	(S) 3-Hexenoic acid, cyclopropylmethyl ester.
J–15–0003	8/17/2015	6/11/2015	(S) Trichoderma reesei for cellulose conversion.
J–15–0004	8/17/2015	6/6/2015	(S) Trichoderma reesei for cellulose conversion.
J–15–0005	8/17/2015	6/3/2015	(S) Trichoderma reesei for cellulose conversion.
J–15–0019	8/16/2015	7/22/2015	(G) Organic acid producing organism.
P–15–0033	8/27/2015	8/10/2015	(G) Alkyl and aryl-substituted polysiloxane.
P–15–0111	8/7/2015	8/4/2015	(G) Fatty acids, tall-oil, reaction products with an ether and triethylenetetramine.
P–15–0166	8/7/2015	7/22/2015	(G) Aromatic polyester resin.
P–15–0271	8/4/2015	7/28/2015	(G) Urethane resin.
P–15–0274	8/7/2015	7/22/2015	(G) Substituted polystyrene.
P–15–0283	8/25/2015	8/5/2015	(S) Carbamic acid, n-octadecyl-,c,c'-[2,2-dimethyl-1-(1-methylethyl)-1,3-propanediyl]ester.
P–15–0290	8/27/2015	8/24/2015	(G) 2-Oxepanone, polymer with 2,diisocyanato and alkyl ester imidazole-alkyamine-blocked.
P–15–0318	8/14/2015	8/11/2015	(S) Benzene, 1,1′-(2,4-cyclopentadien-1-ylidenemethylene)bis-.
P–15–0354	8/12/2015	7/15/2015	(G) Perfluoropolyether-block-polytetrafluoroethylene.
P–15–0356	8/11/2015	8/11/2015	(S) 2-Propanol, 1,3-bis[4-[1-[4-[1-methyl-1-[4-(2-oxiranylmethoxy)phenyl]ethyl]phenyl]-1-[4-(2-oxiranylmethoxy)phenyl]ethyl]phenoxy]-.
P–15–0356	8/11/2015	8/11/2015	(S) Oxirane, 2,2′-[[1-[4-[1-methyl-1-[4-(2-oxiranylmethoxy)phenyl]ethyl]phenyl]ethylidene]bis(4,1-phenyleneoxymethylene)]bis-.
P–15–0358	8/20/2015	8/6/2015	(G) Oxepanone, polymers with 1,6-diisocyanatohexane trimer and 2-Hydroxyethyl acrylate.
P–15–0367	8/6/2015	8/5/2015	(G) Cycloalkanediamine, polymer with 2,2′-[methylenebis(phenyleneoxymethylene)]bis[oxirane].
P–15–0374	8/26/2015	8/17/2015	(G) Methacrylic copolymer with cyclic structure unit.
P–15–0378	8/31/2015	8/31/2015	(G) Disubstituted, homopolymer, alkanoic acid-polyalkylene glycol ether with substituted alkane (3:1) reaction products-blocked.
P–15–0385	8/19/2015	7/20/2015	(G) Hydrogenated oil.
P–15–0416	8/21/2015	7/30/2015	(G) Aromatic isocyanate, polymer with aromatic diamine, alkyloxirane, alkyloxirane polymer with oxirane ether with alkyltriol (3:1), and oxirane.
P–15–0423	8/14/2015	7/24/2015	(G) Polyurethane, (meth)acrylate blocked.
P–15–0460	8/20/2015	8/19/2015	(G) Substituted alkanoic acid-, metal salt.
P–15–0461	8/24/2015	8/16/2015	(G) Siloxanes and silicones, alkoxy me, polymers with me silsesquioxanes, alkoxy-terminated.

Authority: 15 U.S.C. 2601 *et seq.*

Dated: October 15, 2015.

Pamela S. Myrick,

Director, Information Management Division, Office of Pollution Prevention and Toxics.

[FR Doc. 2015–27031 Filed 10–22–15; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

[EPA–HQ–OPP–2015–0651; FRL–9934–39]

Pesticide Program Dialogue Committee; Notice of Charter Renewal

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice.

SUMMARY: Notice is hereby given that the Environmental Protection Agency has determined that, in accordance with the provisions of the Federal Advisory Committee Act (FACA), 5 U.S.C. App.2., the Pesticide Program Dialogue Committee (PPDC) is a necessary committee which is in the public interest. Accordingly, PPDC will be renewed for an additional two-year period. The purpose of PPDC is to provide advice and recommendations to the EPA Administrator on issues associated with regulatory development and reform initiatives, evolving public policy and program implementation issues, and science issues associated with evaluating and reducing risks from use of pesticides.

FOR FURTHER INFORMATION CONTACT: Dea Zimmerman, Designated Federal Officer, Pesticide Program Dialogue Committee (PPDC), U.S. EPA, (mail code LC–8J), 77 W. Jackson Boulevard, Chicago, IL 60604, telephone number: (312) 353–6344; email address: *zimmerman.dea@epa.gov*.

SUPPLEMENTARY INFORMATION:

A. Does this action apply to me?

You may be potentially affected by this action if you work in in agricultural settings or if you are concerned about implementation of the Federal Insecticide, Fungicide, and Rodenticide Act (FIFRA); the Federal Food, Drug, and Cosmetic Act (FFDCA); and the amendments to both of these major pesticide laws by the Food Quality Protection Act (FQPA) of 1996; the Pesticide Registration Improvement Act, and the Endangered Species Act. Potentially affected entities may include, but are not limited to: Agricultural workers and farmers; pesticide industry and trade associations; environmental, consumer, and farm worker groups; pesticide users and growers; animal rights groups; pest consultants; State, local, and tribal governments; academia; public health organizations; and the public. If you have questions regarding the applicability of this action to a particular entity, consult the person listed under **FOR FURTHER INFORMATION CONTACT**.

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–2015–0651, 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*.

Authority: 5 U.S.C. App.2.

Dated: October 13, 2015.

Jack Housenger,

Director, Office of Pesticide Programs.

[FR Doc. 2015–26769 Filed 10–22–15; 8:45 am]

BILLING CODE 6560–50–P

FEDERAL MARITIME COMMISSION

[Petition No. P5–15]

Petition of Pacific International Lines and Mariana Express Lines for an Exemption From Commission Regulations; Notice of Filing and Request for Comments

This is to provide notice of filing and to invite comments on or before November 13, 2015, with regard to the Petition described below.

Pacific International Lines (Private) Limited (PIL) and Mariana Express Lines Pte. Ltd. (MELL) (Petitioners), have petitioned the Commission pursuant to 46 CFR 502.74, for an exemption ‘‘equivalent to that contained in 46 CFR 535.307.’’ The Commission's regulations at 46 CFR 535.307 exempt agreements between or among wholly owned subsidiaries from the filing requirements of the Shipping Act. Specifically, Petitioners state that on March 11, 2015, PIL acquired sixty-five (65%) percent of the shares of MELL. Petitioners assert that FMC law and regulations would likely require PIL and MELL to file a number of agreements between themselves with the FMC, delay and what should be routine day-to-day decisions between a parent and its subsidiary.

The Petition in its entirety will be posted on the Commission's Web site at *http://www.fmc.gov/p5-15.* Comments filed in response to this Petition also will be posted on the Commission's Web site at this location.

In order for the Commission to make a thorough evaluation of the Petition, interested persons are requested to submit views or arguments in reply to the Petition no later than November 13, 2015. Commenters must send an original and 5 copies to the Secretary, Federal Maritime Commission, 800 North Capitol Street NW., Washington, DC 20573–0001, and be served on Petitioner's counsel, Neal M. Mayer, Hoppel, Mayer & Coleman, 1050 Connecticut Avenue NW., 10th Floor, Washington, DC 20036. A text-searchable PDF copy of the reply must also be sent as an attachment to *secretary@fmc.gov* and include in the subject line: ‘‘P5–15, PIL and MELL Petition.’’ Replies containing confidential information should not be submitted by email.

Karen V. Gregory,

Secretary.

[FR Doc. 2015–27053 Filed 10–22–15; 8:45 am]

BILLING CODE 6731–AA–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 November 9, 2015.

A. Federal Reserve Bank of Kansas City (Dennis Denney, Assistant Vice President) 1 Memorial Drive, Kansas City, Missouri 64198–0001:

1. *The Franklin D. Gaines Wife's Trust, Beverly J. Tipton, individually and as trustee, Michael D. Jeffers, all of Fredonia, Kansas, and Betheny L. Winkler,* Santa Fe, New Mexico, as trustees; to acquire voting shares of First National Bancshares Corporation of Fredonia, and thereby indirectly acquire voting shares of First National Bank in Fredonia, both in Fredonia, Kansas.

Board of Governors of the Federal Reserve System, October 20, 2015.

Michael J. Lewandowski,

Associate Secretary of the Board.

[FR Doc. 2015–27010 Filed 10–22–15; 8:45 am]

BILLING CODE 6210–01–P

FEDERAL RESERVE SYSTEM

Formations of, Acquisitions by, and Mergers of Bank Holding Companies

The companies listed in this notice have applied to the Board for approval, pursuant to the Bank Holding Company Act of 1956 (12 U.S.C. 1841 *et seq.*) (BHC Act), Regulation Y (12 CFR part 225), and all other applicable statutes and regulations to become a bank holding company and/or to acquire the assets or the ownership of, control of, or the power to vote shares of a bank or bank holding company and all of the banks and nonbanking companies owned by the bank holding company, including the companies listed below.

The applications listed below, as well as other related filings required by the Board, are available for immediate inspection at the Federal Reserve Bank indicated. The applications will also be available for inspection at the offices of the Board of Governors. Interested persons may express their views in writing on the standards enumerated in the BHC Act (12 U.S.C. 1842(c)). If the proposal also involves the acquisition of a nonbanking company, the review also includes whether the acquisition of the nonbanking company complies with the standards in section 4 of the BHC Act (12 U.S.C. 1843). Unless otherwise noted, nonbanking activities will be conducted throughout the United States.

Unless otherwise noted, comments regarding each of these applications must be received at the Reserve Bank indicated or the offices of the Board of Governors not later than November 19, 2015.

A. Federal Reserve Bank of Kansas City (Dennis Denney, Assistant Vice President) 1 Memorial Drive, Kansas City, Missouri 64198–0001:

1. *Farmers Exchange Bancorporation, Inc.,* Cherokee, Oklahoma; to acquire 100 percent of the voting shares of The First National Bank of Nash, Nash, Oklahoma.

Board of Governors of the Federal Reserve System, October 20, 2015.

Michael J. Lewandowski,

Associate Secretary of the Board.

[FR Doc. 2015–26990 Filed 10–22–15; 8:45 am]

BILLING CODE 6210–01–P

FEDERAL RETIREMENT THRIFT INVESTMENT BOARD

Sunshine Act; Notice of Meeting

Agenda

Federal Retirement Thrift Investment Board Member Meeting, October 27, 2015, 8:30 a.m., In-Person Meeting.

Open Session

1. Approval of the Minutes for the September 10, 2015 Board Member Meeting
2. Monthly Reports
   (a) Monthly Participant Activity Report
   (b) Legislative Report
3. Quarterly Reports
   (a) Investment Policy Report
   (b) Vendor Financials
   (c) Audit Status
   (d) Budget Review
   (e) Project Activity Report
4. Capital Market and L Fund
5. Investment Policy
6. Mid-Year Financial Review
7. ORM Report
8. Calendar

Closed Session

9. Security
10. Litigation

Adjourn

This notice serves as a revision to the previously published Sunshine Notice dated October 19, 2015 and published on October 21, 2015 in the **Federal Register**.

Volume 80SR

CONTACT PERSON FOR MORE INFORMATION: Kimberly Weaver, Director, Office of External Affairs, (202) 942–1640.

Dated: October 19, 2015.

Megan Grumbine,

Deputy General Counsel, Federal Retirement Thrift Investment Board.

[FR Doc. 2015–27128 Filed 10–21–15; 11:15 am]

BILLING CODE 6760–01–P

GENERAL SERVICES ADMINISTRATION

[Notice–2015–ISP–2015–02; Docket No. 2015–0002; Sequence 2]

Privacy Act of 1974; Notice of an Updated System of Records

AGENCY: Office of the Chief Information Officer; General Services Administration.

ACTION: Updated notice.

SUMMARY: GSA proposes to update a system of records subject to the Privacy Act of 1974, as amended, 5 U.S.C. 552a.

DATES: *Effective:* November 23, 2015.

ADDRESSES: GSA Privacy Act Officer (ISP), General Services Administration, 1800 F Street NW., Washington, DC 20405.

FOR FURTHER INFORMATION CONTACT: Call the GSA Privacy Act Officer at 202–368–1852 or email *gsa.privacyact@gsa.gov.*

SUPPLEMENTARY INFORMATION: GSA is updating a system of records subject to the Privacy Act of 1974, 5 U.S.C. 552a. The notice provides updated information. Nothing in the notice will impact individuals' rights to access or amend their records in the systems of records.

Dated: October 16, 2015.

David A. Shive,

Chief Information Officer, Office of GSA IT (I).

GSA/GOVT–7

SYSTEM NAME:

HSPD–12 USAccess.

SYSTEM LOCATION:

Records covered by this system are maintained by a contractor at the contractor's site.

CATEGORIES OF INDIVIDUALS COVERED BY THE SYSTEM:

The Personal Identity Verification Identity Management System (PIV IDMS) records will cover all participating agency employees, contractors and their employees, consultants, and volunteers who require routine, long-term access to federal facilities, information technology systems, and networks. The system also includes individuals authorized to perform or use services provided in agency facilities (*e.g.,* Credit Union, Fitness Center, etc.). At their discretion, participating Federal agencies may include short-term employees and contractors in the PIV program and, therefore, inclusion in the PIV IDMS. Federal agencies shall make risk-based decisions to determine whether to issue PIV cards and require prerequisite background checks for short-term employees and contractors. The system does not apply to occasional visitors or short-term guests. GSA and participating agencies will issue temporary identification and credentials for this purpose.

CATEGORIES OF RECORDS IN THE SYSTEM:

Enrollment records maintained in the PIV IDMS on individuals applying for the PIV program and a PIV credential through the GSA HSPD–12 managed service include the following data fields: Full name; Social Security Number; Applicant ID number, date of birth; current address; digital color photograph; fingerprints; biometric template (two fingerprints); organization/office of assignment; employee affiliation; work email address; work telephone number(s); office address; copies of identity source documents; employee status; military status; foreign national status; federal emergency response official status; law enforcement official status; results of background check; Government agency code; and PIV card issuance location. Records in the PIV IDMS needed for credential management for enrolled individuals in the PIV program include: PIV card serial number; digital certificate(s) serial number; PIV card issuance and expiration dates; PIV card PIN; Cardholder Unique Identifier (CHUID); and card management keys. Agencies may also choose to collect the following data at PIV enrollment which would also be maintained in the PIV IDMS: Physical characteristics (*e.g.,* height, weight, and eye and hair color). Individuals enrolled in the PIV managed service will be issued a PIV card. The PIV card contains the following mandatory visual personally identifiable information: Name, photograph, employee affiliation, organizational affiliation, PIV card expiration date, agency card serial number, and color-coding for employee affiliation. Agencies may choose to have the following optional personally identifiable information printed on the card: Cardholder physical characteristics (height, weight, and eye and hair color). The card also contains an integrated circuit chip which is encoded with the following mandatory data elements which comprise the standard data model for PIV logical credentials: PIV card PIN, cardholder unique identifier (CHUID), PIV authentication digital certificate, and two fingerprint biometric templates. The PIV data model may be optionally extended by agencies to include the following logical credentials: Digital certificate for digital signature, digital certificate for key management, card authentication keys, and card management system keys. All PIV logical credentials can only be read by machine.

AUTHORITY FOR MAINTENANCE OF THE SYSTEM:

5 U.S.C. 301; Federal Information Security Management Act of 2002 (44 U.S.C. 3554); E-Government Act of 2002 (Pub. L. 107–347, Sec. 203); Paperwork Reduction Act of 1995 (44 U.S.C. 3501 et al.) and Government Paperwork Elimination Act (Pub. L. 105–277, 44 U.S.C. 3504 note); Homeland Security Presidential Directive 12 (HSPD–12), Policy for a Common Identification Standard for Federal Employees and Contractors, August 27, 2004.

PURPOSES:

The primary purposes of the system are: To ensure the safety and security of Federal facilities, systems, or information, and of facility occupants and users; to provide for interoperability and trust in allowing physical access to individuals entering Federal facilities; and to allow logical access to Federal information systems, networks, and resources on a government-wide basis.

ROUTINE USES OF RECORDS MAINTAINED IN THE SYSTEM INCLUDING CATEGORIES OF USERS AND THE PURPOSES OF SUCH USES:

In addition to those disclosures generally permitted under 5 U.S.C. Section 552a(b) of the Privacy Act, all or a portion of the records or information contained in this system may be disclosed outside GSA as a routine use pursuant to 5 U.S.C. 552a(b)(3) as follows:

a. To the Department of Justice (DOJ) when: (1) The agency or any component thereof; or (2) any employee of the agency in his or her official capacity; (3) any employee of the agency in his or her individual capacity where agency or the Department of Justice has agreed to represent the employee; or (4) the United States Government is a party to litigation or has an interest in such litigation, and by careful review, the agency determines that the records are both relevant and necessary to the litigation and the use of such records by DOJ and is therefore deemed by the agency to be for a purpose compatible with the purpose for which the agency collected the records.

b. To a court or adjudicative body in a proceeding when: (1) The agency or any component thereof; (2) any employee of the agency in his or her official capacity; (3) any employee of the agency in his or her individual capacity where the agency or the Department of Justice has agreed to represent the employee; or (4) the United States Government is a party to litigation or has an interest in such litigation, and by careful review, the agency determines that the records are both relevant and necessary to the litigation and the use of such records and is therefore deemed by the agency to be for a purpose that is compatible with the purpose for which the agency collected the records.

c. Except as noted on Forms SF 85, SF 85–P, and SF 86, when a record on its face, or in conjunction with other records, indicates a violation or potential violation of law, whether civil, criminal, or regulatory in nature, and whether arising by general statute or particular program statute, or by regulation, rule, or order issued pursuant thereto, disclosure may be made to the appropriate public authority, whether Federal, foreign, State, local, or tribal, or otherwise, responsible for enforcing, investigating or prosecuting such violation or charged with enforcing or implementing the statute, or rule, regulation, or order issued pursuant thereto, if the information disclosed is relevant to any enforcement, regulatory, investigative or prosecutorial responsibility of the receiving entity.

d. To a Member of Congress or to a Congressional staff member in response to an inquiry of the Congressional office made at the written request of the constituent about whom the record is maintained.

e. To the National Archives and Records Administration (NARA) or to the General Services Administration for records management inspections conducted under 44 U.S.C. 2904 and 2906.

f. To agency contractors, grantees, or volunteers who have been engaged to assist the agency in the performance of a contract, service, grant, cooperative agreement, or other activity related to this system of records and who need to have access to the records in order to perform their activity. Recipients shall be required to comply with the requirements of the Privacy Act of 1974, as amended, 5 U.S.C. 552a, the Federal Information Security Management Act (Pub. L. 107–296), and associated OMB policies, standards and guidance from the National Institute of Standards and Technology, and the General Services Administration.

g. To a Federal agency, State, local, foreign, or tribal or other public authority, on request, in connection with the hiring or retention of an employee, the issuance or retention of a security clearance, the letting of a contract, or the issuance or retention of a license, grant, or other benefit, to the extent that the information is relevant and necessary to the requesting agency's decision.

h. To the Office of Management and Budget (OMB) when necessary to the review of private relief legislation pursuant to OMB Circular No. A–19.

i. To a Federal, State, or local agency, or other appropriate entities or individuals, or through established liaison channels to selected foreign governments, in order to enable an intelligence agency to carry out its responsibilities under the National Security Act of 1947, as amended; the CIA Act of 1949, as amended; Executive Order 12333 or any successor order; and applicable national security directives, or classified implementing procedures approved by the Attorney General and promulgated pursuant to such statutes, orders, or Directives.

j. To designated agency personnel for controlled access to specific records for the purposes of performing authorized audit or authorized oversight and administrative functions. All access is controlled systematically through authentication using PIV credentials based on access and authorization rules for specific audit and administrative functions.

k. To the Office of Personnel Management (OPM), the Office of Management and Budget (OMB), the Government Accountability Office (GAO), or other Federal agency in accordance with the agency's responsibility for evaluation of Federal personnel management.

l. To the Federal Bureau of Investigation for the FBI National Criminal History check.

m. To appropriate agencies, entities, and persons when (1) the Agency suspects or has confirmed that the security or confidentiality of information in the system of records has been compromised; (2) the Agency has determined that as a result of the suspected or confirmed compromise there is a risk of harm to economic or property interests, identity theft or fraud, or harm to the security or integrity of this system or other systems or programs (whether maintained by GSA or another agency or entity) that rely upon the compromised information; and (3) the disclosure made to such agencies, entities, and persons is reasonably necessary to assist in connection with GSA's efforts to respond to the suspected or confirmed compromise and prevent, minimize, or remedy such harm.

POLICIES AND PRACTICES FOR STORING, RETRIEVING, ACCESSING, RETAINING AND DISPOSING OF RECORDS IN THE SYSTEM:

STORAGE:

Records are stored in electronic media and in paper files.

RETRIEVABILITY:

Records may be retrieved by name of the individual, Cardholder Unique Identification Number, Applicant ID, Social Security Number, and/or by any other unique individual identifier.

SAFEGUARDS:

Consistent with the requirements of the Federal Information Security Management Act (Pub. L. 107–296), and associated OMB policies, standards and guidance from the National Institute of Standards and Technology, and the General Services Administration, the GSA HSPD–12 managed service office protects all records from unauthorized access through appropriate administrative, physical, and technical safeguards. Access is restricted on a ''need to know'' basis, utilization of PIV Card access, secure VPN for Web access, and locks on doors and approved storage containers. Buildings have security guards and secured doors. All entrances are monitored through electronic surveillance equipment. The hosting facility is supported by 24/7 onsite hosting and network monitoring by trained technical staff. Physical security controls include: Indoor and outdoor security monitoring and surveillance; badge and picture ID access screening; biometric access screening. Personally identifiable information is safeguarded and protected in conformance with all Federal statutory and OMB guidance requirements. All access has role-based restrictions, and individuals with access privileges have undergone vetting and suitability screening. All data is encrypted in transit. While it is not contemplated, any system records stored on mobile computers or mobile devices will be encrypted. GSA maintains an audit trail and performs random periodic reviews to identify unauthorized access. Persons given roles in the PIV process must be approved by the Government and complete training specific to their roles to ensure they are knowledgeable about how to protect personally identifiable information.

RETENTION AND DISPOSAL:

Disposition of records will be according to NARA disposition authority N1–269–06–1 (pending).

SYSTEM MANAGER AND ADDRESS:

Director, HSPD–12 Managed Service Office, Federal Acquisition Service (FAS), General Services Administration, 1800 F Street NW., 4th Floor, Washington, DC 20405.

NOTIFICATION PROCEDURE:

A request for access to records in this system may be made by writing to the System Manager. When requesting notification of or access to records covered by this Notice, an individual should provide his/her full name, date of birth, agency name, and work location. An individual requesting notification of records must provide identity documents sufficient to satisfy the custodian of the records that the requester is entitled to access, such as a government-issued photo ID.

RECORD ACCESS PROCEDURES:

Same as Notification Procedure above.

CONTESTING RECORD PROCEDURES:

Same as Notification Procedure above. State clearly and concisely the information being contested, the reasons for contesting it, and the proposed amendment to the information sought.

RECORD SOURCE CATEGORIES:

Employee, contractor, or applicant; sponsoring agency; former sponsoring agency; other Federal agencies; contract employer; former employer.

[FR Doc. 2015–26940 Filed 10–22–15; 8:45 am]

BILLING CODE 6820–38–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Centers for Medicare & Medicaid Services

[CMS–6063–N2]

Medicare Program; Expansion of Prior Authorization for Repetitive Scheduled Non-Emergent Ambulance Transports

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

ACTION: Notice.

SUMMARY: This notice announces an expansion of the 3-year Medicare Prior Authorization Model for Repetitive Scheduled Non-Emergent Ambulance Transport in accordance with section 515(a) of the Medicare Access and CHIP Reauthorization Act of 2015. The model is being expanded to the states of Maryland, Delaware, the District of Columbia, North Carolina, West Virginia, and Virginia.

DATES: This expansion will begin on January 1, 2016 in Maryland, Delaware, the District of Columbia, North Carolina, Virginia, and West Virginia.

FOR FURTHER INFORMATION CONTACT: Angela Gaston, (410) 786–7409.

Questions regarding the Medicare Prior Authorization Model Expansion for Repetitive Scheduled Non-Emergent Ambulance Transport should be sent to *AmbulancePA@cms.hhs.gov.*

SUPPLEMENTARY INFORMATION:

I. Background

Medicare may cover ambulance services, including air ambulance (fixed-wing and rotary-wing) services, if the ambulance service is furnished to a beneficiary whose medical condition is such that other means of transportation are contraindicated. The beneficiary's condition must require both the ambulance transportation itself and the level of service provided in order for the billed service to be considered medically necessary.

Non-emergent transportation by ambulance is appropriate if either the—(1) beneficiary is bed-confined and it is documented that the beneficiary's condition is such that other methods of transportation are contraindicated; or (2) beneficiary's medical condition, regardless of bed confinement, is such that transportation by ambulance is medically required. Thus, bed confinement is not the sole criterion in determining the medical necessity of non-emergent ambulance transportation; rather, it is one factor that is considered in medical necessity determinations.[1]

A repetitive ambulance service is defined as medically necessary ambulance transportation that is furnished in 3 or more round trips during a 10-day period, or at least 1 round trip per week for at least 3 weeks.[2] Repetitive ambulance services are often needed by beneficiaries receiving dialysis or cancer treatment.

Medicare may cover repetitive, scheduled, non-emergent transportation by ambulance if the—(1) medical necessity requirements described previously are met; and (2) ambulance provider/supplier, before furnishing the service to the beneficiary, obtains a written order from the beneficiary's attending physician certifying that the medical necessity requirements are met (see 42 CFR 410.40(d)(1) and (2)).[3]

In addition to the medical necessity requirements, the service must meet all other Medicare coverage and payment requirements, including requirements relating to the origin and destination of the transportation, vehicle and staff, and billing and reporting. Additional information about Medicare coverage of ambulance services can be found in 42 CFR 410.40, 410.41, and in the Medicare Benefit Policy Manual (Pub. 100–02), Chapter 10, at *http://www.cms.gov/Regulations-and-Guidance/Guidance/Manuals/downloads/bp102c10.pdf* .

According to a study published by the Government Accountability Office in October 2012, entitled ''Costs and Medicare Margins Varied Widely; Transports of Beneficiaries Have Increased,'' [4] the number of basic life support (BLS) non-emergent transports for Medicare fee-for-service beneficiaries increased by 59 percent from 2004 to 2010. A similar finding published by the Department of Health and Human Services' Office of Inspector General in a 2006 study, entitled ''Medicare Payments for Ambulance Transports,'' [5] indicated a 20-percent nationwide improper payment rate for non-emergent ambulance transport. Likewise, in June 2013, the Medicare Payment Advisory Commission published a report [6] that included an analysis of non-emergent ambulance transports to dialysis facilities and found that, during the 5-year period between 2007 and 2011, the volume of transports to and from a dialysis facility increased 20 percent, more than twice the rate of all other ambulance transports combined.

Section 1115A of the Social Security Act (the Act) authorizes the Secretary to test innovative payment and service delivery models to reduce program expenditures, while preserving or enhancing the quality of care furnished to Medicare, Medicaid, and Children's Health Insurance Program beneficiaries.

Section 1115A(d)(1) of the Act authorizes the Secretary to waive such requirements of Titles XI and XVIII and of sections 1902(a)(1), 1902(a)(13), and 1903(m)(2)(A)(iii) of the Act as may be necessary solely for purposes of carrying out section 1115A of the Act with respect to testing models described in section 1115A(b) of the Act. For these models, consistent with this standard, we will waive such provisions of sections 1834(a)(15) and 1869(h) of the Act that limit our ability to conduct prior authorization. While these provisions are specific to durable medical equipment and physicians' services, we will waive any portion of these sections as well as any portion of 42 CFR 410.20(d), which implements section 1869(h) of the Act, that could be construed to limit our ability to conduct prior authorization. We have determined that the implementation of this model does not require the waiver of any fraud and abuse law, including sections 1128A, 1128B, and 1877 of the Act. Thus providers and suppliers affected by this model must comply with all applicable fraud and abuse laws.

II. Provisions of the Notice

In the November 14, 2014 **Federal Register** (79 FR 68271), we published a notice entitled ''Medicare Program; Prior Authorization of Repetitive Scheduled Non-emergent Ambulance Transports,'' which announced the implementation of a 3-year Medicare Prior Authorization model that established a process for seeking prior authorizations for repetitive scheduled non-emergent ambulance transport rendered by ambulance providers/suppliers garaged in 3 states (New Jersey, Pennsylvania, and South Carolina). These states were selected as the initial states for the model because of their high utilization and improper payment rates for these services. The model began on December 1, 2014, and will end in all 3 states on December 1, 2017. Prior authorization will not apply to or be given for services furnished after that date.

Section 515(a) of the Medicare Access and CHIP Reauthorization Act of 2015 (MACRA) (Pub. L. 114–10), requires expansion of the previously referenced prior authorization model to cover, effective not later than January 1, 2016, states located in Medicare Administrative Contractor (MAC) regions L and 11 (consisting of Delaware, the District of Columbia, Maryland, New Jersey, Pennsylvania, North Carolina, South Carolina, West Virginia, and Virginia). As such, in accordance with section 515(a) of MACRA, our initial expansion of the prior authorization model for repetitive scheduled non-emergent ambulance transport will include six additional states: Delaware, the District of Columbia, Maryland, North Carolina, Virginia, and West Virginia. This expansion will begin on January 1, 2016. The model will end in all states on December 1, 2017. Prior authorization will not apply to or be given for services furnished after that date.

We will continue to test whether prior authorization helps reduce

[1] 42 CFR 410.40(d)(1).

[2] Program Memorandum Intermediaries/Carriers, Transmittal AB–03–106.

[3] Per 42 CFR 410.40(d)(2), the physician's order must be dated no earlier than 60 days before the date the service is furnished.

[4] Government Accountability Office Cost and Medicare Margins Varied Widely; Transports of Beneficiaries Have Increased (October 2012).

[5] Office of Inspector General Medicare Payment for Ambulance Transport (January 2006).

[6] Medicare Payment Advisory Commission, June 2013, pages 167–193.

expenditures, while maintaining or improving quality of care, using the established prior authorization process for repetitive scheduled non-emergent ambulance transport to reduce utilization of services that do not comply with Medicare policy.

We will continue to use this prior authorization process to help ensure that all relevant clinical or medical documentation requirements are met before services are furnished to beneficiaries and before claims are submitted for payment. This prior authorization process further helps to ensure that payment complies with Medicare documentation, coverage, payment, and coding rules.

The use of prior authorization does not create new clinical documentation requirements. Instead, it requires the same information that is already required to support Medicare payment, just earlier in the process. Prior authorization allows providers and suppliers to address coverage issues prior to furnishing services.

The prior authorization process under this model will apply in the additional six states listed previously for the following codes for Medicare payment:

- A0426 Ambulance service, advanced life support, non-emergency transport, Level 1 (ALS1).
- A0428 Ambulance service, BLS, non-emergency transport.

While prior authorization in the additional six states is not needed for the mileage code, A0425, a prior authorization decision for an A0426 or A0428 code will automatically include the associated mileage code.

Prior to the start of the expansion, we will conduct (and thereafter will continue to conduct) outreach and education to ambulance providers/suppliers, as well as beneficiaries, through such methods as the issuance of an operational guide, frequently asked questions (FAQs) on our Web site, a beneficiary mailing, a physician letter explaining the ambulance providers/suppliers' need for the proper documentation, and educational events and materials issued by the MACs. Additional information about the implementation of the prior authorization model is available on the CMS Web site at *http://go.cms.gov/PAAmbulance.*

Under this model, an ambulance provider/supplier or beneficiary is encouraged to submit to the MAC a request for prior authorization along with all relevant documentation to support Medicare coverage of a repetitive scheduled non-emergent ambulance transport. Submitting a prior authorization request is voluntary. However, if prior authorization has not been requested by the fourth round trip in a 30-day period, the claims will be stopped for pre-payment review.

In order to be provisionally affirmed, the request for prior authorization must meet all applicable rules and policies, and any local coverage determination (LCD) requirements for ambulance transport claims. A provisional affirmation is a preliminary finding that a future claim submitted to Medicare for the service likely meets Medicare's coverage, coding, and payment requirements. After receipt of all relevant documentation, the MACs will make every effort to conduct a review and postmark the notification of their decision on a prior authorization request within 10 business days for an initial submission. Notification will be provided to the ambulance provider/supplier and to the beneficiary. If a subsequent prior authorization request is submitted after a non-affirmative decision on an initial prior authorization request, the MACs will make every effort to conduct a review and postmark the notification of their decision on the request within 20 business days.

An ambulance provider/supplier or beneficiary may request an expedited review when the standard timeframe for making a prior authorization decision could jeopardize the life or health of the beneficiary. If the MAC agrees that the standard review timeframe would put the beneficiary at risk, the MAC will make reasonable efforts to communicate a decision within 2 business days of receipt of all applicable Medicare-required documentation. As this model is for non-emergent services only, we expect requests for expedited reviews to be extremely rare.

A provisional affirmative prior authorization decision may affirm a specified number of trips within a specific amount of time. The prior authorization decision, justified by the beneficiary's condition, may affirm up to 40 round trips (which equates to 80 one-way trips) per prior authorization request in a 60-day period. Alternatively, a provisional affirmative prior authorization decision may affirm less than 40 round trips in a 60-day period, or may affirm a request that seeks to provide a specified number of transports (40 round trips or less) in less than a 60-day period. A provisional affirmative decision can be for all or part of the requested number of trips. Transports exceeding 40 round trips (or 80 one-way trips) in a 60-day period require an additional prior authorization request.

The following describes examples of various prior authorization scenarios:

- *Scenario 1:* When an ambulance provider/supplier or beneficiary submits a prior authorization request to the MAC with appropriate documentation and all relevant Medicare coverage and documentation requirements are met for the ambulance transport, the MAC will send a provisional affirmative prior authorization decision to the ambulance provider/supplier and to the beneficiary. When the claim is submitted to the MAC by the ambulance provider/supplier, it is linked to the prior authorization via the claims processing system and the claim will be paid so long as all Medicare coding, billing, and coverage requirements are met. However, after submission, the claim could be denied for technical reasons, such as the claim was a duplicate claim or the claim was for a deceased beneficiary. In addition, a claim denial could occur because certain documentation, such as the trip record, needed in support of the claim cannot be reviewed on a prior authorization request.
- *Scenario 2:* When an ambulance provider/supplier or beneficiary submits a prior authorization request, but all relevant Medicare coverage requirements are not met, the MAC will send a non-affirmative prior authorization decision to the ambulance provider/supplier and to the beneficiary, advising them that Medicare will not pay for the service. The provider/supplier or beneficiary may then resubmit the request with documentation showing that Medicare requirements have been met. Alternatively, an ambulance provider/supplier could furnish the service, and submit a claim with a non-affirmative prior authorization tracking number, at which point the MAC would deny the claim. The ambulance provider/supplier and the beneficiary would then have the Medicare denial for secondary insurance purposes and would have the opportunity to submit an appeal of the claim denial if they believe Medicare coverage was denied inappropriately.
- *Scenario 3:* When an ambulance provider/supplier or beneficiary submits a prior authorization request with incomplete documentation, a detailed decision letter will be sent to the ambulance provider/supplier and to the beneficiary, with an explanation of what information is missing. The ambulance provider/supplier or beneficiary can rectify the situation and resubmit the prior authorization request with appropriate documentation.
- *Scenario 4:* When an ambulance provider or supplier renders a service to

a beneficiary that is subject to the prior authorization process, and the claim is submitted to the MAC for payment without requesting a prior authorization, the claim will be stopped for prepayment review and documentation will be requested.

++ If the claim is determined not to be medically necessary or to be insufficiently documented, the claim will be denied, and all current policies and procedures regarding liability for payment will apply. The ambulance provider/supplier or the beneficiary or both can appeal the claim denial if they believe the denial was inappropriate.

++ If the claim is determined to be payable, it will be paid.

Under the model, we will work to limit any adverse impact on beneficiaries and to educate beneficiaries about the process. If a prior authorization request is not affirmed, and the claim is still submitted by the provider/supplier, the claim will be denied in full, but beneficiaries will continue to have all applicable administrative appeal rights.

Only one prior authorization request per beneficiary per designated time period can be provisionally affirmed. If the initial provider/supplier cannot complete the total number of prior authorized transports (for example, the initial ambulance company closes or no longer services that area), the initial request is cancelled. In this situation, a subsequent prior authorization request may be submitted for the same beneficiary and must include the required documentation in the submission. If multiple ambulance providers/suppliers are providing transports to the beneficiary during the same or overlapping time period, the prior authorization decision will only cover the provider/supplier indicated in the provisionally affirmed prior authorization request. Any provider/supplier submitting claims for repetitive scheduled non-emergent ambulance transports for which no prior authorization request is recorded will be subject to 100 percent pre-payment medical review of those claims.

Additional information is available on the CMS Web site at *http://go.cms.gov/PAAmbulance.*

III. Collection of Information Requirements

Section 1115A(d)(3) of the Act, as added by section 3021 of the Affordable Care Act, states that chapter 35 of title 44, United States Code (the Paperwork Reduction Act of 1995), shall not apply to the testing and evaluation of models or expansion of such models under this section. Consequently, this document need not be reviewed by the Office of Management and Budget under the authority of the Paperwork Reduction Act of 1995.

IV. Regulatory Impact Statement

This document announces an expansion of the 3-year Medicare Prior Authorization Model for Repetitive Scheduled Non-Emergent Ambulance Transport. Therefore, there are no regulatory impact implications associated with this notice.

Authority: Section 1115A of the Social Security Act.

Dated: October 2, 2015.

Andrew M. Slavitt,

Acting Administrator, Centers for Medicare & Medicaid Services.

[FR Doc. 2015–27030 Filed 10–22–15; 8:45 am]

BILLING CODE P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Food and Drug Administration

[Docket No. FDA–2014–N–1960]

Agency Information Collection Activities; Announcement of Office of Management and Budget Approval; MedWatch: The Food and Drug Administration Medical Products Reporting Program

AGENCY: Food and Drug Administration, HHS.

ACTION: Notice.

SUMMARY: The Food and Drug Administration (FDA) is announcing that a collection of information entitled ''MedWatch: The Food and Drug Administration Medical Products Reporting Program'' has been approved by the Office of Management and Budget (OMB) under the Paperwork Reduction Act of 1995.

FOR FURTHER INFORMATION CONTACT: FDA PRA Staff, Office of Operations, Food and Drug Administration, 8455 Colesville Rd., COLE–14526, Silver Spring, MD 20993–0002, *PRAStaff@fda.hhs.gov.*

SUPPLEMENTARY INFORMATION: On June 11, 2015, the Agency submitted a proposed collection of information entitled ''MedWatch: The Food and Drug Administration Medical Products Reporting Program'' to OMB for review and clearance under 44 U.S.C. 3507. 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. OMB has now approved the information collection and has assigned OMB control number 0910–0291. The approval expires on September 30, 2018. A copy of the supporting statement for this information collection is available on the Internet at *http://www.reginfo.gov/public/do/PRAMain.*

Dated: October 15, 2015.

Leslie Kux,

Associate Commissioner for Policy.

[FR Doc. 2015–26923 Filed 10–22–15; 8:45 am]

BILLING CODE 4164–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Food and Drug Administration

[Docket No. FDA–2014–N–1048]

Agency Information Collection Activities; Announcement of Office of Management and Budget Approval; Medical Device Labeling Regulations

AGENCY: Food and Drug Administration, HHS.

ACTION: Notice.

SUMMARY: The Food and Drug Administration (FDA) is announcing that a collection of information entitled ''Medical Device Labeling Regulations'' has been approved by the Office of Management and Budget (OMB) under the Paperwork Reduction Act of 1995.

FOR FURTHER INFORMATION CONTACT: FDA PRA Staff, Office of Operations, Food and Drug Administration, 8455 Colesville Rd., COLE–14526, Silver Spring, MD 20993–0002, *PRAStaff@fda.hhs.gov.*

SUPPLEMENTARY INFORMATION: On January 30, 2015, the Agency submitted a proposed collection of information entitled ''Medical Device Labeling Regulations'' to OMB for review and clearance under 44 U.S.C. 3507. 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. OMB has now approved the information collection and has assigned OMB control number 0910–0485. The approval expires on September 30, 2018. A copy of the supporting statement for this information collection is available on the Internet at *http://www.reginfo.gov/public/do/PRAMain.*

Dated: October 16, 2015.

Leslie Kux,

Associate Commissioner for Policy.

[FR Doc. 2015–26986 Filed 10–22–15; 8:45 am]

BILLING CODE 4164–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Food and Drug Administration

[Docket No. FDA–2012–N–0560]

Agency Information Collection Activities; Proposed Collection; Comment Request; Guidance on Informed Consent for In Vitro Diagnostic Device Studies Using Leftover Human Specimens That Are Not Individually Identifiable

AGENCY: Food and Drug Administration, HHS.

ACTION: Notice.

SUMMARY: The Food and Drug Administration (FDA) is announcing an opportunity for public comment on the proposed collection of certain information by the Agency. Under the Paperwork Reduction Act of 1995 (the PRA), Federal Agencies are required to publish notice in the **Federal Register** concerning each proposed collection of information, including each proposed extension of an existing collection of information, and to allow 60 days for public comment in response to the notice. This notice solicits comments on the guidance on informed consent for in vitro diagnostic device studies using leftover human specimens that are not individually identifiable.

DATES: Submit either electronic or written comments on the collection of information by December 22, 2015.

ADDRESSES: You may submit comments as follows:

Electronic Submissions

Submit electronic comments in the following way:

- *Federal eRulemaking Portal: http://www.regulations.gov.* Follow the instructions for submitting comments. Comments submitted electronically, including attachments, to *http://www.regulations.gov* will be posted to the docket unchanged. Because your comment will be made public, you are solely responsible for ensuring that your comment does not include any confidential information that you or a third party may not wish to be posted, such as medical information, your or anyone else's Social Security number, or confidential business information, such as a manufacturing process. Please note that if you include your name, contact information, or other information that identifies you in the body of your comments, that information will be posted on *http://www.regulations.gov.*
- If you want to submit a comment with confidential information that you do not wish to be made available to the public, submit the comment as a written/paper submission and in the manner detailed (see ''Written/Paper Submissions'' and ''Instructions'').

Written/Paper Submissions

Submit written/paper submissions as follows:

- *Mail/Hand delivery/Courier (for written/paper submissions):* Division of Dockets Management (HFA–305), Food and Drug Administration, 5630 Fishers Lane, Rm. 1061, Rockville, MD 20852.
- For written/paper comments submitted to the Division of Dockets Management, FDA will post your comment, as well as any attachments, except for information submitted, marked and identified, as confidential, if submitted as detailed in ''Instructions.''

Instructions: All submissions received must include the Docket No. FDA–2012–N–0560 for ''Agency Information Collection Activities; Proposed Collection; Comment Request; Guidance on Informed Consent for In Vitro Diagnostic Device Studies Using Leftover Human Specimens That Are Not Individually Identifiable.'' Received comments will be placed in the docket and, except for those submitted as ''Confidential Submissions,'' publicly viewable at *http://www.regulations.gov* or at the Division of Dockets Management between 9 a.m. and 4 p.m., Monday through Friday.

- Confidential Submissions—To submit a comment with confidential information that you do not wish to be made publicly available, submit your comments only as a written/paper submission. You should submit two copies total. One copy will include the information you claim to be confidential with a heading or cover note that states ''THIS DOCUMENT CONTAINS CONFIDENTIAL INFORMATION.'' The Agency will review this copy, including the claimed confidential information, in its consideration of comments. The second copy, which will have the claimed confidential information redacted/blacked out, will be available for public viewing and posted on *http://www.regulations.gov.* Submit both copies to the Division of Dockets Management. If you do not wish your name and contact information to be made publicly available, you can provide this information on the cover sheet and not in the body of your comments and you must identify this information as ''confidential.'' Any information marked as ''confidential'' will not be disclosed except in accordance with 21 CFR 10.20 and other applicable disclosure law. For more information about FDA's posting of comments to public dockets, see 80 FR 56469, September 18, 2015, or access the information at: *http://www.fda.gov/regulatoryinformation/dockets/default.htm.*

Docket: For access to the docket to read background documents or the electronic and written/paper comments received, go to *http://www.regulations.gov* and insert the docket number, found in brackets in the heading of this document, into the ''Search'' box and follow the prompts and/or go to the Division of Dockets Management, 5630 Fishers Lane, Rm. 1061, Rockville, MD 20852.

FOR FURTHER INFORMATION CONTACT: FDA PRA Staff, Office of Operations, Food and Drug Administration, 8455 Colesville Rd., COLE–14526, Silver Spring, MD 20993–0002, *PRAStaff@fda.hhs.gov.*

SUPPLEMENTARY INFORMATION: Under the 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. ''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 provide a 60-day notice in the **Federal Register** concerning each proposed collection of information, including each proposed extension of an existing collection of information, before submitting the collection to OMB for approval. To comply with this requirement, FDA is publishing notice of the proposed collection of information set forth in this document.

With respect to the following collection of information, FDA invites comments on these topics: (1) Whether the proposed collection of information is necessary for the proper performance of FDA's functions, including whether the information will have practical utility; (2) the accuracy of FDA's estimate of the burden of the proposed collection of information, including the validity of the methodology and assumptions used; (3) ways to enhance the quality, utility, and clarity of the information to be collected; and (4) ways to minimize the burden of the collection of information on respondents, including through the use of automated collection techniques, when appropriate, and other forms of information technology.

Guidance on Informed Consent for In Vitro Diagnostic Device Studies Using Leftover Human Specimens That Are Not Individually Identifiable—OMB Control Number 0910–0582—Extension

FDA's investigational device regulations are intended to encourage the development of new, useful devices in a manner that is consistent with public health, safety, and compliant with ethical standards. Investigators should have freedom to pursue the least burdensome means of accomplishing this goal. However, to ensure that the balance is maintained between product development and the protection of public health, safety, and ethical standards, FDA has established human subject protection regulations addressing requirements for informed consent and institutional review board (IRB) review that apply to all FDA-regulated clinical investigations involving human subjects. In particular, informed consent requirements further both safety and ethical considerations by allowing potential subjects to consider both the physical and privacy risks they face if they agree to participate in a trial.

Under FDA regulations, clinical investigations using human specimens conducted in support of premarket submissions to FDA are considered human subject investigations (see 21 CFR 812.3(p)). Many investigational device studies are exempt from most provisions of part 812, Investigational Device Exemptions, under 21 CFR 812.2(c)(3), but FDA's regulations for the protection of human subjects (21 CFR parts 50 and 56) apply to all clinical investigations that are regulated by FDA (see 21 CFR 50.1, 21 CFR 56.101, 21 U.S.C. 360j(g)(3)(A), and 21 U.S.C. 360j(g)(3)(D)).

FDA regulations do not contain exceptions from the requirements of informed consent on the grounds that the specimens are not identifiable or that they are remnants of human specimens collected for routine clinical care or analysis that would otherwise have been discarded. Nor do FDA regulations allow IRBs to decide whether or not to waive informed consent for research involving leftover or unidentifiable specimens.

In a level 1 guidance document, entitled ''Guidance on Informed Consent for In Vitro Diagnostic Device Studies Using Leftover Human Specimens that are Not Individually Identifiable,'' issued under the Good Guidances Practices regulation, 21 CFR 10.115, FDA outlines the circumstances in which it intends to exercise enforcement discretion as to the informed consent regulations for clinical investigators, sponsors, and IRBs.

The recommendations of the guidance impose a minimal burden on industry. FDA estimates that 700 studies will be affected annually. Each study will result in one annual record, estimated to take 4 hours to complete. This results in a total recordkeeping burden of 2,800 hours (700 × 4 = 2,800).

FDA estimates the burden of this collection of information as follows:

TABLE 1—ESTIMATED ANNUAL RECORDKEEPING BURDEN [1]

FD&C Act section	No. of recordkeepers	No. of records per recordkeeper	Total annual records	Average burden per recordkeeping	Total hours
520(g)	700	1	700	4	2,800

[1] There are no capital costs or operating and maintenance costs associated with this collection of information.

Dated: October 15, 2015.

Leslie Kux,

Associate Commissioner for Policy.

[FR Doc. 2015–26985 Filed 10–22–15; 8:45 am]

BILLING CODE 4164–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Food and Drug Administration

[Docket No. FDA–2011–N–0793]

Agency Information Collection Activities; Announcement of Office of Management and Budget Approval; Medical Device Recall Authority

AGENCY: Food and Drug Administration, HHS.

ACTION: Notice.

SUMMARY: The Food and Drug Administration (FDA) is announcing that a collection of information entitled ''Medical Device Recall Authority'' has been approved by the Office of Management and Budget (OMB) under the Paperwork Reduction Act of 1995.

FOR FURTHER INFORMATION CONTACT: FDA PRA Staff, Office of Operations, Food and Drug Administration, 8455 Colesville Rd., COLE–14526, Silver Spring, MD 20993–0002, *PRAStaff@fda.hhs.gov.*

SUPPLEMENTARY INFORMATION: On June 15, 2015, the Agency submitted a proposed collection of information entitled ''Medical Device Recall Authority'' to OMB for review and clearance under 44 U.S.C. 3507. 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. OMB has now approved the information collection and has assigned OMB control number 0910–0432. The approval expires on September 30, 2018. A copy of the supporting statement for this information collection is available on the Internet at *http://www.reginfo.gov/public/do/PRAMain.*

Dated: October 15, 2015.

Leslie Kux,

Associate Commissioner for Policy.

[FR Doc. 2015–26924 Filed 10–22–15; 8:45 am]

BILLING CODE 4164–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Public Meeting of the Presidential Commission for the Study of Bioethical Issues

AGENCY: Presidential Commission for the Study of Bioethical Issues, Office of the Assistant Secretary for Health, Office of the Secretary, Department of Health and Human Services.

ACTION: Notice of meeting.

SUMMARY: The Presidential Commission for the Study of Bioethical Issues (the Commission) will conduct its twenty third meeting on November 17, 2015. At this meeting, the Commission will continue to discuss the role of deliberation and deliberative methods to engage the public and inform consideration in bioethics, and how to integrate pubic dialogue into the bioethics conversation; bioethics education as a forum for fostering deliberative skills, and preparing students to participate in public dialogue in bioethics; goals and methods of bioethics education; and integrating bioethics education across a

range of professional disciplines and educational levels.

DATES: The meeting will take place November 17, 2015, from 9 a.m. to approximately 5 p.m.

ADDRESSES: Hilton Arlington Hotel, 950 North Stafford Street, Arlington, VA 22203.

FOR FURTHER INFORMATION CONTACT: Lisa M. Lee, Executive Director, Presidential Commission for the Study of Bioethical Issues, 1425 New York Avenue NW., Suite C–100, Washington, DC 20005. Telephone: 202–233–3960. Email: *Lisa.Lee@bioethics.gov.* Additional information may be obtained at *www.bioethics.gov.*

SUPPLEMENTARY INFORMATION: Pursuant to the Federal Advisory Committee Act of 1972, Public Law 92–463, 5 U.S.C. app. 2, notice is hereby given for the twenty-third meeting of the Commission. The meeting will be open to the public with attendance limited to space available. The meeting will also be webcast at *www.bioethics.gov.*

Under authority of Executive Order 13521, dated November 24, 2009, the President established the Commission. The Commission is an expert panel of not more than 13 members who are drawn from the fields of bioethics, science, medicine, technology, engineering, law, philosophy, theology, or other areas of the humanities or social sciences. The Commission advises the President on bioethical issues arising from advances in biomedicine and related areas of science and technology. The Commission seeks to identify and promote policies and practices that ensure scientific research, health care delivery, and technological innovation are conducted in a socially and ethically responsible manner.

The main agenda items for the Commission's twenty-third meeting are to continue discussing the role of deliberation and deliberative methods to engage the public in bioethics, and how to integrate pubic dialogue into the bioethics conversation; bioethics education as a forum for fostering deliberative skills, and preparing students to participate in public dialogue in bioethics; goals and methods of bioethics education; and integrating bioethics education across a range of professional disciplines and educational levels. The draft meeting agenda and other information about the Commission, including information about access to the webcast, will be available at *www.bioethics.gov.*

The Commission welcomes input from anyone wishing to provide public comment on any issue before it. Respectful consideration of opposing views and active participation by citizens in public exchange of ideas enhances overall public understanding of the issues at hand and conclusions reached by the Commission. The Commission is particularly interested in receiving comments and questions during the meeting that are responsive to specific sessions. Written comments will be accepted at the registration desk and comment forms will be provided to members of the public in order to write down questions and comments for the Commission as they arise. To accommodate as many individuals as possible, the time for each question or comment may be limited. If the number of individuals wishing to pose a question or make a comment is greater than can reasonably be accommodated during the scheduled meeting, the Commission may make a random selection.

Written comments will also be accepted in advance of the meeting and are especially welcome. Please address written comments by email to *info@bioethics.gov,* or by mail to the following address: Public Commentary, Presidential Commission for the Study of Bioethical Issues, 1425 New York Avenue NW., Suite C–100, Washington, DC 20005. Comments will be publicly available, including any personally identifiable or confidential business information that they contain. Trade secrets should not be submitted.

Anyone planning to attend the meeting who needs special assistance, such as sign language interpretation or other reasonable accommodations, should notify Esther Yoo by telephone at (202) 233–3960, or email at *Esther.Yoo@bioethics.gov* in advance of the meeting. The Commission will make every effort to accommodate persons who need special assistance.

Dated: October 9, 2015.

Lisa M. Lee,

Executive Director, Presidential Commission for the Study of Bioethical Issues.

[FR Doc. 2015–26905 Filed 10–22–15; 8:45 am]

BILLING CODE 4154–06–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Meeting of the Advisory Committee on Blood and Tissue Safety and Availability

AGENCY: Office of the Assistant Secretary for Health, Office of the Secretary, Department of Health and Human Services.

ACTION: Notice.

SUMMARY: As stipulated by the Federal Advisory Committee Act, the U.S. Department of Health and Human Services is hereby giving notice that the Advisory Committee on Blood and Tissue Safety and Availability (ACBTSA) will hold a meeting. The meeting will be open to the public.

DATES: The meeting will take place Monday, November 9, 2015, from 8:00 a.m.–4:30 p.m. and Tuesday, November 10, 2015, from 8:00 a.m.–4:00 p.m.

ADDRESSES: Veterans' Health Administration National Conference Center, 2011 Crystal Drive, 1st floor Conference Center, Crystal City, VA 22202.

FOR FURTHER INFORMATION CONTACT: Mr. James Berger, Designated Federal Officer for the ACBTSA, Senior Advisor for Blood and Tissue Policy, Office of the Assistant Secretary for Health, Department of Health and Human Services, 1101 Wootton Parkway, Suite 250, Rockville, MD 20852. Phone: (240) 453–8803; Fax (240) 453–8456; Email *ACBTSA@hhs.gov*.

SUPPLEMENTARY INFORMATION: The ACBTSA provides advice to the Secretary through the Assistant Secretary for Health. The Committee advises on a range of policy issues to include: (1) Identification of public health issues through surveillance of blood and tissue safety issues with national biovigilance data tools; (2) identification of public health issues that affect availability of blood, blood products, and tissues; (3) broad public health, ethical and legal issues related to the safety of blood, blood products, and tissues; (4) the impact of various economic factors (*e.g.,* product cost and supply) on safety and availability of blood, blood products, and tissues; (5) risk communications related to blood transfusion and tissue transplantation; and (6) identification of infectious disease transmission issues for blood, organs, blood stem cells and tissues. The Committee has met regularly since its establishment in 1997.

In December 2013, the Committee made recommendations regarding the blood system. At that time, the Committee expressed concern about the ongoing reductions in blood use, the number of large scale consolidations occurring, the cost recovery issues for blood centers, and the potential effects on safety and innovation due to instability. Past recommendations made by the ACBTSA may be viewed at *www.hhs.gov/bloodsafety*.

This meeting will provide a focused examination of the mechanisms to fund recently approved blood safety innovations, such as pathogen reduction, bacterial testing, and infectious disease testing. It is anticipated that the implementation of these blood safety innovations will come with significant costs to blood collection centers, and it remains unclear how or if the blood industry can afford such implementation. Speakers will include a broad range of stakeholders including blood banks, physicians, blood purchasers, and organizations that reimburse for blood and blood products.

The public will have an opportunity to present their views to the Committee during a public comment session scheduled for November 10, 2015. Comments will be limited to five minutes per speaker and must be pertinent to the discussion. Pre-registration is required for participation in the public comment session. Any member of the public who would like to participate in this session is required to contact the Designated Federal Officer at his/her earliest convenience to register for time (limited to 5 minutes); registration must be completed prior to close of business on November 2, 2015. If it is not possible to provide 30 copies of the material to be distributed at the meeting, then individuals are requested to provide a minimum of one (1) copy of the document(s) to be distributed prior to the close of business on November 2, 2015. It is also requested that any member of the public who wishes to provide comments to the Committee utilizing electronic data projection submit the necessary material to the Designated Federal Officer prior to the close of business on November 2, 2015.

Dated: October 16, 2015.

James J. Berger,

Senior Advisor for Blood and Tissue Safety Policy.

[FR Doc. 2015–26904 Filed 10–22–15; 8:45 am]

BILLING CODE 4150–41–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

National Eye Institute; 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 Eye Institute Special Emphasis Panel NEI Clinical and Epidemiological Applications: Uveitis, Cornea and Refractive Error.

Date: November 10, 2015.

Time: 8:00 a.m. to 5:00 p.m.

Agenda: To review and evaluate grant applications.

Place: Hilton Garden Inn Bethesda, 7301 Waverly Street, Bethesda, MD 20814.

Contact Person: JEANETTE M HOSSEINI, Ph.D. Scientific Review Officer, 5635 Fishers Lane, Suite 1300, Bethesda, MD 20892, 301–451–2020, *jeanetteh@mail.nih.gov.*

(Catalogue of Federal Domestic Assistance Program Nos. 93.867, Vision Research, National Institutes of Health, HHS)

Dated: October 19, 2015.

Natasha Copeland,

Program Analyst, Office of Federal Advisory Committee Policy.

[FR Doc. 2015–26926 Filed 10–22–15; 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: Addictions, Depression, Bipolar Disorder, Schizophrenia.

Date: November 10, 2015.

Time: 11:00 a.m. to 4:00 p.m.

Agenda: To review and evaluate grant applications.

Place: National Institutes of Health, 6701 Rockledge Drive, Bethesda, MD 20892 (Virtual Meeting).

Contact Person: Samuel C. Edwards, Ph.D., IRG CHIEF, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 5210, MSC 7846, Bethesda, MD 20892, (301) 435–1246, *edwardss@csr.nih.gov.*

Name of Committee: Center for Scientific Review Special Emphasis Panel; Small Business: Psycho/Neuropathology, Lifespan Development, and STEM Education.

Date: November 16–17, 2015.

Time: 8:00 a.m. to 5:00 p.m.

Agenda: To review and evaluate grant applications.

Place: Hilton Long Beach and Executive Center, 701 West Ocean Boulevard, Long Beach, CA 90831.

Contact Person: John H Newman, Ph.D., Scientific Review Officer, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 3222, MSC 7808, Bethesda, MD 20892, (301) 435–0628, *newmanjh@csr.nih.gov.*

Name of Committee: Center for Scientific Review Special Emphasis Panel; PAR Panel: Basic Research on HIV Persistence.

Date: November 18, 2015.

Time: 8:00 a.m. to 6:00 p.m.

Agenda: To review and evaluate grant applications.

Place: The Fairmont Washington, DC, 2401 M Street NW., Washington, DC 20037.

Contact Person: Kenneth A. Roebuck, Ph.D., Scientific Review Officer, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 5106, MSC 7852, Bethesda, MD 20892, (301) 435–1166, *roebuckk@csr.nih.gov.*

Name of Committee: Center for Scientific Review Special Emphasis Panel; Small Business: Cell and Molecular Biology.

Date: November 18–19, 2015.

Time: 8:00 a.m. to 5:00 p.m.

Agenda: To review and evaluate grant applications.

Place: Renaissance Arlington Capital View, 2800 South Potomac Ave, Arlington, VA.

Contact Person: Maria DeBernardi, Ph.D., Scientific Review Officer, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 6158, MSC 7892, Bethesda, MD 20892, 301–435–1355, *debernardima@csr.nih.gov.*

Name of Committee: Center for Scientific Review Special Emphasis Panel; Small Business: Dermatology, Rheumatology and Inflammation.

Date: November 18, 2015.

Time: 9:00 a.m. to 5:00 p.m.

Agenda: To review and evaluate grant applications.

Place: National Institutes of Health, 6701 Rockledge Drive, Bethesda, MD 20892.

Contact Person: Yanming Bi, Ph.D., Scientific Review Officer, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 4214, MSC 7814, Bethesda, MD 20892, 301–451–0996, *ybi@csr.nih.gov.*

Name of Committee: Center for Scientific Review Special Emphasis Panel; Fellowships: Learning, Memory, Language, Communication and Related Neurosciences.

Date: November 18, 2015.

Time: 10:00 a.m. to 5:00 p.m.

Agenda: To review and evaluate grant applications.

Place: National Institutes of Health, 6701 Rockledge Drive, Bethesda, MD 20892 (Virtual Meeting).

Contact Person: Joseph G. Rudolph, Ph.D., Chief and Scientific Review Officer, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 5186, MSC 7844, Bethesda, MD 20892, 301–408–9098, *josephru@csr.nih.gov.*

Name of Committee: Center for Scientific Review Special Emphasis Panel; Small Business: Endocrinology, Metabolism, Nutrition, and Reproductive Sciences.

Date: November 18–19, 2015.

Time: 10:00 a.m. to 2:00 p.m.

Agenda: To review and evaluate grant applications.

Place: National Institutes of Health, 6701 Rockledge Drive, Bethesda, MD 20892 (Virtual Meeting).

Contact Person: Clara M. Cheng, Ph.D., Scientific Review Officer, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 6170 MSC 7892, Bethesda, MD 20817, 301–435–1041, *chengc@csr.nih.gov.*

Name of Committee: Center for Scientific Review Special Emphasis Panel; Member Conflict: Biological Chemistry and Macromolecular Biophysics.

Date: November 18, 2015.

Time: 10:00 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: Michael Eissenstat, Ph.D., Scientific Review Officer, BCMB IRG, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 4166, Bethesda, MD 20892, 301–435–1722, *eissenstatma@csr.nih.gov.*

Name of Committee: Center for Scientific Review Special Emphasis Panel; Shared Instrumentation: NMR and X-ray.

Date: November 18, 2015

Time: 11:00 a.m. to 5:00 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: William A Greenberg, Ph.D., Scientific Review Officer, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 4168, MSC 7806, Bethesda, MD 20892, (301) 435–1726, *greenbergwa@csr.nih.gov.*

Name of Committee: Center for Scientific Review Special Emphasis Panel; Member Conflict: Bioengineering Sciences Drug Delivery, Biomaterials, Nanotechnology and Instrumentation.

Date: November 18, 2015.

Time: 1:00 p.m. to 5:00 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: Joseph Thomas Peterson, Ph.D., Scientific Review Officer, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 4118, MSC 7814, Bethesda, MD 20892, 301–408–9694, *petersonjt@csr.nih.gov.*

Name of Committee: Center for Scientific Review Special Emphasis Panel; Member Conflict: Immune Mechanisms.

Date: November 18, 2015.

Time: 1:00 p.m. to 5:00 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: Jian Wang, Ph.D., Scientific Review Officer, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 4095D, MSC 7812, Bethesda, MD 20892, (301) 435–2778, *wangjia@csr.nih.gov.*

Name of Committee: Center for Scientific Review Special Emphasis Panel; Member Conflict: Bacterial and Eukaryotic Molecular Genetics.

Date: November 18, 2015.

Time: 1:30 p.m. to 4:30 p.m.

Agenda: To review and evaluate grant applications and/or proposals.

Place: National Institutes of Health, 6701 Rockledge Drive, Bethesda, MD 20892 (Telephone Conference Call).

Contact Person: Ronald Adkins, Ph.D., Scientific Review Officer, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 2206, MSC 7890, Bethesda, MD 20892, 301–435–4511, *ronald.adkins@nih.gov.*

Name of Committee: Center for Scientific Review Special Emphasis Panel; AREA Grant Application Review.

Date: November 18, 2015.

Time: 2:00 p.m. to 5:00 p.m.

Agenda: To review and evaluate grant applications.

Place: National Institutes of Health, 6701 Rockledge Drive, Bethesda, MD 20892.

Contact Person: Angela Y. Ng, Ph.D., MBA, Scientific Review Officer, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 6200, MSC 7804, Bethesda, MD 20892, 301–435–1715, *nga@csr.nih.gov.*

Name of Committee: Center for Scientific Review Special Emphasis Panel; Member Conflict: Sleep, Psychopathology, Emotion, and Stress.

Date: November 18, 2015.

Time: 12:30 p.m. to 3:30 p.m.

Agenda: To review and evaluate grant applications.

Place: National Institutes of Health, 6701 Rockledge Drive, Bethesda, MD 20892 (Virtual Meeting).

Contact Person: Andrea B. Kelly, Ph.D., Scientific Review Officer, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 3182, MSC 7770, Bethesda, MD 20892, (301) 455–1761, *kellya2@csr.nih.gov.*

Name of Committee: Center for Scientific Review Special Emphasis Panel; AIDS and AIDS Related Applications.

Date: November 19, 2015.

Time: 8:00 a.m. to 5:00 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: Jingsheng Tuo, Ph.D., Scientific Review Officer, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 3196, Bethesda, MD 20892, 301–451–5953, *tuoj@csr.nih.gov.*

Name of Committee: Center for Scientific Review Special Emphasis Panel; Bioengineering Sciences and Technologies: AREA Review.

Date: November 19, 2015.

Time: 8:00 a.m. to 6:00 p.m.

Agenda: To review and evaluate grant applications.

Place: Hilton Garden Inn Bethesda, 7301 Waverly Street, Bethesda, MD 20814.

Contact Person: Nancy Templeton, Ph.D., Scientific Review Officer, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 5168, MSC 7849, Bethesda, MD 20892, 301–408–9694, *templetonns@mail.nih.gov.*

Name of Committee: Center for Scientific Review Special Emphasis Panel; Small Business: Non-HIV Diagnostics, Food Safety, Sterilization/Disinfection, and Bioremediation.

Date: November 19–20, 2015.

Time: 8:00 a.m. to 5:30 p.m.

Agenda: To review and evaluate grant applications.

Place: Hilton Garden Inn Bethesda, 7301 Waverly Street, Bethesda, MD 20814.

Contact Person: Gagan Pandya, Ph.D., Scientific Review Officer, National Institutes of Health, Center for Scientific Review, 6701 Rockledge Drive, RM 3200, MSC 7808, Bethesda, MD 20892, 301–435–1167, *pandyaga@mai.nih.gov.*

Name of Committee: Center for Scientific Review Special Emphasis Panel; Small Business: Cancer Diagnostics and Treatments (CDT).

Date: November 19–20, 2015.

Time: 8:00 a.m. to 5:00 p.m.

Agenda: To review and evaluate grant applications.

Place: JW Marriott New Orleans, 614 Canal Street, New Orleans, LA 70130.

Contact Person: Zhang-Zhi Hu, MD, Scientific Review Officer, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 6186, MSC 7804, Bethesda, MD 20892, (301) 594–2414, *huzhuang@csr.nih.gov.*

Name of Committee: Center for Scientific Review Special Emphasis Panel; Small Business: Computational, Modeling, and Biodata Management.

Date: November 19, 2015.

Time: 8:00 a.m. to 6:00 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: Allen Richon, Ph.D., Scientific Review Officer, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 6184, MSC 7892, Bethesda, MD 20892, 301–379–9351, *allen.richon@nih.hhs.gov.*

Name of Committee: Center for Scientific Review Special Emphasis Panel; Small Business: Medical Imaging.

Date: November 19–20, 2015.

Time: 8:00 a.m. to 5:00 p.m.

Agenda: To review and evaluate grant applications.

Place: Hilton Alexandria Mark Center, 5000 Seminary Rd, Alexandria, VA 22311.

Contact Person: Leonid V. Tsap, Ph.D., Scientific Review Officer, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 5128, MSC 7854, Bethesda, MD 20892, (301) 435–2507, *tsapl@csr.nih.gov.*

Name of Committee: AIDS and Related Research Integrated Review Group; HIV/AIDS Vaccines Study Section.

Date: November 19, 2015.

Time: 8:00 a.m. to 6:00 p.m.

Agenda: To review and evaluate grant applications.

Place: The Fairmont Washington, DC, 2401 M Street NW., Washington, DC 20037.

Contact Person: Barna Dey, Ph.D., Scientific Review Officer, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 3184, Bethesda, MD 20892, 301–435–0000, *bdey@mail.nih.gov.*

Name of Committee: Center for Scientific Review Special Emphasis Panel; Small Business: Respiratory Sciences.

Date: November 19–20, 2015.

Time: 9:00 a.m. to 5:00 p.m.

Agenda: To review and evaluate grant applications.

Place: National Institutes of Health, 6701 Rockledge Drive, Bethesda, MD 20892 (Virtual Meeting).

Contact Person: Ghenima Dirami, Ph.D., Scientific Review Officer, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 4122, MSC 7814, Bethesda, MD 20892, 240–498–7546, *diramig@csr.nih.gov.*

Name of Committee: Center for Scientific Review Special Emphasis Panel; Mental Illness Clinical Studies.

Date: November 19, 2015.

Time: 1:00 p.m. to 5:00 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: Savvas Makrides, Ph.D., Scientific Review Officer, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 2200, Bethesda, MD 20892, 301–435–2514, *makridessc@mail.nih.gov.*

Name of Committee: Center for Scientific Review Special Emphasis Panel; Small Business: Innovative Immunology Research.

Date: November 20, 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: Deborah Hodge, Ph.D., Scientific Review Officer, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 4207, MSC 7812, Bethesda, MD 20892, (301) 435–1238, *hodged@mail.nih.gov.*

Name of Committee: AIDS and Related Research Integrated Review Group; NeuroAIDS and other End-Organ Diseases Study Section.

Date: November 20, 2015.

Time: 8:00 a.m. to 6:00 p.m.

Agenda: To review and evaluate grant applications.

Place: Fairmont Hotel San Francisco, 950 Mason Street, San Francisco, CA 94108.

Contact Person: Eduardo A. Montalvo, Ph.D., Scientific Review Officer, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 5108, MSC 7852, Bethesda, MD 20892, (301) 435–1168, *montalve@csr.nih.gov.*

Name of Committee: AIDS and Related Research Integrated Review Group; AIDS Immunology and Pathogenesis Study Section.

Date: November 20, 2015.

Time: 8:00 a.m. to 6:00 p.m.

Agenda: To review and evaluate grant applications.

Place: The Fairmont Washington, DC, 2401 M Street, NW., Washington, DC 20037.

Contact Person: Shiv A. Prasad, Ph.D., Scientific Review Officer, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 5220, MSC 7852, Bethesda, MD 20892, 301–443–5779, *prasads@csr.nih.gov.*

Name of Committee: Center for Scientific Review Special Emphasis Panel; PAR–15–088: Shared Instrumentation Miscellaneous.

Date: November 20, 2015.

Time: 11:00 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: Marie-Jose Belanger, Ph.D., Scientific Review Officer, Center for Scentific Review, National Institutes of Health, 6701 Rockledge Drive, Room 5181, MSC, Bethesda, MD 20892, *belangerm@csr.nih.gov.*

Name of Committee: Center for Scientific Review Special Emphasis Panel; PAR–14–281: Connectomes Related to Human Disease.

Date: November 20, 2015.

Time: 11:00 a.m. to 5:00 p.m.

Agenda: To review and evaluate grant applications.

Place: National Institutes of Health, 6701 Rockledge Drive, Bethesda, MD 20892.

Contact Person: Eugene Carstea, Ph.D., Scientific Review Officer, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 5194, MSC 7846, Bethesda, MD 20892, (301) 408–9756, *carsteae@csr.nih.gov.*

Name of Committee: Center for Scientific Review Special Emphasis Panel; Member Conflict: Mechanisms of Neurodegeneration and Neuropathology.

Date: November 20, 2015.

Time: 1:00 p.m. to 4:00 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: Linda MacArthur, Ph.D., Scientific Review Officer, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 4187, Bethesda, MD 20892, 301–537–9986, *macarthurlh@csr.nih.gov.*

Name of Committee: Center for Scientific Review Special Emphasis Panel; PAR–14–021 XSBR: X-ray Structural Biology Resource.

Date: November 22–24, 2015.

Time: 5:00 p.m. to 3:00 p.m.

Agenda: To review and evaluate grant applications.

Place: The Hotel Shattuck Plaza, 2086 Allston Way, Berkeley, CA 94704.

Contact Person: Nuria E. Assa-Munt, Ph.D., Scientific Review Officer, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 4164, MSC 7806, Bethesda, MD 20892, (301) 451–1323, *assamunu@csr.nih.gov.*

Name of Committee: Center for Scientific Review Special Emphasis Panel; Member Conflict: Child Psychopathology and Developmental Disorders AREA Review.

Date: November 23, 2015.

Time: 11:00 a.m. to 1:00 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: Serena Chu, Ph.D., Scientific Review Officer, BBBP IRG, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 3178, MSC 7848, Bethesda, MD 20892, 301–500–5829, *sechu@csr.nih.gov.*

Name of Committee: Center for Scientific Review Special Emphasis Panel; Member Conflicts: Gastrointestinal Pathobiology.

Date: November 23, 2015.

Time: 1:00 p.m. to 4:00 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: Atul Sahai, Ph.D., Scientific Review Officer, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 2188, MSC 7818, Bethesda, MD 20892, 301–435–1198, *sahaia@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: October 19, 2015.

Melanie J. Gray,

Program Analyst, Office of Federal Advisory Committee Policy.

[FR Doc. 2015–26927 Filed 10–22–15; 8:45 am]

BILLING CODE 4140–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

Eunice Kennedy Shriver National Institute of Child Health and Human Development; Notice of Meeting

Pursuant to section 10(d) of the Federal Advisory Committee Act, as amended (5 U.S.C. App.), notice is hereby given of a meeting of the Board of Scientific Counselors, NICHD.

The meeting will be open to the public as indicated below, with the 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.

The meeting will be closed to the public as indicated below in accordance with the provisions set forth in section 552b(c)(6), Title 5 U.S.C., as amended for the review, discussion, and evaluation of individual intramural programs and projects conducted by the Eunice Kennedy Shriver National Institute of Child Health and Human Development, including consideration of personnel qualifications and performance, and the competence of individual investigators, the disclosure of which would constitute a clearly unwarranted invasion of personal privacy.

Name of Committee: Board of Scientific Counselors, NICHD.

Date: December 4, 2015.

Open: 8:00 a.m. to 12:15 p.m.

Agenda: A report by the Scientific Director, NICHD, on the status of the NICHD Division of Intramural Research, talks by various intramural scientists, and proposed organizational change.

Place: National Institutes of Health, Building 31A, Conference Room 2A48, 31 Center Drive, Bethesda, MD 20892.

Closed: 12:15 p.m. to 4:00 p.m.

Agenda: To review and evaluate personal qualifications and performance, and competence of individual investigators.

Place: National Institutes of Health, Building 31A, Conference Room 2A48, 31 Center Drive, Bethesda, MD 20892.

Contact Person: Constantine A. Staratakis, MD, D(med)Sci Scientific Director, Eunice Kennedy Shriver National Institute of Child Health and Human Development, NIH, Building 31A, Room 2A46, 31 Center Drive, Bethesda, MD 20892, 301–594–5984, *stratakc@mail.nih.gov.*

Information is also available on the Institute's/Center's home page: *http://dir.nichd.nih.gov/dirweb/home.html,* where an agenda and any additional information for the meeting will be posted when available.

(Catalogue of Federal Domestic Assistance Program Nos.93.864, Population Research; 93.865, Research for Mothers and Children; 93.929, Center for Medical Rehabilitation Research; 93.209, Contraception and Infertility Loan Repayment Program, National Institutes of Health, HHS)

Dated: October 19, 2015.

Michelle Trout,

Program Analyst, Office of Federal Advisory Committee Policy.

[FR Doc. 2015–26928 Filed 10–22–15; 8:45 am]

BILLING CODE 4140–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

National Institute on Drug Abuse; 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 materials, 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 Drug Abuse Special Emphasis Panel NIH Pathway to Independence Award (K99/R00).

Date: November 12, 2015.

Time: 8:00 a.m. to 5:00 p.m.

Agenda: To review and evaluate grant applications.

Place: Hilton Garden Inn Bethesda, 7301 Waverly Street, Bethesda, MD 20814.

Contact Person: Susan O. McGuire, Ph.D., Scientific Review Officer, Office of Extramural Affairs, National Institute on Drug Abuse, National Institutes of Health, DHHS, 6001 Executive Blvd., Room 4245, Rockville, MD 20852, 301–435–1426, *mcguireso@mail.nih.gov.*

Name of Committee: National Institute on Drug Abuse Special Emphasis Panel (T32) Ruth L. Kirschstein National Research Service Award (NRSA) Institutional Research Training Grants.

Date: November 13, 2015.

Time: 8:00 a.m. to 5:00 p.m.

Agenda: To review and evaluate grant applications.

Place: Hilton Garden Inn Bethesda, 7301 Waverly Street, Bethesda, MD 20814.

Contact Person: Susan O. McGuire, Ph.D., Scientific Review Officer, Office of Extramural Affairs, National Institute on Drug Abuse, National Institutes of Health, DHHS, 6001 Executive Blvd., Room 4245, Rockville, MD 20852, 301–435–1426, *mcguireso@mail.nih.gov.*

Name of Committee: National Institute on Drug Abuse Special Emphasis Panel NIDA Mentored Clinical Scientists Development Program Award in Drug Abuse and Addiction (K12).

Date: November 13, 2015.

Time: 8:00 a.m. to 9:00 a.m.

Agenda: To review and evaluate grant applications.

Place: Hilton Garden Inn Bethesda, 7301 Waverly Street, Bethesda, MD 20814.

Contact Person: Susan O. McGuire, Ph.D., Scientific Review Officer, Office of Extramural Affairs, National Institute on Drug Abuse, National Institutes of Health, DHHS, 6001 Executive Blvd., Room 4245, Rockville, MD 20852, 301–435–1426, *mcguireso@mail.nih.gov.*

Name of Committee: National Institute on Drug Abuse Special Emphasis Panel Exploratory Studies of Smoking Cessation Interventions for People with Schizophrenia (R21/R33).

Date: November 13, 2015.

Time: 1:00 p.m. to 5:00 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: Jose F. Ruiz, Ph.D., Scientific Review Officer, Office of Extramural Affairs, National Institute on Drug Abuse, NIH, Room 4228, MSC 9550, 6001 Executive Blvd., Bethesda, MD 20892–9550, (301) 451–3086, *ruizjf@nida.nih.gov.*

(Catalogue of Federal Domestic Assistance Program Nos.: 93.279, Drug Abuse and Addiction Research Programs, National Institutes of Health, HHS)

Dated: October 19, 2015.

Natasha Copeland,

Program Analyst, Office of Federal Advisory Committee Policy.

[FR Doc. 2015–26929 Filed 10–22–15; 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; Lifespan Human Connectome Project: Development (U01).

Date: November 6, 2015.

Time: 4:00 p.m. to 5:00 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: Rebecca Steiner Garcia, Ph.D., Scientific Review Officer, Division of Extramural Activities, National Institute of Mental Health, NIH, Neuroscience Center, 6001 Executive Blvd., Room 6149, MSC 9608, Bethesda, MD 20892–9608, 301–443–4525, *steinerr@mail.nih.gov.*

Name of Committee: National Institute of Mental Health Special Emphasis Panel; Silvio O. Conte Centers for Basic or Translational Mental Health Research.

Date: November 10, 2015.

Time: 8:00 a.m. to 5:00 p.m.

Agenda: To review and evaluate grant applications.

Place: The Dupont Hotel, 1500 New Hampshire Avenue NW., Washington, DC 20036.

Contact Person: Megan Kinnane, Ph.D., Scientific Review Officer, Division of Extramural Activities, National Institute of Mental Health, NIH, Neuroscience Center, 6001 Executive Blvd., Room 6148, MSC 9609, Rockville, MD 20852–9609, 301–402–6807, *libbeym@mail.nih.gov.*

Name of Committee: National Institute of Mental Health Special Emphasis Panel; National Cooperative Drug Discovery/Development Groups (NCDDG) and National Cooperative Reprogrammed Cell Research Groups (NCRCRG).

Date: November 12, 2015.

Time: 12:00 p.m. to 2:00 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: Vinod Charles, Ph.D., Scientific Review Officer, Division of Extramural Activities, National Institute of Mental Health, NIH, Neuroscience Center, 6001 Executive Blvd., Room 6151, MSC 9606, Bethesda, MD 20892–9606, 301–443–1606, *charlesvi@mail.nih.gov.*

(Catalogue of Federal Domestic Assistance Program No. 93.242, Mental Health Research Grants, National Institutes of Health, HHS)

Dated: October 19, 2015.

Carolyn A. Baum,

Program Analyst, Office of Federal Advisory Committee Policy.

[FR Doc. 2015–26932 Filed 10–22–15; 8:45 am]

BILLING CODE 4140–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

National Institute of Allergy and Infectious Diseases; 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 Allergy and Infectious Diseases Special Emphasis Panel; AIDSRRC Independent SEP.

Date: November 18, 2015.

Time: 2:30 p.m. to 4:00 p.m.

Agenda: To review and evaluate grant applications.

Place: National Institutes of Health, Room 3C100, 5601 Fishers Lane, Rockville, MD 20892 (Telephone Conference Call).

Contact Person: Frank S. De Silva, Ph.D., Scientific Review Officer, Scientific Review Program, Division of Extramural Activities, Room #3E72A, National Institutes of Health/NIAID, 5601 Fishers Lane, MSC 9823, Bethesda, MD 20892–9823, (240) 669–5023, *fdesilva@niaid.nih.gov.*

Name of Committee: National Institute of Allergy and Infectious Diseases Special Emphasis Panel; Molecular Mechanisms of Combination Adjuvants (MMCA) (U01).

Date: November 19–20, 2015.

Time: 8:00 a.m. to 6:00 p.m.

Agenda: To review and evaluate grant applications.

Place: Bethesda North Marriott Hotel & Conference Center, Room Brookside A & B, 5701 Marinelli Road, Bethesda, MD 20852.

Contact Person: Lakshmi Ramachandra, Ph.D., Scientific Review Officer, Scientific Review Program, Division of Extramural Activities, RM 3G33, National Institutes of Health, NIAID, 5601 Fishers Lane, MSC 9823, Bethesda, MD 20892–9823, (240) 669–5061, *Ramachandral@niaid.nih.gov.*

(Catalogue of Federal Domestic Assistance Program Nos. 93.855, Allergy, Immunology, and Transplantation Research; 93.856, Microbiology and Infectious Diseases Research, National Institutes of Health, HHS)

Dated: *October 19, 2015.*

Natasha Copeland,

Program Analyst, Office of Federal Advisory Committee Policy.

[FR Doc. 2015–26931 Filed 10–22–15; 8:45 am]

BILLING CODE 4140–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

National Institute on Drug Abuse; 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 contract proposals and the discussions could disclose confidential trade secrets or commercial property such as patentable material, and personal information concerning individuals associated with the contract proposals, the disclosure of which would constitute a clearly unwarranted invasion of personal privacy.

Name of Committee: National Institute on Drug Abuse Special Emphasis Panel; SBIR Phase II: ACA Web Platform/Behavioral (5580).

Date: December 3, 2015.

Time: 10:00 a.m. to 12:00 p.m.

Agenda: To review and evaluate contract proposals.

Place: National Institutes of Health, Neuroscience Center, 6001 Executive Boulevard, Rockville, MD 20852 (Telephone Conference Call).

Contact Person: Lyle Furr, Scientific Review Officer, Office of Extramural Affairs, National Institute on Drug Abuse, NIH, DHHS, Room 4227, MSC 9550, 6001 Executive Boulevard, Bethesda, MD 20892–9550, (301) 435–1439, *lf33c.nih.gov.*

(Catalogue of Federal Domestic Assistance Program No.: 93.279, Drug Abuse and Addiction Research Programs, National Institutes of Health, HHS)

Dated: October 19, 2015.

Natasha M. Copeland,

Program Analyst, Office of Federal Advisory Committee Policy.

[FR Doc. 2015–26930 Filed 10–22–15; 8:45 am]

BILLING CODE 4140–01–P

DEPARTMENT OF HOMELAND SECURITY

Coast Guard

[Docket No. USCG–2015–0909]

Information Collection Request to Office of Management and Budget; OMB Control Number: 1625–0039

AGENCY: Coast Guard, DHS.

ACTION: Sixty-day notice requesting comments.

SUMMARY: In compliance with the Paperwork Reduction Act of 1995, the

U.S. Coast Guard intends to submit an Information Collection Request (ICR) to the Office of Management and Budget (OMB), Office of Information and Regulatory Affairs (OIRA), requesting approval of revisions to the following collection of information: 1625–0039, Declaration of Inspection Before Transfer of Liquid in Bulk. Our ICR[s] describe[s] the information we seek to collect from the public. Before submitting this ICR to OIRA, the Coast Guard is inviting comments as described below.

DATES: Comments must reach the Coast Guard on or before December 22, 2015.

ADDRESSES: You may submit comments identified by Coast Guard docket number [USCG–2015–0909] to the Coast Guard using the Federal eRulemaking Portal at *http://www.regulations.gov.* See the ''Public participation and request for comments'' portion of the **SUPPLEMENTARY INFORMATION** section for further instructions on submitting comments.

A copy of the ICR is available through the docket on the Internet at *http://www.regulations.gov.* Additionally, copies are available from: COMMANDANT (CG–612), ATTN: PAPERWORK REDUCTION ACT MANAGER, U.S. COAST GUARD, 2703 MARTIN LUTHER KING JR AVE SE., STOP 7710, WASHINGTON, DC 20593–7710.

FOR FURTHER INFORMATION CONTACT: Mr. Anthony Smith, Office of Information Management, telephone 202–475–3532, or fax 202–372–8405, for questions on these documents.

SUPPLEMENTARY INFORMATION:

Public Participation and Request for Comments

This Notice relies on the authority of the Paperwork Reduction Act of 1995; 44 U.S.C. Chapter 35, as amended. An ICR is an application to OIRA seeking the approval, extension, or renewal of a Coast Guard collection of information (Collection). The ICR contains information describing the Collection's purpose, the Collection's likely burden on the affected public, an explanation of the necessity of the Collection, and other important information describing the Collection. There is one ICR for each Collection.

The Coast Guard invites comments on whether this ICR should be granted based on the Collection being necessary for the proper performance of Departmental functions. In particular, the Coast Guard would appreciate comments addressing: (1) The practical utility of the Collection; (2) the accuracy of the estimated burden of the Collection; (3) ways to enhance the quality, utility, and clarity of information subject to the Collection; and (4) ways to minimize the burden of the Collection on respondents, including the use of automated collection techniques or other forms of information technology. In response to your comments, we may revise this ICR or decide not to seek approval of revisions of the Collection. We will consider all comments and material received during the comment period.

We encourage you to respond to this request by submitting comments and related materials. Comments must contain the OMB Control Number of the ICR and the docket number of this request, [USCG–2015–0909], and must be received by December 22, 2015.

Submitting Comments

We encourage you to submit comments through the Federal eRulemaking Portal at *http://www.regulations.gov.* If your material cannot be submitted using *http://www.regulations.gov,* contact the person in the **FOR FURTHER INFORMATION CONTACT** section of this document for alternate instructions. Documents mentioned in this notice, and all public comments, are in our online docket at *http://www.regulations.gov* and can be viewed by following that Web site's instructions. Additionally, if you go to the online docket and sign up for email alerts, you will be notified when comments are posted.

We accept anonymous comments. All comments received will be posted without change to *http://www.regulations.gov* and will include any personal information you have provided. For more about privacy and the docket, you may review a Privacy Act notice regarding the Federal Docket Management System in the March 24, 2005, issue of the **Federal Register** (70 FR 15086).

Information Collection Request

1. *Title:* Declaration of Inspection Before Transfer of Liquid in Bulk.

OMB Control Number: 1625–0039.

Summary: A Declaration of Inspection (DOI) documents the transfer of oil and hazardous materials, to help prevent spills and damage to a facility or vessel. Persons-in-charge of the transfer operations must review and certify compliance with procedures specified by the terms of the DOI.

Need: Title 33 U.S.C. 1321(j) authorizes the Coast Guard to established regulations to prevent the discharge of oil and hazardous material from vessels and facilities. The DOI regulations appear at 33 CFR 156.150 and 46 CFR 35.35–30.

Respondents: Persons-in-charge of transfers.

Frequency: On occasion.

Hour Burden Estimate: The estimated burden has increased from 62,514 hours to 77,973 hours a year due to an increase in the estimated annual number of responses.

Authority: The Paperwork Reduction Act of 1995; 44 U.S.C. Chapter 35, as amended.

Dated: October 18, 2015.

Thomas P. Michelli,

U.S. Coast Guard, Deputy Chief Information Officer.

[FR Doc. 2015–27016 Filed 10–22–15; 8:45 am]

BILLING CODE 9110–04–P

DEPARTMENT OF HOMELAND SECURITY

Coast Guard

[Docket No. USCG–2015–0910]

Information Collection Request to Office of Management and Budget; OMB Control Number: 1625–0001

AGENCY: Coast Guard, DHS.

ACTION: Sixty-day notice requesting comments.

SUMMARY: In compliance with the Paperwork Reduction Act of 1995, the U.S. Coast Guard intends to submit an Information Collection Request (ICR) to the Office of Management and Budget (OMB), Office of Information and Regulatory Affairs (OIRA), requesting approval of revisions to the following collection of information: 1625–0001, Marine Casualty Information & Periodic Chemical Drug and Alcohol Testing of Commercial Vessel Personnel. Our ICR describe the information we seek to collect from the public. Before submitting this ICR to OIRA, the Coast Guard is inviting comments as described below.

DATES: Comments must reach the Coast Guard on or before December 22, 2015.

ADDRESSES: You may submit comments identified by Coast Guard docket number [USCG–2015–0910] to the Coast Guard using the Federal eRulemaking Portal at *http://www.regulations.gov*. See the ''Public participation and request for comments'' portion of the **SUPPLEMENTARY INFORMATION** section for further instructions on submitting comments.

A copy of the ICR is available through the docket on the Internet at *http://www.regulations.gov*. Additionally, copies are available from: COMMANDANT (CG–612), ATTN:

PAPERWORK REDUCTION ACT MANAGER, U.S. COAST GUARD, 2703 MARTIN LUTHER KING JR AVE SE., STOP 7710, WASHINGTON, DC 20593–7710.

FOR FURTHER INFORMATION CONTACT: Mr. Anthony Smith, Office of Information Management, telephone 202–475–3532, or fax 202–372–8405, for questions on these documents.

SUPPLEMENTARY INFORMATION:

Public Participation and Request for Comments

This Notice relies on the authority of the Paperwork Reduction Act of 1995; 44 U.S.C. Chapter 35, as amended. An ICR is an application to OIRA seeking the approval, extension, or renewal of a Coast Guard collection of information (Collection). The ICR contains information describing the Collection's purpose, the Collection's likely burden on the affected public, an explanation of the necessity of the Collection, and other important information describing the Collection. There is one ICR for each Collection.

The Coast Guard invites comments on whether this ICR should be granted based on the Collection being necessary for the proper performance of Departmental functions. In particular, the Coast Guard would appreciate comments addressing: (1) The practical utility of the Collection; (2) the accuracy of the estimated burden of the Collection; (3) ways to enhance the quality, utility, and clarity of information subject to the Collection; and (4) ways to minimize the burden of the Collection on respondents, including the use of automated collection techniques or other forms of information technology. In response to your comments, we may revise this ICR or decide not to seek approval of revisions of the Collection. We will consider all comments and material received during the comment period.

We encourage you to respond to this request by submitting comments and related materials. Comments must contain the OMB Control Number of the ICR and the docket number of this request, [USCG–2015–0910], and must be received by December 22, 2015.

Submitting Comments

We encourage you to submit comments through the Federal eRulemaking Portal at *http://www.regulations.gov*. If your material cannot be submitted using *http://www.regulations.gov,* contact the person in the **FOR FURTHER INFORMATION CONTACT** section of this document for alternate instructions. Documents mentioned in this notice, and all public comments, are in our online docket at *http://www.regulations.gov* and can be viewed by following that Web site's instructions. Additionally, if you go to the online docket and sign up for email alerts, you will be notified when comments are posted.

We accept anonymous comments. All comments received will be posted without change to *http://www.regulations.gov* and will include any personal information you have provided. For more about privacy and the docket, you may review a Privacy Act notice regarding the Federal Docket Management System in the March 24, 2005, issue of the **Federal Register** (70 FR 15086).

Information Collection Request

1. *Title:* Marine Casualty Information & Periodic Chemical Drug and Alcohol Testing of Commercial Vessel Personnel.

OMB Control Number: 1625–0001.

Summary: Marine casualty information is needed for Coast Guard investigations of commercial vessel casualties involving death, vessel damage, etc., as mandated by Congress. Chemical testing information is needed to improve CG detection/reduction of drug use by mariners.

Need: Section 6101 of 46 U.S.C., as delegated by the Secretary of Homeland Security to the Commandant, authorizes the Coast Guard to prescribe regulations for the reporting of marine casualties involving death, serious injury, material loss of property, material damage affecting the seaworthiness of a vessel, or significant harm to the environment. It also requires information on the use of alcohol being included in a marine casualty report. Section 7503 of 46 U.S.C. authorizes the Coast Guard to deny the issuance of licenses, certificates of registry, and merchant mariner's documents (seaman's papers) to users of dangerous drugs. Similarly, 46 U.S.C. 7704 requires the Coast Guard to revoke such papers unless a holder provides satisfactory proofs that the holder is cured.

Forms: CG–2692, Report of Marine Casualty, Commercial Diving Casualty, or OCS-related Casualty; CG–2692A, Barge Addendum; CG–2692B, Report of Mandatory Chemical Testing Following a Serious Marine Incident Involving Vessels in Commercial Service; CG–2692C, Personnel Casualty Addendum; CG–2692D, Involved Persons and Witnesses Addendum.

Why Is The Coast Guard Proposing To Add 2 New Forms: The Coast Guard recently reviewed its regulations and policies with respect to the marine casualty reporting requirements found in 46 CFR part 4. During this project, an evaluation of comments and feedback from the maritime industry and general public, as well as an internal assessment of current statutory and regulatory requirements and Coast Guard policies, identified the need to revise the form used by the public to submit written reports of marine casualties, the form CG–2692 (currently titled Report of Marine Accident, Injury or Death) and its Addendum forms.

The resulting proposal to revise these forms, which includes revising the title name of the form and taking certain sections of the CG–2692 and moving them to two new Addendum forms (facilitates multiple entry capability not currently available) have been drafted with the following goals in mind:

- Reduce the overall amount of information required to be entered to submit reports for marine casualties while still meeting all statutory and regulatory requirements.
- Clarify what types of incidents require the submission of the written report and seek the inclusion of additional information, entered on one or more of the Addendum forms, only when it is necessary.
- Reformat and organize the information on the forms such that it is more adaptable to the development of an alternate electronic means of submission.

Respondents: Vessel owners and operators.

Frequency: On occasion.

Hour Burden Estimate: The estimated burden has increased from 20,986 hours to 23,586 hours a year due to an increase in the estimated number of responses.

Authority: The Paperwork Reduction Act of 1995; 44 U.S.C. Chapter 35, as amended.

Dated: October 18, 2015.

Thomas P. Michelli,

U.S. Coast Guard, Deputy Chief Information Officer.

[FR Doc. 2015–27019 Filed 10–22–15; 8:45 am]

BILLING CODE 9110–04–P

DEPARTMENT OF HOMELAND SECURITY

Coast Guard

[Docket No. USCG–2015–0630]

Collection of Information Under Review by Office of Management and Budget; OMB Control Number: 1625–0035

AGENCY: Coast Guard, DHS.

ACTION: Thirty-day notice requesting comments.

SUMMARY: In compliance with the Paperwork Reduction Act of 1995 the U.S. Coast Guard is forwarding an Information Collection Request (ICR), abstracted below, to the Office of Management and Budget (OMB), Office of Information and Regulatory Affairs (OIRA), requesting approval of a revision to the following collection of information: 1625–0035, Title 46 CFR Subchapter Q: Lifesaving, Electrical, Engineering and Navigation Equipment, Construction and Materials & Marine Sanitation Devices (33 CFR part 159). Our ICR describe the information we seek to collect from the public. Review and comments by OIRA ensure we only impose paperwork burdens commensurate with our performance of duties.

DATES: Comments must reach the Coast Guard and OIRA on or before November 23, 2015.

ADDRESSES: You may submit comments identified by Coast Guard docket number [USCG–2015–0630] to the Coast Guard using the Federal eRulemaking Portal at *http://www.regulations.gov.* Alternatively, you may submit comments to OIRA using one of the following means:

(1) *Email: OIRA-submission@omb.eop.gov.*

(2) *Mail:* OIRA, 725 17th Street NW., Washington, DC 20503, attention Desk Officer for the Coast Guard.

(3) *Fax:* 202–395–6566. To ensure your comments are received in a timely manner, mark the fax, attention Desk Officer for the Coast Guard.

A copy of the ICR is available through the docket on the Internet at *http://www.regulations.gov.* Additionally, copies are available from: COMMANDANT (CG–612), ATTN: PAPERWORK REDUCTION ACT MANAGER, U.S. COAST GUARD, 2703 MARTIN LUTHER KING JR AVE SE., STOP 7710, WASHINGTON, DC 20593–7710.

FOR FURTHER INFORMATION CONTACT: Mr. Anthony Smith, Office of Information Management, telephone 202–475–3532, or fax 202–372–8405, for questions on these documents.

SUPPLEMENTARY INFORMATION:

Public Participation and Request for Comments

This Notice relies on the authority of the Paperwork Reduction Act of 1995; 44 U.S.C. Chapter 35, as amended. An ICR is an application to OIRA seeking the approval, extension, or renewal of a Coast Guard collection of information (Collection). The ICR contains information describing the Collection's purpose, the Collection's likely burden on the affected public, an explanation of the necessity of the Collection, and other important information describing the Collection. There is one ICR for each Collection. The Coast Guard invites comments on whether this ICR should be granted based on the Collection being necessary for the proper performance of Departmental functions. In particular, the Coast Guard would appreciate comments addressing: (1) The practical utility of the Collection; (2) the accuracy of the estimated burden of the Collection; (3) ways to enhance the quality, utility, and clarity of information subject to the Collection; and (4) ways to minimize the burden of the Collection on respondents, including the use of automated collection techniques or other forms of information technology. These comments will help OIRA determine whether to approve the ICR referred to in this Notice.

We encourage you to respond to this request by submitting comments and related materials. Comments to Coast Guard or OIRA must contain the OMB Control Number of the ICR. They must also contain the docket number of this request, [USCG–2015–0630], and must be received by November 23, 2015.

Submitting Comments

We encourage you to submit comments through the Federal eRulemaking Portal at *http://www.regulations.gov.* If your material cannot be submitted using *http://www.regulations.gov,* contact the person in the **FOR FURTHER INFORMATION CONTACT** section of this document for alternate instructions. Documents mentioned in this notice, and all public comments, are in our online docket at *http://www.regulations.gov* and can be viewed by following that Web site's instructions. Additionally, if you go to the online docket and sign up for email alerts, you will be notified when comments are posted.

We accept anonymous comments. All comments received will be posted without change to *http://www.regulations.gov* and will include any personal information you have provided. For more about privacy and the docket, you may review a Privacy Act notice regarding the Federal Docket Management System in the March 24, 2005, issue of the **Federal Register** (70 FR 15086).

OIRA posts its decisions on ICRs online at *http://www.reginfo.gov/public/do/PRAMain* after the comment period for each ICR. An OMB Notice of Action on each ICR will become available via a hyperlink in the OMB Control Number: 1625–0035.

Previous Request for Comments

This request provides a 30-day comment period required by OIRA. The Coast Guard has published the 60-day notice (80 FR 45671, July 31, 2015) required by 44 U.S.C. 3506(c)(2). That Notice elicited no comments. Accordingly, no changes have been made to the Collections.

Information Collection Request

1. *Title:* Title 46 CFR Subchapter Q: Lifesaving, Electrical, Engineering and Navigation Equipment, Construction and Materials & Marine Sanitation Devices (33 CFR part 159).

OMB Control Number: 1625–0035.

Summary: This information is used by the Coast Guard to ensure that regulations governing specific types of safety equipment, material and Marine Sanitation Devices (MSDs) installed on commercial vessels and pleasure craft are met. Manufacturers are required to submit drawings, specifications, and laboratory test reports to the Coast Guard before any approval is given.

Need: Title 46 U.S.C. 2103, 3306, 3703, and 4302 authorize the Coast Guard to establish safety equipment and material regulations. Title 46 CFR parts 159 to 164 prescribe these requirements. Title 33 U.S.C. 1322 authorizes the Coast Guard to establish MSD regulations. Title 33 CFR part 159 prescribes these rules. NVIC 8–01 (Chg 2) prescribes the standards for navigation equipment. This information is used to determine whether manufacturers are in compliance with Coast Guard regulations. When the Coast Guard approves any safety equipment, material or MSD for use on a commercial vessel or pleasure craft, the manufacturer is issued a Certificate of Approval.

Respondents: Manufacturers of safety equipment, materials and marine sanitation devices.

Forms: CG–10030, Certificate of Approval.

Frequency: On occasion.

Hour Burden Estimate: The estimated burden has increased from 58,414 hours to 118,594 hours a year due to an increase in the estimated annual number of responses.

Authority: The Paperwork Reduction Act of 1995; 44 U.S.C. Chapter 35, as amended.

Dated: October 18, 2015.

Thomas P. Michelli,

U.S. Coast Guard, Deputy Chief Information Officer.

[FR Doc. 2015–27018 Filed 10–22–15; 8:45 am]

BILLING CODE 9110–04–P

DEPARTMENT OF HOMELAND SECURITY

Coast Guard

[Docket No. USCG–2015–0475]

Collection of Information Under Review by Office of Management and Budget; OMB Control Number: 1625–0095

AGENCY: Coast Guard, DHS.

ACTION: Thirty-day notice requesting comments.

SUMMARY: In compliance with the Paperwork Reduction Act of 1995 the U.S. Coast Guard is forwarding an Information Collection Request (ICR), abstracted below, to the Office of Management and Budget (OMB), Office of Information and Regulatory Affairs (OIRA), requesting an extension of its approval for the following collection of information: 1625–0095, Oil and Hazardous Material Pollution Prevention and Safety Records, Equivalents/Alternatives and Exemptions without change.

Our ICR describe the information we seek to collect from the public. Review and comments by OIRA ensure we only impose paperwork burdens commensurate with our performance of duties.

DATES: Comments must reach the Coast Guard and OIRA on or before November 23, 2015.

ADDRESSES: You may submit comments identified by Coast Guard docket number [USCG–2015–0475] to the Coast Guard using the Federal eRulemaking Portal at *http://www.regulations.gov.* Alternatively, you may submit comments to OIRA using one of the following means:

(1) *Email: OIRA-submission@omb.eop.gov.*

(2) *Mail:* OIRA, 725 17th Street NW., Washington, DC 20503, attention Desk Officer for the Coast Guard.

(3) *Fax:* 202–395–6566. To ensure your comments are received in a timely manner, mark the fax, attention Desk Officer for the Coast Guard.

A copy of the ICR is available through the docket on the Internet at *http://www.regulations.gov.* Additionally, copies are available from: COMMANDANT (CG–612), ATTN: PAPERWORK REDUCTION ACT MANAGER, U.S. COAST GUARD, 2100 2ND STREET SW., STOP 7710, WASHINGTON, DC 20593–7710.

FOR FURTHER INFORMATION CONTACT: Contact Mr. Anthony Smith, Office of Information Management, telephone 202–475–3532, or fax 202–372–8405, for questions on these documents.

SUPPLEMENTARY INFORMATION:

Public Participation and Request for Comments

This Notice relies on the authority of the Paperwork Reduction Act of 1995; 44 U.S.C. chapter 35, as amended. An ICR is an application to OIRA seeking the approval, extension, or renewal of a Coast Guard collection of information (Collection). The ICR contains information describing the Collection's purpose, the Collection's likely burden on the affected public, an explanation of the necessity of the Collection, and other important information describing the Collection. There is one ICR for each Collection. The Coast Guard invites comments on whether this ICR should be granted based on the Collection being necessary for the proper performance of Departmental functions. In particular, the Coast Guard would appreciate comments addressing: (1) The practical utility of the Collection; (2) the accuracy of the estimated burden of the Collection; (3) ways to enhance the quality, utility, and clarity of information subject to the Collection; and (4) ways to minimize the burden of the Collection on respondents, including the use of automated collection techniques or other forms of information technology. These comments will help OIRA determine whether to approve the ICR referred to in this Notice.

We encourage you to respond to this request by submitting comments and related materials. Comments to Coast Guard or OIRA must contain the OMB Control Number of the ICR. They must also contain the docket number of this request, [USCG–2015–0475], and must be received by November 23, 2015.

Submitting Comments

We encourage you to submit comments through the Federal eRulemaking Portal at *http://www.regulations.gov.* If your material cannot be submitted using *http://www.regulations.gov,* contact the person in the **FOR FURTHER INFORMATION CONTACT** section of this document for alternate instructions. Documents mentioned in this notice, and all public comments, are in our online docket at *http://www.regulations.gov* and can be viewed by following that Web site's instructions. Additionally, if you go to the online docket and sign up for email alerts, you will be notified when comments are posted.

We accept anonymous comments. All comments received will be posted without change to *http://www.regulations.gov* and will include any personal information you have provided. For more about privacy and the docket, you may review a Privacy Act notice regarding the Federal Docket Management System in the March 24, 2005 issue of the **Federal Register** (70 FR 15086).

OIRA posts its decisions on ICRs online at *http://www.reginfo.gov/public/do/PRAMain* after the comment period for each ICR. An OMB Notice of Action on each ICR will become available via a hyperlink in the OMB Control Number: 1625–0095.

Previous Request for Comments

This request provides a 30-day comment period required by OIRA. The Coast Guard published the 60-day notice (80 FR 45666, July 31, 2015) required by 44 U.S.C. 3506(c)(2). That Notice elicited no comments. Accordingly, no changes have been made to the Collections.

Information Collection Request

1. *Title:* Oil and Hazardous Material Pollution Prevention and Safety Records, Equivalents/Alternatives and Exemptions.

OMB Control Number: 1625–0095.

Summary: The information is used by the Coast Guard to ensure that an oil or hazardous material requirement alternative or exemption provides an equivalent level of safety and protection from pollution.

Need: Under 33 U.S.C. 1321 and Executive Order 12777 the Coast Guard is authorized to prescribe regulations to prevent the discharge of oil and hazardous substances from vessels and facilities and to contain such discharges. Coast Guard regulations in 33 CFR parts 154–156 are intended to: (1) Prevent or mitigate the results of an accidental release of bulk liquid hazardous materials being transferred at waterfront facilities; (2) ensure that facilities and vessels that use vapor control systems are in compliance with the safety standards developed by the Coast Guard; (3) provide equipment and operational requirements for facilities and vessels that transfer oil or hazardous materials in bulk to or from vessels with a 250 or more barrel capacity; (4) provide procedures for vessel or facility operators who request exemption or partial exemption from the requirements of the pollution prevention regulations.

Forms: N/A.

Respondents: Owners and operators of bulk oil and hazardous materials facilities and vessels. The estimated number of respondents is 180.

Frequency: On occasion.

Hour Burden Estimate: The estimated annual burden remains 1,440 hours a year.

Authority: The Paperwork Reduction Act of 1995; 44 U.S.C. chapter 35, as amended.

Dated: October 18, 2015.

Thomas P. Michelli,

U.S. Coast Guard, Deputy Chief Information Officer.

[FR Doc. 2015–27041 Filed 10–22–15; 8:45 am]

BILLING CODE 9110–04–P

DEPARTMENT OF HOMELAND SECURITY

Coast Guard

[Docket No. USCG–2015–0755]

Information Collection Request to Office of Management and Budget; OMB Control Number: 1625–0016

AGENCY: Coast Guard, DHS.

ACTION: Sixty-day notice requesting comments.

SUMMARY: In compliance with the Paperwork Reduction Act of 1995, the U.S. Coast Guard intends to submit an Information Collection Request (ICR) to the Office of Management and Budget (OMB), Office of Information and Regulatory Affairs (OIRA), requesting approval of revisions to the following collection of information: 1625–0016, Welding and Hot Works Permits; Posting of Warning Signs. Our ICR describe the information we seek to collect from the public. Before submitting this ICR to OIRA, the Coast Guard is inviting comments as described below.

DATES: Comments must reach the Coast Guard on or before December 22, 2015.

ADDRESSES: You may submit comments identified by Coast Guard docket number [USCG–2015–0755] to the Coast Guard using the Federal eRulemaking Portal at *http://www.regulations.gov*. See the ''Public participation and request for comments'' portion of the SUPPLEMENTARY INFORMATION section for further instructions on submitting comments.

A copy of the ICR is available through the docket on the Internet at *http://www.regulations.gov*. Additionally, copies are available from: COMMANDANT (CG–612), ATTN: PAPERWORK REDUCTION ACT MANAGER, U.S. COAST GUARD, 2703 MARTIN LUTHER KING JR AVE SE., STOP 7710, WASHINGTON, DC 20593–7710.

FOR FURTHER INFORMATION CONTACT: Mr. Anthony Smith, Office of Information Management, telephone 202–475–3532, or fax 202–372–8405, for questions on these documents.

SUPPLEMENTARY INFORMATION:

Public Participation and Request for Comments

This Notice relies on the authority of the Paperwork Reduction Act of 1995; 44 U.S.C. Chapter 35, as amended. An ICR is an application to OIRA seeking the approval, extension, or renewal of a Coast Guard collection of information (Collection). The ICR contains information describing the Collection's purpose, the Collection's likely burden on the affected public, an explanation of the necessity of the Collection, and other important information describing the Collection. There is one ICR for each Collection.

The Coast Guard invites comments on whether this ICR should be granted based on the Collection being necessary for the proper performance of Departmental functions. In particular, the Coast Guard would appreciate comments addressing: (1) The practical utility of the Collection; (2) the accuracy of the estimated burden of the Collection; (3) ways to enhance the quality, utility, and clarity of information subject to the Collection; and (4) ways to minimize the burden of the Collection on respondents, including the use of automated collection techniques or other forms of information technology. In response to your comments, we may revise this ICR or decide not to seek approval of revisions of the Collection. We will consider all comments and material received during the comment period.

We encourage you to respond to this request by submitting comments and related materials. Comments must contain the OMB Control Number of the ICR and the docket number of this request, [USCG–2015–0755], and must be received by December 22, 2015.

Submitting Comments

We encourage you to submit comments through the Federal eRulemaking Portal at *http://www.regulations.gov*. If your material cannot be submitted using *http://www.regulations.gov,* contact the person in the FOR FURTHER INFORMATION CONTACT section of this document for alternate instructions. Documents mentioned in this notice, and all public comments, are in our online docket at *http://www.regulations.gov* and can be viewed by following that Web site's instructions. Additionally, if you go to the online docket and sign up for email alerts, you will be notified when comments are posted.

We accept anonymous comments. All comments received will be posted without change to *http://www.regulations.gov* and will include any personal information you have provided. For more about privacy and the docket, you may review a Privacy Act notice regarding the Federal Docket Management System in the March 24, 2005, issue of the **Federal Register** (70 FR 15086).

Information Collection Request

1. *Title:* Welding and Hot Works Permits; Posting of Warning Signs.

OMB Control Number: 1625–0016.

Summary: This information collection helps to ensure that waterfront facilities and vessels are in compliance with safety standards. A permit must be issued prior to welding or hot work at certain waterfront facilities; and, the posting of warning signs is required on certain facilities.

Need: The information is needed to ensure safe operations on certain waterfront facilities and vessels.

Forms: CG–4201, Welding and Hot Work.

Respondents: Owners and operators of certain waterfront facilities and vessels.

Frequency: On occasion.

Hour Burden Estimate: The estimated burden has increased from 546 hours to 593 hours a year due to an increase in the estimated annual number of responses.

Authority: The Paperwork Reduction Act of 1995; 44 U.S.C. Chapter 35, as amended.

Dated: October 18, 2015.

Thomas P. Michelli,

U.S. Coast Guard, Deputy Chief Information Officer.

[FR Doc. 2015–27020 Filed 10–22–15; 8:45 am]

BILLING CODE 9110–04–P

DEPARTMENT OF HOMELAND SECURITY

Coast Guard

[Docket No. USCG–2015–0634]

Collection of Information Under Review by Office of Management and Budget; OMB Control Number: 1625–0014

AGENCY: Coast Guard, DHS.

ACTION: Thirty-day notice requesting comments.

SUMMARY: In compliance with the Paperwork Reduction Act of 1995 the U.S. Coast Guard is forwarding an Information Collection Request (ICR), abstracted below, to the Office of Management and Budget (OMB), Office of Information and Regulatory Affairs (OIRA), requesting approval of a revision to the following collection of information: 1625–0014, Request for Designation and Exemption of Oceanographic Research Vessels. Our ICR describe the information we seek to collect from the public. Review and comments by OIRA ensure we only impose paperwork burdens commensurate with our performance of duties.

DATES: Comments must reach the Coast Guard and OIRA on or before November 23, 2015.

ADDRESSES: You may submit comments identified by Coast Guard docket number [USCG–2015–0634] to the Coast Guard using the Federal eRulemaking Portal at *http://www.regulations.gov.* Alternatively, you may submit comments to OIRA using one of the following means:

(1) *Email: OIRA-submission@omb.eop.gov.*

(2) *Mail:* OIRA, 725 17th Street NW., Washington, DC 20503, attention Desk Officer for the Coast Guard.

(3) *Fax:* 202–395–6566. To ensure your comments are received in a timely manner, mark the fax, attention Desk Officer for the Coast Guard.

A copy of the ICR is available through the docket on the Internet at *http://www.regulations.gov.* Additionally, copies are available from: COMMANDANT (CG–612), ATTN: PAPERWORK REDUCTION ACT MANAGER, U.S. COAST GUARD, 2703 MARTIN LUTHER KING JR. AVE. SE., STOP 7710, WASHINGTON, DC 20593–7710.

FOR FURTHER INFORMATION CONTACT: Contact Mr. Anthony Smith, Office of Information Management, telephone 202–475–3532, or fax 202–372–8405, for questions on these documents.

SUPPLEMENTARY INFORMATION:

Public Participation and Request for Comments

This Notice relies on the authority of the Paperwork Reduction Act of 1995; 44 U.S.C. Chapter 35, as amended. An ICR is an application to OIRA seeking the approval, extension, or renewal of a Coast Guard collection of information (Collection). The ICR contains information describing the Collection's purpose, the Collection's likely burden on the affected public, an explanation of the necessity of the Collection, and other important information describing the Collection. There is one ICR for each Collection. The Coast Guard invites comments on whether this ICR should be granted based on the Collection being necessary for the proper performance of Departmental functions. In particular, the Coast Guard would appreciate comments addressing: (1) The practical utility of the Collection; (2) the accuracy of the estimated burden of the Collection; (3) ways to enhance the quality, utility, and clarity of information subject to the Collection; and (4) ways to minimize the burden of the Collection on respondents, including the use of automated collection techniques or other forms of information technology. These comments will help OIRA determine whether to approve the ICR referred to in this Notice.

We encourage you to respond to this request by submitting comments and related materials. Comments to Coast Guard or OIRA must contain the OMB Control Number of the ICR. They must also contain the docket number of this request, [USCG–2015–0634], and must be received by November 23, 2015.

Submitting Comments

We encourage you to submit comments through the Federal eRulemaking Portal at *http://www.regulations.gov.* If your material cannot be submitted using *http://www.regulations.gov,* contact the person in the **FOR FURTHER INFORMATION CONTACT** section of this document for alternate instructions. Documents mentioned in this notice, and all public comments, are in our online docket at *http://www.regulations.gov* and can be viewed by following that Web site's instructions. Additionally, if you go to the online docket and sign up for email alerts, you will be notified when comments are posted.

We accept anonymous comments. All comments received will be posted without change to *http://www.regulations.gov* and will include any personal information you have provided. For more about privacy and the docket, you may review a Privacy Act notice regarding the Federal Docket Management System in the March 24, 2005, issue of the **Federal Register** (70 FR 15086).

OIRA posts its decisions on ICRs online at *http://www.reginfo.gov/public/do/PRAMain* after the comment period for each ICR. An OMB Notice of Action on each ICR will become available via a hyperlink in the OMB Control Number: 1625–0014 .

Previous Request for Comments

This request provides a 30-day comment period required by OIRA. The Coast Guard published the 60-day notice (80 FR 45669, July 31, 2015) required by 44 U.S.C. 3506(c)(2). That Notice elicited no comments. Accordingly, no changes have been made to the Collection.

Information Collection Request

1. *Title:* Request for Designation and Exemption of Oceanographic Research Vessels.

OMB Control Number: 1625–0014.

Summary: This collection requires submission of specific information about a vessel in order for the vessel to be designated as an Oceanographic Research Vessel (ORV).

Need: Title 46 U.S.C. 2113 authorizes the Secretary of the Department of Homeland Security to exempt Oceanographic Research Vessels (ORV), by regulation, from provisions of Subtitle II, of Title 46, Shipping, of the United States Code, concerning maritime safety and seaman's welfare laws. This information is necessary to ensure a vessel qualifies for the designation of ORV under 46 CFR part 3 and 46 CFR part 14, subpart D.

Forms: N/A.

Respondents: Owners or operators of certain vessel.

Frequency: On occasion.

Hour Burden Estimate: The estimated burden has decreased from 51 hours to 25 hours a year due to a decrease in the estimated annual number of respondents.

Authority: The Paperwork Reduction Act of 1995; 44 U.S.C. Chapter 35, as amended.

Dated: October 18, 2015.

Thomas P. Michelli,

U.S. Coast Guard, Deputy Chief Information Officer.

[FR Doc. 2015–27017 Filed 10–22–15; 8:45 am]

BILLING CODE 9110–04–P

DEPARTMENT OF HOMELAND SECURITY

Coast Guard

[Docket No. USCG–2010–0164]

National Boating Safety Advisory Council

AGENCY: Coast Guard, DHS.

ACTION: Notice of Federal Advisory Committee Meeting.

SUMMARY: The National Boating Safety Advisory Council and its

Subcommittees will meet on November 12 and 13, 2015, in Arlington, VA, to discuss issues relating to recreational boating safety. These meetings will be open to the public.

DATES: The National Boating Safety Advisory Council will meet Thursday, November 12, 2015, from 12:00 p.m. to 3:30 p.m. and Friday, November 13, 2015 from 1:30 p.m. to 4 p.m. The Boats and Associated Equipment Subcommittee will meet on November 12, 2015, from 3:30 p.m. to 5:15 p.m. The Prevention through People Subcommittee will meet on November 12, 2015, from 5:15 p.m. to 5:45 p.m. on November 12, 2015, and from 8:05 a.m. to 9:05 a.m. on November 13, 2015. The Recreational Boating Safety Strategic Planning Subcommittee will meet on November 13, 2015, from 9:05 a.m. to 12:00 p.m. Please note that these meetings may conclude early if the National Boating Safety Advisory Council has completed all business.

ADDRESSES: All meetings will be held in the Ballroom of the Holiday Inn Arlington (*http://www.hiarlington.com*), 4610 N. Fairfax Drive, Arlington, VA 22203.

For information on facilities or services for individuals with disabilities or to request special assistance at the meeting, contact Mr. Jeff Ludwig, Alternate Designated Federal Officer, telephone 202–372–1061, or at *jeffrey.a.ludwig@uscg.mil.*

To facilitate public participation, we are inviting public comment on the issues to be considered by the Council as listed in the ''Agenda'' section below. Written comments for distribution to Council members must be submitted no later than November 2, 2015, if Council review is desired prior to the meeting. Written comments may be submitted using the Federal eRulemaking Portal at *http://www.regulations.gov.* If your material cannot be submitted using *http://www.regulations.gov,* contact the person in the **FOR FURTHER INFORMATION CONTACT** section of this document for alternate instructions.

Instructions: All submissions received must include the words ''Department of Homeland Security'' and the docket number of this action, USCG–2010–0164. Comments received will be posted without alteration at *http://www.regulations.gov,* including any personal information provided. You may review a Privacy Act notice regarding the Federal Docket Management System in the March 24, 2005, issue of the **Federal Register** (70 FR 15086).

Docket: For access to the docket to read documents or comments related to this notice, go to *http://www.regulations.gov* insert USCG–2010–0164 in the ''Search'' box, press Enter, then click the item you wish to view.

FOR FURTHER INFORMATION CONTACT: Mr. Jeff Ludwig, Alternate Designated Federal Officer for the National Boating Safety Advisory Council, telephone (202) 372–1061, or at *jeffrey.a.ludwig@uscg.mil.*

SUPPLEMENTARY INFORMATION: Notice of this meeting is given under the *Federal Advisory Committee Act,* (Title 5, U.S.C., Appendix). Congress established the National Boating Safety Advisory Council in the *Federal Boat Safety Act of 1971* (Pub. L. 92–75). The National Boating Safety Advisory Council currently operates under the authority of 46 U.S.C. 13110, which requires the Secretary of Homeland Security and the Commandant of the Coast Guard by delegation to consult with the National Boating Safety Advisory Council in prescribing regulations for recreational vessels and associated equipment and on other major safety matters. See 46 U.S.C. 4302(c) and 13110(c).

Meeting Agenda

The agenda for the National Boating Safety Advisory Council meeting is as follows:

Thursday, November 12, 2015

(1) Opening remarks and presentation of awards to outgoing members.

(2) Receipt and discussion of the following reports:

(a) Chief, Office of Auxiliary and Boating Safety, Update on the Coast Guard's implementation of National Boating Safety Advisory Council Resolutions and Recreational Boating Safety Program report.

(b) Alternate Designated Federal Officer's report concerning Council administrative and logistical matters.

(c) Coast Guard Adoption of Electronic Aids to Navigation.

(d) Nonprofit Organization Grant Update.

(e) Progress Report on the Next National Recreational Boating Survey.

(3) Subcommittee Session: Boats and Associated Equipment Subcommittee *Issues to be discussed include alternatives to pyrotechnic visual distress signals; grant projects related to boats and associated equipment; and updates to 33 CFR 181 ''Manufacturer Requirements'' and 33 CFR 183 ''Boats and Associated Equipment.''*

(4) Prevention Through People Subcommittee. *Issues to be discussed include life jacket carriage requirements for certain recreational vessels and licensing requirements for on-water boating safety instruction providers.*

(5) Public comment period.

(6) Adjournment of Meeting.

Friday, November 13, 2015

The morning session will be dedicated to Subcommittee sessions:

(1) Recreational Boating Safety Strategic Planning Subcommittee. *Issues to be discussed include progress on implementation of the 2012–2016 Strategic Plan, and development of the 2017–2021 Strategic Plan.*

The full Council will resume meeting in the afternoon on November 13, 2015.

(1) Receipt and Discussion of the Boats and Associated Equipment, Prevention through People and The Recreational Boating Safety Strategic Planning Subcommittee reports.

(2) Discussion of any recommendations to be made to the Coast Guard.

(3) Public comment period.

(4) Voting on any recommendations to be made to the Coast Guard.

(5) Adjournment of meeting.

There will be a comment period for the National Boating Safety Advisory Council members and a comment period for the public after each report presentation, but before each is voted on by the Council. The Council members will review the information presented on each issue, deliberate on any recommendations presented in the Subcommittees' reports, and formulate recommendations for the Department's consideration.

The meeting agenda and all meeting documentation can be found at: *http://homeport.uscg.mil/NBSAC.* Alternatively, you may contact Mr. Jeff Ludwig as noted in the **FOR FURTHER INFORMATION CONTACT** section above.

Public oral comment periods will be held during the meetings after each presentation and at the end of each day. Speakers are requested to limit their comments to 3 minutes. Please note that the public comment periods may end before the time indicated, following the last call for comments. Contact Mr. Jeff Ludwig as indicated above to register as a speaker.

Dated: October 20, 2015.

Verne B. Gifford, Jr.

Captain, U.S. Coast Guard, Director of Inspections and Compliance.

[FR Doc. 2015–27056 Filed 10–22–15; 8:45 am]

BILLING CODE 9110–04–P

DEPARTMENT OF HOMELAND SECURITY

Coast Guard

[Docket No. USCG–2015–0911

Information Collection Request to Office of Management and Budget; OMB Control Number: 1625–0112

AGENCY: Coast Guard, DHS.

ACTION: Sixty-day notice requesting comments.

SUMMARY: In compliance with the Paperwork Reduction Act of 1995, the U.S. Coast Guard intends to submit an Information Collection Request (ICR) to the Office of Management and Budget (OMB), Office of Information and Regulatory Affairs (OIRA), requesting approval for reinstatement, with change, of the following collection of information: 1625–0112, Enhanced Maritime Domain Awareness via Electronic Transmission of Vessel Transit Data. Our ICR describe the information we seek to collect from the public. Before submitting this ICR to OIRA, the Coast Guard is inviting comments as described below.

DATES: Comments must reach the Coast Guard on or before December 22, 2015.

ADDRESSES: You may submit comments identified by Coast Guard docket number [USCG–2015–0911] to the Coast Guard using the Federal eRulemaking Portal at *http://www.regulations.gov*. See the ''Public participation and request for comments'' portion of the **SUPPLEMENTARY INFORMATION** section for further instructions on submitting comments.

A copy of the ICR is available through the docket on the Internet at *http://www.regulations.gov*. Additionally, copies are available from: COMMANDANT (CG–612), ATTN: PAPERWORK REDUCTION ACT MANAGER, U.S. COAST GUARD, 2703 MARTIN LUTHER KING JR. AVE. SE., STOP 7710, WASHINGTON, DC 20593–7710.

FOR FURTHER INFORMATION CONTACT: Mr. Anthony Smith, Office of Information Management, telephone 202–475–3532, or fax 202–273–8405, for questions on these documents.

SUPPLEMENTARY INFORMATION:

Public Participation and Request for Comments

This Notice relies on the authority of the Paperwork Reduction Act of 1995; 44 U.S.C. Chapter 35, as amended. An ICR is an application to OIRA seeking the approval, extension, or renewal of a Coast Guard collection of information (Collection). The ICR contains information describing the Collection's purpose, the Collection's likely burden on the affected public, an explanation of the necessity of the Collection, and other important information describing the Collection. There is one ICR for each Collection.

The Coast Guard invites comments on whether this ICR should be granted based on the Collection being necessary for the proper performance of Departmental functions. In particular, the Coast Guard would appreciate comments addressing: (1) The practical utility of the Collection; (2) the accuracy of the estimated burden of the Collection; (3) ways to enhance the quality, utility, and clarity of information subject to the Collection; and (4) ways to minimize the burden of the Collection on respondents, including the use of automated collection techniques or other forms of information technology. In response to your comments, we may revise this ICR or decide not to seek reinstatement of the Collection. We will consider all comments and material received during the comment period.

We encourage you to respond to this request by submitting comments and related materials. Comments must contain the OMB Control Number of the ICR and the docket number of this request, [USCG–2015–0911], and must be received by December 22, 2015.

Submitting Comments

We encourage you to submit comments through the Federal eRulemaking Portal at *http://www.regulations.gov*. If your material cannot be submitted using *http://www.regulations.gov,* contact the person in the **FOR FURTHER INFORMATION CONTACT** section of this document for alternate instructions. Documents mentioned in this notice, and all public comments, are in our online docket at *http://www.regulations.gov* and can be viewed by following that Web site's instructions. Additionally, if you go to the online docket and sign up for email alerts, you will be notified when comments are posted.

We accept anonymous comments. All comments received will be posted without change to *http://www.regulations.gov* and will include any personal information you have provided. For more about privacy and the docket, you may review a Privacy Act notice regarding the Federal Docket Management System in the March 24, 2005, issue of the **Federal Register** (70 FR 15086).

Information Collection Request

1. *Title:* Enhanced Maritime Domain Awareness via Electronic Transmission of Vessel Transit Data.

OMB Control Number: 1625–0112.

Summary: The Coast Guard collects, stores, and analyzes data transmitted by Long Range Identification and Tracking (LRIT) and Automatic Identification System (AIS) to enhance maritime domain awareness (MDA). Awareness and threat knowledge are critical for securing the maritime domain and the key to preventing adverse events. Data is also used for marine safety and environmental protection purposes.

Need: To ensure port safety and security and to ensure the uninterrupted flow of commerce.

Forms: None.

Respondents: Owners or operators of certain vessels.

Frequency: On occasion.

Hour Burden Estimate: The estimated burden has increased from 204 hours to 47,245 hours a year due to an increase in the estimated annual number of responses. The increase in responses is due to the inclusion of AIS into this ICR.

Authority: The Paperwork Reduction Act of 1995; 44 U.S.C. Chapter 35, as amended.

Dated: October 18, 2015.

Thomas P. Michelli,

U.S. Coast Guard, Deputy Chief Information Officer.

[FR Doc. 2015–27038 Filed 10–22–15; 8:45 am]

BILLING CODE 9110–04–P

DEPARTMENT OF HOUSING AND URBAN DEVELOPMENT

[Docket No. FR–5831–N–50]

30-Day Notice of Proposed Information Collection: Continuum of Care Homeless Assistance Grant Application

AGENCY: Office of the Chief Information Officer, HUD.

ACTION: Notice.

SUMMARY: HUD has submitted the proposed information collection requirement described below to the Office of Management and Budget (OMB) for review, in accordance with the Paperwork Reduction Act. The purpose of this notice is to allow for an additional 30 days of public comment.

DATES: *Comments Due Date:* November 23, 2015.

ADDRESSES: Interested persons are invited to submit comments regarding this proposal. Comments should refer to the proposal by name and/or OMB

Control Number and should be sent to: HUD Desk Officer, Office of Management and Budget, New Executive Office Building, Washington, DC 20503; fax: 202–395–5806. Email: *OIRA_Submission@omb.eop.gov*

FOR FURTHER INFORMATION CONTACT: Colette Pollard, Reports Management Officer, QMAC, Department of Housing and Urban Development, 451 7th Street SW., Washington, DC 20410; email Colette Pollard at *Colette.Pollard@hud.gov* or telephone 202–402–3400. 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.

Copies of available documents submitted to OMB may be obtained from Ms. Pollard.

SUPPLEMENTARY INFORMATION: This notice informs the public that HUD is seeking approval from OMB for the information collection described in Section A.

The **Federal Register** notice that solicited public comment on the information collection for a period of 60 days was published on August 11, 2015.

A. Overview of Information Collection

Title of Information Collection: Continuum of Care Homeless Assistance Grant Application.

OMB Approval Number: 2506–0112.

Type of Request: Revision of a currently approved collection.

Form Number: CoC Consolidated Application (all parts), SF 424, HUD SF 424 SUPP, HUD–2991, HUD–92041, HUD–27300, HUD–2880, SF–LLL, HUD–40090–4, HUD–50070.

Description of the need for the information and proposed use: The regulatory authority to collect this information is contained in 24 CFR part 578, and is authorized by the McKinney-Vento Act, as amended by S. 896 The Homeless Emergency Assistance and Rapid Transition to Housing (HEARTH) Act of 2009 (42 U.S.C. 11371 *et seq.*) which states that ''The Secretary shall award grants, on a competitive basis, and using the selection criteria described in section 427, to carry out eligible activities under this subtitle for projects that meet the program requirements under section 426, either by directly awarding funds to project sponsors or by awarding funds to unified funding agencies.''(SEC.422(a))

The CoC Homeless Assistance Grant Application (OMB 2506–0112) is the second phase of the information collection process to be used in HUD's CoC Program Competition authorized by the HEARTH Act. During this phase, HUD collects information from the state and local Continuum of Cares (CoCs) through the CoC Consolidated Application which is comprised of the CoC Application, and the Priority Listing which includes the individual project recipients' project applications.

The CoC Consolidated Grant Application is necessary for the selection of proposals submitted to HUD (by State and local governments, public housing authorities, and nonprofit organization) for the grant funds available through the Continuum of Care Program, in order to make decisions for the awarding CoC Program funds.

Respondents (*i.e.* affected public): States, local governments, private nonprofit organizations, public housing authorities, and community mental health associations that are public nonprofit organizations.

Estimated Number of Respondents: 4,577 applicants.

Estimated Number of Responses: 8,869 applications.

Frequency of Response: 1 response per year.

Average Hours per Response: 22.75 hours.

Total Estimated Burdens: 201,779.87 hours.

B. Solicitation of Public Comment

This notice is soliciting comments from members of the public and affected parties concerning the collection of information described in Section A on the following:

(1) 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) The accuracy of the agency's estimate of the burden of the proposed collection of information;

(3) Ways to enhance the quality, utility, and clarity of the information to be collected; and

(4) Ways to 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.

HUD encourages interested parties to submit comment in response to these questions.

Authority: 12 U.S.C. 1701z–1 Research and Demonstrations.

Dated: October 16, 2015.

Colette Pollard,

Department Reports Management Officer, Office of the Chief Information Officer.

[FR Doc. 2015–27023 Filed 10–22–15; 8:45 am]

BILLING CODE 4210–67–P

DEPARTMENT OF HOUSING AND URBAN DEVELOPMENT

[Docket No. FR–5831–N–51]

30-Day Notice of Proposed Information Collection: Loan Guarantee Recovery Fund Established Pursuant to the Church Arson Prevention Act of 1996

AGENCY: Office of the Chief Information Officer, HUD.

ACTION: Notice.

SUMMARY: HUD has submitted the proposed information collection requirement described below to the Office of Management and Budget (OMB) for review, in accordance with the Paperwork Reduction Act. The purpose of this notice is to allow for an additional 30 days of public comment.

DATES: *Comments Due Date:* November 23, 2015.

ADDRESSES: Interested persons are invited to submit comments regarding this proposal. Comments should refer to the proposal by name and/or OMB Control Number and should be sent to: HUD Desk Officer, Office of Management and Budget, New Executive Office Building, Washington, DC 20503; fax: 202–395–5806. Email: *OIRA_Submission@omb.eop.gov.*

FOR FURTHER INFORMATION CONTACT: Colette Pollard, Reports Management Officer, QMAC, Department of Housing and Urban Development, 451 7th Street SW., Washington, DC 20410; email Colette Pollard at *Colette.Pollard@hud.gov* or telephone 202–402–3400. 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.

Copies of available documents submitted to OMB may be obtained from Ms. Pollard.

SUPPLEMENTARY INFORMATION: This notice informs the public that HUD is seeking approval from OMB for the information collection described in Section A.

The **Federal Register** notice that solicited public comment on the information collection for a period of 60 days was published on August 19, 2015.

A. Overview of Information Collection

Title of Information Collection: Loan Guarantee Recovery Fund established pursuant to the Church Arson Prevention Act of 1996.

OMB Approval Number: 2506–0159.

Type of Request: Extension of currently approved collection.

Form Number: HUD–40076–LGA, SF–424.

Description of the need for the information and proposed use: The purpose of this submission is for the application of the Section 4 Loan Guarantee Recovery Fund loan guarantee process. Under this program, HUD provides loan guarantees to lending institutions that provide loans to houses of worship that have been the victims of hate crime or arson. Under the Loan Guarantee Agreement, the lending institution is required to provide repayment information to HUD on a monthly basis to ensure the lender is repaying the loan within the guidelines of the Loan Guarantee Agreement.

Respondents (*i.e.* affected public): 36.

Estimated Number of Respondents: 36.

Estimated Number of Responses: 432.

Frequency of Response: 24.

Average Hours per Response: 2.

Total Estimated Burdens: 864.

B. Solicitation of Public Comment

This notice is soliciting comments from members of the public and affected parties concerning the collection of information described in Section A on the following:

(1) 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) The accuracy of the agency's estimate of the burden of the proposed collection of information;

(3) Ways to enhance the quality, utility, and clarity of the information to be collected; and

(4) Ways to 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.

HUD encourages interested parties to submit comment in response to these questions.

Authority: 12 U.S.C. 1701z–1 Research and Demonstrations.

Dated: October 16, 2015.

Colette Pollard,

Department Reports Management Officer, Office of the Chief Information Officer.

[FR Doc. 2015–27022 Filed 10–22–15; 8:45 am]

BILLING CODE 4210–67–P

DEPARTMENT OF HOUSING AND URBAN DEVELOPMENT

[Docket No. FR–5828–N–43]

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: ARMY: Ms. Veronica Rines, Office of the Assistant Chief of Staff for Installation Management, Department of Army, Room 5A128, 600 Army Pentagon, Washington, DC 20310, (571) 256–8145; COAST GUARD: Commandant, United States Coast Guard, Attn: Aretha Swann, 2703 Martin Luther King Jr. Avenue SE, Stop 7741, Washington, DC 20593–7714; (202) 475–5628; GSA: Mr. Flavio Peres, General Services Administration, Office of Real Property Utilization and Disposal, 1800 F Street NW., Room 7040 Washington, DC 20405, (202) 501–0084; 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: October 15, 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 10/23/2015

Suitable/Available Properties

Building

Louisiana

110 Willow Street
110 Willow Street
Homer LA 71040
Landholding Agency: GSA
Property Number: 54201540005
Status: Excess
GSA Number: 7–A–LA–0533–AA
Directions: Disposal Agency: GSA; Landholding Agency: Interior
Comments: 54+ yrs. old; 1,754 sq. ft.; residential; vacant 12+ mos.; sits on 0.37 acres land; contact GSA for more information.

Minnesota

FM Repeater Station Install #3
Sec. 24, T. 105N, R 5W
Dresbach MN
Landholding Agency: GSA
Property Number: 54201540004
Status: Excess
GSA Number: 1–D–MN–598
Directions: Land Holding Agency: COE; Disposal Agency: GSA
Comments: 50+ yrs. old; 80 sq. ft.; storage; average condition; contact GSA for more information.

Texas

3 Bldgs.; Former Hebbronvil
1312 W. Harald Street
Hebbronville TX 78361
Landholding Agency: GSA
Property Number: 54201540001
Status: Surplus
GSA Number: 7–X–TX–0621–AB
Directions: Block Office Bldg.; Storage Bldg. & Wooden Storage Bldg.
Comments: 25–65 yrs. old; 5,834 gross sq. ft.; office; water damage on ceiling of office bldg.; contact GSA for more information.

Wisconsin

FM Repeater Station Install.#3
Sec. 36, T. 25N, R 13W
Bay City WI
Landholding Agency: GSA
Property Number: 54201540002
Status: Excess
GSA Number: 1–D–WI–621
Directions: Land Holding Agency: COE; Disposal Agency: GSA
Comments: 50+ yrs. old; 80 sq. ft.; storage; average condition; contact GSA for more information.

FM Repeater Station Install #3
Sec. 26, T. 9N, R 6W
Lynxville WI 54626
Landholding Agency: GSA
Property Number: 54201540003
Status: Excess
GSA Number: 1–D–WI–622
Directions: Land Holding Agency: COE; Disposal Agency: GSA
Comments: 50+ yrs. old; 80 sq. ft.; storage; average condition; contact GSA for more information.

Unsuitable Properties

Building

Connecticut

Building 548, Naval Submarine
Lower Base off Argonaut & Cisco Ave.
Groton CT 06349
Landholding Agency: Navy
Property Number: 77201540001
Status: Excess
Comments: Flam/explosive located on adjacent indust, comm., or Fed. fac.; heavy weaponry is actively loaded on board submarines; public access denied and no alter method to gain access w/o compromising national security.
Reasons: Within 2000 ft. of flammable or explosive material; Secured Area

Indiana

2 Buildings
2828 Madison S. Ave.
Anderson IN 46016
Landholding Agency: Army
Property Number: 21201540001
Status: Unutilized
Directions: AR009 & AR033
Comments: Public access denied and no alternative method to gain access without compromising national security.
Reasons: Secured Area

North Carolina

Swimming Pool Bldg. (33)(24035)
1664 Weeksville Road
Elizabeth City NC 27909
Landholding Agency: Coast Guard
Property Number: 88201540002
Status: Excess
Comments: property within military airfield; public access denied and no alternative method to gain access without compromising national security.
Reasons: Secured Area; Within airport runway clear zone

Land

Mississippi

Joe William Field North Solar
Joe Williams (OLF Bravo)
Naval Air Station Merd MS
Landholding Agency: Navy
Property Number: 77201540002
Status: Underutilized
Comments: public access denied and no alternative method to gain access without compromising national security.
Reasons: Secured Area

[FR Doc. 2015–26750 Filed 10–22–15; 8:45 am]

BILLING CODE 4210–67–P

DEPARTMENT OF THE INTERIOR

Fish and Wildlife Service

[Docket No. FWS–HQ–IA–2015–0153; FXIA16710900000–156–FF09A30000]

Endangered Species; Marine Mammals; Issuance of Permits

AGENCY: Fish and Wildlife Service, Interior.

ACTION: Notice of issuance of permits.

SUMMARY: We, the U.S. Fish and Wildlife Service (Service), have issued the following permits to conduct certain activities with endangered species, marine mammals, or both. We issue these permits under the Endangered Species Act (ESA) and Marine Mammal Protection Act (MMPA).

ADDRESSES: Brenda Tapia, U.S. Fish and Wildlife Service, Division of Management Authority, Branch of Permits, MS: IA, 5275 Leesburg Pike, Falls Church, VA 22041; fax (703) 358–2281; or email *DMAFR@fws.gov.*

FOR FURTHER INFORMATION CONTACT: Brenda Tapia, (703) 358–2104 (telephone); (703) 358–2281 (fax); *DMAFR@fws.gov* (email).

SUPPLEMENTARY INFORMATION: On the dates below, as authorized by the provisions of the ESA (16 U.S.C. 1531 *et seq.*), as amended, and/or the MMPA, as amended (16 U.S.C. 1361 *et seq.*), we issued requested permits subject to certain conditions set forth therein. For each permit for an endangered species, we found that (1) The application was filed in good faith, (2) The granted permit would not operate to the disadvantage of the endangered species, and (3) The granted permit would be consistent with the purposes and policy set forth in section 2 of the ESA.

Permit No.	Applicant	Receipt of application **Federal Register** notice	Permit issuance date
	Endangered Species		
46280B	Project Survival	80 FR 24961; May 1, 2015	September 23, 2015.
63546B	Project Survival	80 FR 24961; May 1, 2015	September 23, 2015.
075249	Sam Noble Oklahoma Museum of Natural History	80 FR 43790; July 23, 2015	September 23, 2015.
64797A	Recordbuck Ranch	80 FR 43790; July 23, 2015	September 23, 2015.
51130B	Brady Champion Ranch, LLC	80 FR 43790; July 23, 2015	September 25, 2015.
58205B	Washington Park Zoo	80 FR 43790; July 23, 2015	September 10, 2015.
71117B	Mark Corry	80 FR 46042; August 3, 2015	September 10, 2015.
59071B	Earth Promise	80 FR 46042; August 3, 2015	September 23, 2015.
71735B	Steven Smith	80 FR 47947; August 10, 2015	September 11, 2015.
72213B	John Klein	80 FR 47947; August 10, 2015	September 11, 2015.
66259B	Stanford University	80 FR 47947; August 10, 2015	September 29, 2015.
72286B	Robert Windstead	80 FR 51299; August 24, 2015	September 25, 2015.
72842B	Jeffery Palmer	80 FR 51299; August 24, 2015	September 25, 2015.
73008B	Andrew Wood	80 FR 51299; August 24, 2015	September 25, 2015.
66618B	U.S. Geological Survey	80 FR 51299; August 24, 2015	October 9, 2015.
68941B	John Justus	80 FR 51299; August 24, 2015	September 25, 2015.
53920B	Zoological Society of Cincinnati/Cincinnati Zoo & Botanical Gardens.	80 FR 53323; September 3, 2015	October 9, 2015.
74210B	Richard Papapietro	80 FR 55868; September 17, 2015	October 19, 2015.
74205B	David Florance	80 FR 55868; September 17, 2015	October 19, 2015.
	Marine Mammals		
45505B	Terri Williams, University of California	79 FR 72007; December 4, 2014	October 13, 2015.

Availability of Documents

Documents and other information submitted with these applications are available for review, subject to the requirements of the Privacy Act and Freedom of Information Act, by any party who submits a written request for a copy of such documents to: U.S. Fish and Wildlife Service, Division of Management Authority, Branch of Permits, MS: IA, 5275 Leesburg Pike, Falls Church, VA 22041; fax (703) 358–2281.

Brenda Tapia,

Program Analyst/Data Administrator, Branch of Permits, Division of Management Authority.

[FR Doc. 2015–26878 Filed 10–22–15; 8:45 am]

BILLING CODE 4333–15–P

DEPARTMENT OF THE INTERIOR

Fish and Wildlife Service

[Docket No. FWS–HQ–IA–2015–0154; FXIA16710900000–156–FF09A30000]

Endangered Species; Receipt of Applications for Permit

AGENCY: Fish and Wildlife Service, Interior.

ACTION: Notice of receipt of applications for permit.

SUMMARY: We, the U.S. Fish and Wildlife Service, invite the public to comment on the following applications to conduct certain activities with endangered species. With some exceptions, the Endangered Species Act (ESA) prohibits activities with listed species unless Federal authorization is acquired that allows such activities.

DATES: We must receive comments or requests for documents on or before November 23, 2015.

ADDRESSES: *Submitting Comments:* You may submit comments by one of the following methods:

- *Federal eRulemaking Portal: http://www.regulations.gov.* Follow the instructions for submitting comments on Docket No. FWS–HQ–IA–2015–0154.
- *U.S. mail or hand-delivery:* Public Comments Processing, Attn: Docket No. FWS–HQ–IA–2015–0154; U.S. Fish and Wildlife Service Headquarters, MS: BPHC; 5275 Leesburg Pike, Falls Church, VA 22041–3803.

We will post all comments on *http://www.regulations.gov.* This generally means that we will post any personal information you provide us (see the Public Comments section below for more information). *Viewing Comments:* Comments and materials we receive will be available for public inspection on *http://www.regulations.gov,* or by appointment, between 8 a.m. and 4 p.m., Monday through Friday, except Federal holidays, at the U.S. Fish and Wildlife Service, Division of Management Authority, 5275 Leesburg Pike, Falls Church, VA 22041–3803; telephone 703–358–2095.

FOR FURTHER INFORMATION CONTACT: Brenda Tapia, (703) 358–2104 (telephone); (703) 358–2281 (fax); *DMAFR@fws.gov* (email).

SUPPLEMENTARY INFORMATION:

I. Public Comment Procedures

A. How do I request copies of applications or comment on submitted applications?

Send your request for copies of applications or comments and materials concerning any of the applications to the contact listed under **ADDRESSES**. Please include the **Federal Register** notice publication date, the PRT-number, and the name of the applicant in your request or submission. We will not consider requests or comments sent to an email or address not listed under **ADDRESSES**. If you provide an email address in your request for copies of applications, we will attempt to respond to your request electronically.

Please make your requests or comments as specific as possible. Please confine your comments to issues for which we seek comments in this notice, and explain the basis for your comments. Include sufficient information with your comments to allow us to authenticate any scientific or commercial data you include.

The comments and recommendations that will be most useful and likely to influence agency decisions are: (1) Those supported by quantitative information or studies; and (2) Those that include citations to, and analyses of, the applicable laws and regulations. We will not consider or include in our administrative record comments we receive after the close of the comment period (see **DATES**) or comments delivered to an address other than those listed above (see **ADDRESSES**).

B. May I review comments submitted by others?

Comments, including names and street addresses of respondents, will be available for public review at the street address listed under **ADDRESSES**. The public may review documents and other information applicants have sent in support of the application unless our allowing viewing would violate the Privacy Act or Freedom of Information Act. 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.

II. Background

To help us carry out our conservation responsibilities for affected species, and in consideration of section 10(a)(1)(A) of the Endangered Species Act of 1973, as amended (16 U.S.C. 1531 *et seq.*), along with Executive Order 13576, ''Delivering an Efficient, Effective, and Accountable Government,'' and the President's Memorandum for the Heads of Executive Departments and Agencies of January 21, 2009—Transparency and Open Government (74 FR 4685; January 26, 2009), which call on all Federal agencies to promote openness and transparency in Government by disclosing information to the public, we invite public comment on these permit applications before final action is taken.

III. Permit Applications

Endangered Species

Applicant: Megan Cattau, New York, NY; PRT–61197B

The applicant requests a permit to import hair samples from wild orangutans (*Pongo pygmaeus*) from Indonesia for scientific research purposes.

Applicant: Tanganyika Wildlife Park, Goddard, KS; PRT–57032B

The applicant requests a permit to import one male and three female captive-bred cheetahs (*Acinonyx jubatus*) from De Wildt Cheetah Breeding Centre, De Wildt, South Africa, for the purpose of enhancement of the survival of the species.

Applicant: Christopher Shaw, Rolla, MO; PRT–78418b

The applicant requests a permit to import a sport-hunted trophy of one male bontebok (*Damaliscus pygargus pygargus*) culled from a captive herd maintained under the management program of the Republic of South Africa, for the purpose of enhancement of the survival of the species.

Brenda Tapia,

Program Analyst/Data Administrator, Branch of Permits, Division of Management Authority.

[FR Doc. 2015–26877 Filed 10–22–15; 8:45 am]

BILLING CODE 4333–15–P

DEPARTMENT OF THE INTERIOR

Bureau of Indian Affairs

[156A2100DD/AAKC001030/ A0A501010.999900 253G]

Indian Gaming

AGENCY: Bureau of Indian Affairs, Interior.

ACTION: Notice of extension of Tribal-State Class III Gaming Compact.

SUMMARY: This publishes notice of the extension of the Class III gaming compact between the Pyramid Lake Paiute Tribe and the State of Nevada.

DATES: *Effective Date:* October 23, 2015.

FOR FURTHER INFORMATION CONTACT: Ms. Paula L. Hart, Director, Office of Indian Gaming, Office of the Deputy Assistant Secretary—Policy and Economic Development, Washington, DC 20240, (202) 219–4066.

SUPPLEMENTARY INFORMATION: Pursuant to 25 CFR 293.5, an extension to an existing tribal-state Class III gaming compact does not require approval by the Secretary if the extension does not include any amendment to the terms of the compact. The Pyramid Lake Paiute Tribe and the State of Nevada have reached an agreement to extend the expiration of their existing Tribal-State Class III gaming compact to February 23, 2017. This publishes notice of the new expiration date of the compact.

Dated: October 16, 2015.

Kevin K. Washburn,

Assistant Secretary—Indian Affairs.

[FR Doc. 2015–27080 Filed 10–22–15; 8:45 am]

BILLING CODE 4337–15–P

DEPARTMENT OF THE INTERIOR

Bureau of Indian Affairs

[156A2100DD/AAKC001030/ A0A501010.999900 253G]

Indian Gaming

AGENCY: Bureau of Indian Affairs, Interior.

ACTION: Notice of Tribal-State Class III Gaming Compacts taking effect.

SUMMARY: The Bureau of Indian Affairs provides notice that the Tribal State Compact between the State of California and the Jackson Band of Miwuk Indians governing Class III gaming (Compact) is effective on publication of this notice.

DATES: *Effective Date:* October 23, 2015.

FOR FURTHER INFORMATION CONTACT: Ms. Paula L. Hart, Director, Office of Indian Gaming, Office of the Deputy Assistant Secretary—Policy and Economic Development, Washington, DC 20240, (202) 219–4066.

SUPPLEMENTARY INFORMATION: Under section 11 of the Indian Gaming Regulatory Act (IGRA) Public Law 100–497, 25 U.S.C. 2701 *et seq.,* the Secretary of the Interior shall publish in the **Federal Register** notice of approved Tribal-State compacts for the purpose of engaging in Class III gaming activities on Indian lands. As required by 25 CFR 293.4, all compacts are subject to review and approval by the Secretary. The Secretary took no action on the Compact within 45 days of its submission. Therefore, the Compact is considered to have been approved, but only to the extent the Compact is consistent with IGRA. *See* 25 U.S.C. 2710(d)(8)(C).

Dated: October 16, 2015.

Kevin K. Washburn,

Assistant Secretary—Indian Affairs.

[FR Doc. 2015–27090 Filed 10–22–15; 8:45 am]

BILLING CODE 4337–15–P

DEPARTMENT OF THE INTERIOR

Bureau of Indian Affairs

[156A2100DD/AAKC001030/ A0A501010.999900 253G]

Indian Gaming

AGENCY: Bureau of Indian Affairs, Interior.

ACTION: Notice of Tribal-State Class III Gaming Compact taking effect.

SUMMARY: Notice is hereby given that the Indian Gaming Compact between the State of New Mexico and the Pueblo of Laguna governing Class III gaming (Compact) is taking effect.

DATES: *Effective date:* October 23, 2015.

FOR FURTHER INFORMATION CONTACT: Ms. Paula L. Hart, Director, Office of Indian Gaming, Office of the Assistant Secretary—Indian Affairs, Washington, DC 20240, (202) 219–4066.

SUPPLEMENTARY INFORMATION: Under section 11 of the Indian Gaming Regulatory Act (IGRA) Public Law 100–497, 25 U.S.C. 2701 *et seq.,* the Secretary of the Interior shall publish in the **Federal Register** notice of approved Tribal-State compacts for the purpose of engaging in Class III gaming activities on Indian lands. As required by 25 CFR 293.4, all compacts are subject to review and approval by the Secretary. The Secretary took no action on the Compact within 45 days of its submission. Therefore, the Compact is considered to have been approved, but only to the extent the Compact is consistent with IGRA. *See* 25 U.S.C. 2710(d)(8)(C).

Dated: October 16, 2015.

Kevin K. Washburn,

Assistant Secretary—Indian Affairs.

[FR Doc. 2015–27088 Filed 10–22–15; 8:45 am]

BILLING CODE 4337–15–P

DEPARTMENT OF THE INTERIOR

Bureau of Indian Affairs

[156A2100DD/AAKC001030/ A0A501010.999900 253G]

Indian Gaming

AGENCY: Bureau of Indian Affairs, Interior.

ACTION: Notice of Tribal-State Class III Gaming Compact taking effect.

SUMMARY: Notice is hereby given that the Indian Gaming Compact between the State of New Mexico and the Pueblo of Tesuque governing Class III gaming (Compact) taking effect.

DATES: *Effective date:* October 23, 2015.

FOR FURTHER INFORMATION CONTACT: Ms. Paula L. Hart, Director, Office of Indian Gaming, Office of the Assistant Secretary—Indian Affairs, Washington, DC 20240, (202) 219–4066.

SUPPLEMENTARY INFORMATION: Under section 11 of the Indian Gaming Regulatory Act (IGRA) Public Law 100–497, 25 U.S.C. 2701 *et seq.,* the Secretary of the Interior shall publish in the **Federal Register** notice of approved Tribal-State compacts for the purpose of engaging in Class III gaming activities on Indian lands. As required by 25 CFR 293.4, all compacts are subject to review and approval by the Secretary. The Secretary took no action on the Compact within 45 days of its submission. Therefore, the Compact is considered to have been approved, but only to the extent the Compact is consistent with IGRA. *See* 25 U.S.C. 2710(d)(8)(C).

Dated: October 16, 2015.

Kevin K. Washburn,

Assistant Secretary—Indian Affairs.

[FR Doc. 2015–27082 Filed 10–22–15; 8:45 am]

BILLING CODE 4337–15–P

DEPARTMENT OF THE INTERIOR

Bureau of Indian Affairs

[156A2100DD/AAKC001030/ A0A501010.999900 253G]

Indian Gaming

AGENCY: Bureau of Indian Affairs, Interior.

ACTION: Notice of Tribal-State Class III Gaming Compacts taking effect.

SUMMARY: Notice is hereby given that the Indian Gaming Compact between the State of New Mexico and the Pueblo of Santa Clara governing Class III gaming (Compact) is taking effect.

DATES: *Effective date:* October 23, 2015.

FOR FURTHER INFORMATION CONTACT: Ms. Paula L. Hart, Director, Office of Indian Gaming, Office of the Assistant Secretary—Indian Affairs, Washington, DC 20240, (202) 219–4066.

SUPPLEMENTARY INFORMATION: Under section 11 of the Indian Gaming Regulatory Act (IGRA) Public Law 100–497, 25 U.S.C. 2701 *et seq.,* the Secretary of the Interior shall publish in the **Federal Register** notice of approved Tribal-State compacts for the purpose of engaging in Class III gaming activities on Indian lands. As required by 25 CFR 293.4, all compacts are subject to review and approval by the Secretary. The Secretary took no action on the Compact within 45 days of its submission. Therefore, the Compact is considered to have been approved, but only to the extent the Compact is consistent with IGRA. *See* 25 U.S.C. 2710(d)(8)(C).

Dated: October 16, 2015.

Kevin K. Washburn,

Assistant Secretary—Indian Affairs.

[FR Doc. 2015–27091 Filed 10–22–15; 8:45 am]

BILLING CODE 4337–15–P

DEPARTMENT OF THE INTERIOR

Office of the Secretary

[ONRR–2012–0003 DS63602000 DR2000000.PX8000 167D0102R2]

U.S. Extractive Industries Transparency Initiative Advisory Committee Request for Nominees

AGENCY: Office of Natural Resources Revenue, Interior.

ACTION: Notice.

SUMMARY: The Department of the Interior (Interior) is seeking nominations for individuals to be Committee members or alternates on the U.S. Extractive Industries Transparency Initiative Advisory Committee (Committee). We seek nominees who can represent stakeholder constituencies from government, civil society, and industry so that we can fill current vacancies and create a roster of candidates in case future vacancies occur.

DATES: Submit nominations by December 31, 2015.

ADDRESSES: You may submit nominations by any of the following methods:

- Mail or hand-carry nominations to Ms. Rosita Compton Christian; Department of the Interior, 1849 C Street NW., MS 4211, Washington, DC 20240.
- Email nominations to *USEITI@ios.doi.gov*.

FOR FURTHER INFORMATION CONTACT: Rosita Compton Christian at (202) 208–0272 or (202) 513–0597; fax (202) 513–0682; email *Rosita.ComptonChristian@onrr.gov* or *USEITI@ios.doi.gov*; or via mail at the Department of the Interior; 1849 C Street NW., MS 4211; Washington, DC 20240.

SUPPLEMENTARY INFORMATION: Interior established the Committee on July 26, 2012, in accordance with the provisions of the Federal Advisory Committee Act (FACA), as amended (5 U.S.C. App.2), and with the concurrence of the General Services Administration. The Committee serves as the U.S. Extractive Industries Transparency Initiative Multi-Stakeholder Group and advises the Secretary of the Interior on design and implementation of the initiative.

The Committee does the following:

- Oversees the U.S. implementation of the Extractive Industries Transparency Initiative (EITI), a global standard for governments to publicly disclose revenues received from oil, gas, and mining assets belonging to the government, with parallel public disclosure by companies of payments to the

government (such as royalties, rents, bonuses, taxes, or other payments)
- Develops and recommends to the Secretary a fully-costed work plan, containing measurable targets and a timetable for implementation and incorporating an assessment of capacity constraints; this plan will be developed in consultation with key EITI stakeholders and published upon completion
- Provides opportunities for collaboration and consultation among stakeholders
- Advises the Secretary and posts for consideration by other stakeholders proposals for conducting long-term oversight and other activities necessary to achieve and maintain EITI-compliant status

The Committee consists of representatives from three stakeholder sectors. The sectors are as follows:
- Industry, including non-Federal representatives from the extractive industry-including oil, gas, and mining companies and industry-related trade associations
- Civil society, including organizations with an interest in extractive industries, transparency, and government oversight; members of the public; and public and/or private investors
- Government, including Federal, State, local, and Tribal governments and individual Indian mineral owners

In addition to honoring the EITI principle of self-selection within the stakeholder sector, we will consider the following criteria when making final selections:
- Understanding of and commitment to the EITI process
- Ability to collaborate and operate in a multi-stakeholder setting
- Access to and support from a relevant stakeholder constituency
- Basic understanding of the extractive industry and/or revenue collection or willingness to be educated on such matters

Nominations should include a resume providing relevant contact information and an adequate description of the nominee's qualifications, including information that would enable the Department of the Interior to make an informed decision regarding meeting the membership requirements for the Committee and to permit the Department of the Interior to contact a potential member.

Parties are strongly encouraged to work with and within stakeholder sectors (including industry, civil society, and government sectors, as the EITI process defines) to jointly consider and submit nominations that, overall, reflect the diversity and breadth of their sector. Nominees are strongly encouraged to include supporting letters from constituents, trade associations, alliances, and/or other organizations that indicate support by a meaningful constituency for the nominee.

Individuals who are Federally registered lobbyists are ineligible to serve on FACA and non-FACA boards, committees, or councils in an individual capacity. The term ''individual capacity'' refers to individuals who are appointed to exercise their own individual best judgment on behalf of the government, such as when they are designated Special Government Employees, rather than being appointed to represent a particular interest.

The Committee will meet quarterly or at the request of the Designated Federal Officer. Non-Federal members of the Committee will serve without compensation. However, we may pay the travel and per diem expenses of Committee members, if appropriate, under the Federal Travel Regulations.

To learn more about USEITI please visit the official Web site at *www.doi.gov/eiti.*

Dated: October 14, 2015.

Paul A. Mussenden,

Deputy Assistant Secretary—Natural Resources Revenue Management.

[FR Doc. 2015–27095 Filed 10–22–15; 8:45 am]

BILLING CODE 4335–30–P

DEPARTMENT OF THE INTERIOR

Bureau of Land Management

[LLORW00000.L10200000.ML0000. LXSSEWRA0000.16XL1109AF.HAG16–0027]

Notice of Public Meeting for the Eastern Washington Resource Advisory Council

AGENCY: Bureau of Land Management, Interior.

ACTION: Notice of public meeting.

SUMMARY: In accordance with the Federal Land Policy and Management Act and the Federal Advisory Committee Act of 1972, and the U.S. Department of the Interior, Bureau of Land Management (BLM), the Eastern Washington Resource Advisory Council (RAC) will meet as indicated below:

DATES: The Eastern Washington RAC will hold a public meeting Thursday, Nov. 5, 2015. The meeting will run from 9:00 a.m. to 4:30 p.m. The meeting will be held at the Holiday Inn in Yakima, Washington, and will include a field trip to the Yakima River Canyon. A public comment period will be available in the afternoon.

FOR FURTHER INFORMATION CONTACT: Jeff Clark, Public Affairs Specialist, BLM Spokane District Office, 1103 N. Fancher Rd., Spokane, Washington 99212, (509) 536–1297, or email *jeffclark@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 Eastern Washington RAC consists of 15 members chartered and appointed by the Secretary of the Interior. Their diverse perspectives are represented in commodity, conservation, and general interests. They provide advice to BLM resource managers regarding management plans and proposed resource actions on public land in central and eastern Washington.

Agenda items for the November 2015 meeting include a field tour of the Yakima River Canyon Recreation Area, an update on the Eastern Washington Resource Management Plan, a presentation of the business plan for a fee season extension for the Yakima River Canyon, committee and member updates, and any other matters that may reasonably come before the RAC. This meeting is open to the public in its entirety; however, transportation during the field tour portion of the meeting on Nov. 5 will not be provided to members of the public. Information to be distributed to the Eastern Washington RAC is requested prior to the start of each meeting. A public comment period will be available on Nov. 5, 2015, at 3:30 p.m. Unless otherwise approved by the Eastern Washington RAC Chair, the public comment period will last no longer than 30 minutes. Each speaker may address the RAC for a maximum of 5 minutes. Meeting times and the duration scheduled for public comment periods may be extended or altered when the authorized representative considers it necessary to accommodate business and all who seek to be heard regarding matters before the Eastern Washington RAC.

Dennis Strange,

Spokane District Manager.

[FR Doc. 2015–26978 Filed 10–22–15; 8:45 am]

BILLING CODE 4310–33–P

DEPARTMENT OF THE INTERIOR

Bureau of Land Management

[LLCON05000–L16100000–DU0000–16X]

Notice of Meeting, Northwest Resource Advisory Council's Travel Management Sub-Group

AGENCY: Bureau of Land Management, Interior.

ACTION: Notice of public meeting.

SUMMARY: In accordance with the Federal Land Policy and Management Act and the Federal Advisory Committee Act of 1972, the U.S. Department of the Interior, Bureau of Land Management (BLM) Northwest Resource Advisory Council (RAC) Travel Management Sub-Group will meet as indicated below.

DATES: The Northwest RAC Travel Management Sub-Group has scheduled a meeting November 16, 2015, from 1 to 3 p.m., with a public comment period regarding matters on the agenda at 2 p.m. A specific agenda for the meeting will be available prior to the meeting at *http://www.blm.gov/co/st/en/BLM_Resources/racs/nwrac.html.*

ADDRESSES: The meeting will be held at the BLM White River Field Office, 220 E. Market St., Meeker, CO 81641.

FOR FURTHER INFORMATION CONTACT: Heather Sauls, Planning and Environmental Coordinator, White River Field Office, see address above. Phone: (970) 878–3855. Email: *hsauls@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, seven 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 15-member Northwest RAC advises the Secretary of the Interior, through the BLM, on a variety of planning and management issues associated with public land management in northwest Colorado. The Northwest RAC has formed a 13-member Travel Management Sub-Group to assist with the BLM Colorado White River Field Office's Travel and Transportation Management Resource Management Plan Amendment. The sub-group provides recommendations to the Northwest RAC but does not directly advise the BLM. This meeting is open to the public. At this meeting, the sub-group will discuss: introductions of new members; an overview of the travel management planning process within the White River Field Office; and the roles and responsibilities of the sub-group, the RAC and the BLM during this planning effort. The public is able to make oral comments to the sub-group at 2 p.m. or submit written comments for the sub-group's consideration. Summary minutes for the Northwest RAC Travel Management Sub-Group meetings will be maintained in the White River Field Office and will be available for public inspection and reproduction during regular business hours for 30 days following the meeting.

Ruth Welch,

Colorado State Director.

[FR Doc. 2015–26997 Filed 10–22–15; 8:45 am]

BILLING CODE 4310–JB–P

DEPARTMENT OF THE INTERIOR

National Park Service

[NPS–WASO–NRSS–15890; PPWONRADE2.PMP00EI05.YP0000]

Draft Environmental Impact Statement Non-Federal Oil and Gas Regulations

AGENCY: National Park Service, Interior.

ACTION: Notice of availability.

SUMMARY: Pursuant to the National Environmental Policy Act of 1969, 42 U.S.C. 4332(2)(C), the National Park Service (NPS) announces the availability of the Draft Environmental Impact Statement (DEIS) for the Nonfederal Oil and Gas Regulations (36 CFR part 9, subpart B) Revisions.

DATES: The NPS will accept comments on the DEIS from the public for a period of 60 days following publication by the Environmental Protection Agency (EPA) of the Notice of Availability of the Draft Environmental Impact Statement in the **Federal Register**. We will also announce the dates, times and location to solicit public comments on the DEIS through the NPS Planning, Environment, and Public Comment (PEPC) Web site at *http://parkplanning.nps.gov/DEIS9B* and media outlets. A web link to a pre-recorded webinar providing an overview of the project will also be listed.

ADDRESSES: Copies of the DEIS will be available for public review at *http://parkplanning.nps.gov/DEIS9B.* A limited number of hard copies will be available upon request.

FOR FURTHER INFORMATION CONTACT: David Steensen, Chief, Geologic Resource Division, National Park Service, P.O. Box 25287, Denver, CO 80225; phone 303.969.2014.

SUPPLEMENTARY INFORMATION: The DEIS evaluates the impacts of three alternatives, including the following alternative elements:

- Elimination of two regulatory provisions that exempt 60% of the oil and gas operations in NPS units. All operators in NPS units would be required to comply with the 9B regulations.
- Elimination of the financial assurance (bonding) cap. Financial assurance would be equal to the reasonable estimated cost of site reclamation.
- Improving enforcement authority by incorporating existing NPS penalty provisions. Law enforcement staff would have authority to write citations for noncompliance with the regulations.
- Authorizing compensation to the federal government for new access on federal lands outside the boundary of an operator's mineral right.
- Reformatting the regulations to make it easier to identify an operator's information requirements and operating standards that apply to each type of operation.

If you wish to comment electronically, you may submit your comments online at the PEPC Web site by visiting *http://parkplanning.nps.gov/DEIS9B.* NPS encourages commenting electronically through PEPC. The deadline for submitting comments online is midnight, Eastern Time, on the last day of the public comment period, which will be 60 days after the EPA's Notice of Availability for this DEIS is published in the **Federal Register**. You may also submit written comments by mail to: David Steensen, Chief, Geologic Resource Division, National Park Service, P.O. Box 25287, Denver, CO 80225. Comments will not be accepted by fax, email, or in any other way than those specified above. Bulk comments in any format (hard copy or electronic) submitted on behalf of others will not be accepted. 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.

The responsible official for this DEIS is the Associate Director, Natural Resources, Stewardship and Science, 1849 C Street NW., Washington, DC 20240.

Dated: January 15, 2015.

Ray Sauvajot,

Associate Director, Natural Resources, Stewardship and Science, Washington Office, National Park Service.

Editorial Note: This document was received for publication by the Office of the Federal Register on October 20, 2015.

[FR Doc. 2015–26999 Filed 10–22–15; 8:45 am]

BILLING CODE 4312–52–P

DEPARTMENT OF JUSTICE

Bureau of Alcohol, Tobacco, Firearms, and Explosives

[Docket No. 2015R–23]

Commerce in Explosives; 2015 Annual List of Explosive Materials

AGENCY: Bureau of Alcohol, Tobacco, Firearms, and Explosives (ATF); Department of Justice.

ACTION: Notice of list of explosive materials.

SUMMARY: Pursuant to 18 U.S.C. 841(d) and 27 CFR 555.23, the Department must publish and revise at least annually in the **Federal Register** a list of explosives determined to be within the coverage of 18 U.S.C. 841 *et seq*. The list covers not only explosives, but also blasting agents and detonators, all of which are defined as explosive materials in 18 U.S.C. 841(c). This notice publishes the 2015 Annual List of Explosive Materials.

DATES: The list becomes effective October 23, 2015.

FOR FURTHER INFORMATION CONTACT: William E. Frye Jr., Chief, Explosives Industry Programs Branch; Firearms and Explosives Industry Division; Bureau of Alcohol, Tobacco, Firearms, and Explosives; United States Department of Justice; 99 New York Avenue NE., Washington, DC 20226; 202 648–7120.

SUPPLEMENTARY INFORMATION: The list includes all mixtures containing any of the materials on the list. Materials constituting blasting agents are marked by an asterisk. While the list is comprehensive, it is not all-inclusive. The fact that an explosive material is not on the list does not mean that it is not within the coverage of the law if it otherwise meets the statutory definitions in 18 U.S.C. 841. Explosive materials are listed alphabetically by their common names followed, where applicable, by chemical names and synonyms in brackets.

The Department has not added any new terms to the list of explosive materials or removed or revised any listing since its last publication. This list supersedes the List of Explosive Materials dated October 7, 2014 (Docket No. 2014R–25T, 79 FR 60496).

Notice of the 2015 Annual List of Explosive Materials

Pursuant to 18 U.S.C. 841(d) and 27 CFR 555.23, I hereby designate the following as explosive materials covered under 18 U.S.C. 841(c):

A

Acetylides of heavy metals.
Aluminum containing polymeric propellant.
Aluminum ophorite explosive.
Amatex.
Amatol.
Ammonal.
Ammonium nitrate explosive mixtures (cap sensitive).
* Ammonium nitrate explosive mixtures (non-cap sensitive).
Ammonium perchlorate having particle size less than 15 microns.
Ammonium perchlorate explosive mixtures (excluding ammonium perchlorate composite propellant (APCP)).
Ammonium picrate [picrate of ammonia, Explosive D].
Ammonium salt lattice with isomorphously substituted inorganic salts.
* ANFO [ammonium nitrate-fuel oil].
Aromatic nitro-compound explosive mixtures.
Azide explosives.

B

Baranol.
Baratol.
BEAF [1, 2-bis (2, 2-difluoro-2-nitroacetoxyethane)].
Black powder.
Black powder based explosive mixtures.
Black powder substitutes.
*Blasting agents, nitro-carbo-nitrates, including non-cap sensitive slurry and water gel explosives.
Blasting caps.
Blasting gelatin.
Blasting powder.
BTNEC [bis (trinitroethyl) carbonate].
BTNEN [bis (trinitroethyl) nitramine].
BTTN [1,2,4 butanetriol trinitrate].
Bulk salutes.
Butyl tetryl.

C

Calcium nitrate explosive mixture.
Cellulose hexanitrate explosive mixture.
Chlorate explosive mixtures.
Composition A and variations.
Composition B and variations.
Composition C and variations.
Copper acetylide.
Cyanuric triazide.
Cyclonite [RDX].
Cyclotetramethylenetetranitramine [HMX].
Cyclotol.
Cyclotrimethylenetrinitramine [RDX].

D

DATB [diaminotrinitrobenzene].
DDNP [diazodinitrophenol].
DEGDN [diethyleneglycol dinitrate].
Detonating cord.
Detonators.
Dimethylol dimethyl methane dinitrate composition.
Dinitroethyleneurea.
Dinitroglycerine [glycerol dinitrate].
Dinitrophenol.
Dinitrophenolates.
Dinitrophenyl hydrazine.
Dinitroresorcinol.
Dinitrotoluene-sodium nitrate explosive mixtures.
DIPAM [dipicramide; diaminohexanitrobiphenyl].
Dipicryl sulfone.
Dipicrylamine.
Display fireworks.
DNPA [2,2-dinitropropyl acrylate].
DNPD [dinitropentano nitrile].
Dynamite.

E

EDDN [ethylene diamine dinitrate].
EDNA [ethylenedinitramine].
Ednatol.
EDNP [ethyl 4,4-dinitropentanoate].
EGDN [ethylene glycol dinitrate].
Erythritol tetranitrate explosives.
Esters of nitro-substituted alcohols.
Ethyl-tetryl.
Explosive conitrates.
Explosive gelatins.
Explosive liquids.
Explosive mixtures containing oxygen-releasing inorganic salts and hydrocarbons.
Explosive mixtures containing oxygen-releasing inorganic salts and nitro bodies.
Explosive mixtures containing oxygen-releasing inorganic salts and water insoluble fuels.
Explosive mixtures containing oxygen-releasing inorganic salts and water soluble fuels.
Explosive mixtures containing sensitized nitromethane.
Explosive mixtures containing tetranitromethane (nitroform).
Explosive nitro compounds of aromatic hydrocarbons.
Explosive organic nitrate mixtures.
Explosive powders.

F

Flash powder.
Fulminate of mercury.
Fulminate of silver.

Fulminating gold.
Fulminating mercury.
Fulminating platinum.
Fulminating silver.

G

Gelatinized nitrocellulose.
Gem-dinitro aliphatic explosive mixtures.
Guanyl nitrosamino guanyl tetrazene.
Guanyl nitrosamino guanylidene hydrazine.
Guncotton.

H

Heavy metal azides.
Hexanite.
Hexanitrodiphenylamine.
Hexanitrostilbene.
Hexogen [RDX].
Hexogene or octogene and a nitrated N-methylaniline.
Hexolites.
HMTD [hexamethylenetriperoxidediamine].
HMX [cyclo-1,3,5,7-tetramethylene 2,4,6,8-tetranitramine; Octogen].
Hydrazinium nitrate/hydrazine/aluminum explosive system.
Hydrazoic acid.

I

Igniter cord.
Igniters.
Initiating tube systems.

K

KDNBF [potassium dinitrobenzo-furoxane].

L

Lead azide.
Lead mannite.
Lead mononitroresorcinate.
Lead picrate.
Lead salts, explosive.
Lead styphnate [styphnate of lead, lead trinitroresorcinate].
Liquid nitrated polyol and trimethylolethane.
Liquid oxygen explosives.

M

Magnesium ophorite explosives.
Mannitol hexanitrate.
MDNP [methyl 4,4-dinitropentanoate].
MEAN [monoethanolamine nitrate].
Mercuric fulminate.
Mercury oxalate.
Mercury tartrate.
Metriol trinitrate.
Minol-2 [40% TNT, 40% ammonium nitrate, 20% aluminum].
MMAN [monomethylamine nitrate]; methylamine nitrate.
Mononitrotoluene-nitroglycerin mixture.
Monopropellants.

N

NIBTN [nitroisobutametriol trinitrate].
Nitrate explosive mixtures.
Nitrate sensitized with gelled nitroparaffin.
Nitrated carbohydrate explosive.
Nitrated glucoside explosive.
Nitrated polyhydric alcohol explosives.
Nitric acid and a nitro aromatic compound explosive.
Nitric acid and carboxylic fuel explosive.
Nitric acid explosive mixtures.
Nitro aromatic explosive mixtures.
Nitro compounds of furane explosive mixtures.
Nitrocellulose explosive.
Nitroderivative of urea explosive mixture.
Nitrogelatin explosive.
Nitrogen trichloride.
Nitrogen tri-iodide.
Nitroglycerine [NG, RNG, nitro, glyceryl trinitrate, trinitroglycerine].
Nitroglycide.
Nitroglycol [ethylene glycol dinitrate, EGDN].
Nitroguanidine explosives.
Nitronium perchlorate propellant mixtures.
Nitroparaffins Explosive Grade and ammonium nitrate mixtures.
Nitrostarch.
Nitro-substituted carboxylic acids.
Nitrourea.

O

Octogen [HMX].
Octol [75 percent HMX, 25 percent TNT].
Organic amine nitrates.
Organic nitramines.

P

PBX [plastic bonded explosives].
Pellet powder.
Penthrinite composition.
Pentolite.
Perchlorate explosive mixtures.
Peroxide based explosive mixtures.
PETN [nitropentaerythrite, pentaerythrite tetranitrate, pentaerythritol tetranitrate].
Picramic acid and its salts.
Picramide.
Picrate explosives.
Picrate of potassium explosive mixtures.
Picratol.
Picric acid (manufactured as an explosive).
Picryl chloride.
Picryl fluoride.
PLX [95% nitromethane, 5% ethylenediamine].
Polynitro aliphatic compounds.
Polyolpolynitrate-nitrocellulose explosive gels.
Potassium chlorate and lead sulfocyanate explosive.
Potassium nitrate explosive mixtures.
Potassium nitroaminotetrazole.
Pyrotechnic compositions.
Pyrotechnic fuses.
PYX [2,6-bis(picrylamino)] 3,5-dinitropyridine.

R

RDX [cyclonite, hexogen, T4, cyclo-1,3,5,-trimethylene-2,4,6,-trinitramine; hexahydro-1,3,5-trinitro-S-triazine].

S

Safety fuse.
Salts of organic amino sulfonic acid explosive mixture.
Salutes (bulk).
Silver acetylide.
Silver azide.
Silver fulminate.
Silver oxalate explosive mixtures.
Silver styphnate.
Silver tartrate explosive mixtures.
Silver tetrazene.
Slurried explosive mixtures of water, inorganic oxidizing salt, gelling agent, fuel, and sensitizer (cap sensitive).
Smokeless powder.
Sodatol.
Sodium amatol.
Sodium azide explosive mixture.
Sodium dinitro-ortho-cresolate.
Sodium nitrate explosive mixtures.
Sodium nitrate-potassium nitrate explosive mixture.
Sodium picramate.
Special fireworks.
Squibs.
Styphnic acid explosives.

T

Tacot [tetranitro-2,3,5,6-dibenzo-1,3a,4,6a tetrazapentalene].
TATB [triaminotrinitrobenzene].
TATP [triacetonetriperoxide].
TEGDN [triethylene glycol dinitrate].
Tetranitrocarbazole.
Tetrazene [tetracene, tetrazine, 1(5-tetrazolyl)-4-guanyl tetrazene hydrate].
Tetrazole explosives.
Tetryl [2,4,6 tetranitro-N-methylaniline].
Tetrytol.
Thickened inorganic oxidizer salt slurried explosive mixture.
TMETN [trimethylolethane trinitrate].
TNEF [trinitroethyl formal].
TNEOC [trinitroethylorthocarbonate].
TNEOF [trinitroethylorthoformate].
TNT [trinitrotoluene, trotyl, trilite, triton].
Torpex.
Tridite.
Trimethylol ethyl methane trinitrate composition.
Trimethylolthane trinitrate-nitrocellulose.

Trimonite.
Trinitroanisole.
Trinitrobenzene.
Trinitrobenzoic acid.
Trinitrocresol.
Trinitro-meta-cresol.
Trinitronaphthalene.
Trinitrophenetol.
Trinitrophloroglucinol.
Trinitroresorcinol.
Tritonal.

U

Urea nitrate.

W

Water-bearing explosives having salts of oxidizing acids and nitrogen bases, sulfates, or sulfamates (cap sensitive).

Water-in-oil emulsion explosive compositions.

X

Xanthamonas hydrophilic colloid explosive mixture.

Date approved: October 19, 2015.

Thomas E. Brandon,

Acting Director.

[FR Doc. 2015–26994 Filed 10–22–15; 8:45 am]

BILLING CODE 4410–FY–P

DEPARTMENT OF JUSTICE

Antitrust Division

Notice Pursuant to the National Cooperative Research and Production Act of 1993—Petroleum Environmental Research Forum

Notice is hereby given that, on September 22, 2015, pursuant to section 6(a) of the National Cooperative Research and Production Act of 1993, 15 U.S.C. 4301 *et seq.* (''the Act''), Petroleum Environmental Research Forum (''PERF'') has filed written notifications simultaneously with the Attorney General and the Federal Trade Commission disclosing changes in its membership. The notifications were filed for the purpose of extending the Act's provisions limiting the recovery of antitrust plaintiffs to actual damages under specified circumstances. Specifically, Ramboll Environ, Inc., Houston, TX, has been added as a party to this venture.

No other changes have been made in either the membership or planned activity of the group research project. Membership in this group research project remains open, and PERF intends to file additional written notifications disclosing all changes in membership.

On February 10, 1986, PERF filed its original notification pursuant to section 6(a) of the Act. The Department of Justice published a notice in the **Federal Register** pursuant to section 6(b) of the Act on March 14, 1986 (51 FR 8903).

The last notification was filed with the Department on December 9, 2014. A notice was published in the **Federal Register** pursuant to section 6(b) of the Act on January 5, 2015 (80 FR 259).

Patricia A. Brink,

Director of Civil Enforcement, Antitrust Division.

[FR Doc. 2015–27024 Filed 10–22–15; 8:45 am]

BILLING CODE P

DEPARTMENT OF JUSTICE

Antitrust Division

Notice Pursuant to the National Cooperative Research and Production Act of 1993—Cooperative Research Group on Separation Technology Research Program

Notice is hereby given that, on September 22, 2015, pursuant to section 6(a) of the National Cooperative Research and Production Act of 1993, 15 U.S.C. 4301 *et seq.* (''the Act''), Southwest Research Institute—Cooperative Research Group on Separation Technology Research Program (''STAR'') has filed written notifications simultaneously with the Attorney General and the Federal Trade Commission disclosing changes in its membership. The notifications were filed for the purpose of extending the Act's provisions limiting the recovery of antitrust plaintiffs to actual damages under specified circumstances. Specifically, Technip USA, Inc., Houston, TX; GE Oil & Gas, Sandvika, NORWAY; Single Buoy Moorings, Inc., Marly, SWITZERLAND; and Aker Subsea AS, Fornebu, NORWAY, have been added as parties to this venture.

Also, PetroSkills, LLC, Katy, TX, has withdrawn as a party to this venture.

No other changes have been made in either the membership or planned activity of the group research project. Membership in this group research project remains open, and STAR intends to file additional written notifications disclosing all changes in membership.

On August 8, 2014, STAR filed its original notification pursuant to section 6(a) of the Act. The Department of Justice published a notice in the **Federal Register** pursuant to section 6(b) of the Act on September 8, 2014 (79 FR 53215).

The last notification was filed with the Department on May 15, 2015. A notice was published in the **Federal Register** pursuant to section 6(b) of the Act on June 8, 2015 (80 FR 32411).

Patricia A. Brink,

Director of Civil Enforcement, Antitrust Division.

[FR Doc. 2015–27045 Filed 10–22–15; 8:45 am]

BILLING CODE P

DEPARTMENT OF JUSTICE

Antitrust Division

Notice Pursuant to the National Cooperative Research and Production Act of 1993—Advanced Media Workflow Association, Inc.

Notice is hereby given that, on September 24, 2015, pursuant to section 6(a) of the National Cooperative Research and Production Act of 1993, 15 U.S.C. 4301 *et seq.* (''the Act''), Advanced Media Workflow Association, Inc. has filed written notifications simultaneously with the Attorney General and the Federal Trade Commission disclosing changes in its membership. The notifications were filed for the purpose of extending the Act's provisions limiting the recovery of antitrust plaintiffs to actual damages under specified circumstances. Specifically, Australia Broadcasting Corporation, Sydney, AUSTRALIA; Encompass Digital Media, Stamford, CT; InSync Technology Ltd., Petersfield, UNITED KINGDOM; Snell Advanced Media, Newbury, Berkshire, UNITED KINGDOM; TVNZ, Auckland, NEW ZEALAND; and YLE, Helsinki, FINLAND, have been added as parties to this venture.

Also, Aframe, London, UNITED KINGDOM; Extreme Reach, Dallas, TX; Marquis Broadcast, Pangbourne, UNITED KINGDOM; Quantel Ltd., Newbury, Berkshire, UNITED KINGDOM; John A. Hoehn (individual member), Pennsville, NJ; and John Warburton (individual member), Montreal, CANADA, have withdrawn as parties to this venture.

No other changes have been made in either the membership or planned activity of the group research project. Membership in this group research project remains open, and Advanced Media Workflow Association, Inc. intends to file additional written notifications disclosing all changes in membership.

On March 28, 2000, Advanced Media Workflow Association, Inc. filed its original notification pursuant to section 6(a) of the Act. The Department of Justice published a notice in the **Federal Register** pursuant to section 6(b) of the Act on June 29, 2000 (65 FR 40127).

The last notification was filed with the Department on June 19, 2015. A notice was published in the **Federal Register** pursuant to section 6(b) of the Act on July 17, 2015 (80 FR 42538).

Patricia A. Brink,

Director of Civil Enforcement, Antitrust Division.

[FR Doc. 2015–27046 Filed 10–22–15; 8:45 am]

BILLING CODE P

DEPARTMENT OF JUSTICE

Antitrust Division

Notice Pursuant to the National Cooperative Research and Production Act of 1993—Sematech, Inc. D/B/A International Sematech

Notice is hereby given that, on September 22, 2015, pursuant to section 6(a) of the National Cooperative Research and Production Act of 1993, 15 U.S.C. 4301 *et seq.* (''the Act''), Sematech, Inc. d/b/a International Sematech (''SEMATECH'') has filed written notifications simultaneously with the Attorney General and the Federal Trade Commission disclosing changes in its membership. The notifications were filed for the purpose of extending the Act's provisions limiting the recovery of antitrust plaintiffs to actual damages under specified circumstances. Specifically, SCREEN Semiconductor Solutions Co., Ltd., Kyoto, JAPAN; and Veeco Instruments Inc., Plainview, NY, have been added as parties to this venture.

Also, Silvaco, Inc., Santa Clara, CA; Yonsei University, Seoul, REPUBLIC OF KOREA; Inpria Corporation, Corvallis, OR; Shin Etsu Chemical Co., Ltd., Tokyo, JAPAN; Rion Co., Ltd., Tokyo, JAPAN; AIXTRON SE., Herzogenrath, GERMANY; Nova Measuring Instruments, Ltd., Rehovot, ISRAEL; and Conexant Systems, Inc., Irvine, CA, have withdrawn as parties to this venture.

No other changes have been made in either the membership or planned activity of the group research project. Membership in this group research project remains open, and SEMATECH intends to file additional written notifications disclosing all changes in membership.

On April 22, 1988, SEMATECH filed its original notification pursuant to section 6(a) of the Act. The Department of Justice published a notice in the **Federal Register** pursuant to section 6(b) of the Act on May 19, 1988 (53 FR 17987).

The last notification was filed with the Department on June 23, 2015. A notice was published in the **Federal Register** pursuant to section 6(b) of the Act on July 17, 2015 (80 FR 42538).

Patricia A. Brink,

Director of Civil Enforcement, Antitrust Division.

[FR Doc. 2015–27081 Filed 10–22–15; 8:45 am]

BILLING CODE P

DEPARTMENT OF JUSTICE

Antitrust Division

Notice Pursuant to the National Cooperative Research and Production Act of 1993—AllSeen Alliance, Inc.

Notice is hereby given that, on September 23, 2015, pursuant to section 6(a) of the National Cooperative Research and Production Act of 1993, 15 U.S.C. 4301 *et seq.* (''the Act''), AllSeen Alliance, Inc. (''AllSeen Alliance'') has filed written notifications simultaneously with the Attorney General and the Federal Trade Commission disclosing changes in its membership. The notifications were filed for the purpose of extending the Act's provisions limiting the recovery of antitrust plaintiffs to actual damages under specified circumstances. Specifically, OmniM2M LLC, Bellevue, WA; ShenZhen Topeast Technology Co., Ltd., Nanshan District, Shenzhen, PEOPLE'S REPUBLIC OF CHINA; Visible Energy Inc., Palo Alto, CA; Fabita s.r.l., S. Quirico (AN), ITALY; Pivotal Software, Inc., Palo Alto, CA; Micosa, Inc., Redwood City, CA; Koninklijke Philips N.V., AE Eindhoven, THE NETHERLANDS; Radialpoint Safecare Inc., Montreal, Quebec, CANADA; Lowe's Companies, Inc., Mooresville, NC; Johnson Controls, Milwaukee, WI; Rakuten, Inc., Shinagawa-ku, Tokyo, JAPAN; TA Technology (Shanghai) Co., Ltd., Shanghai, PEOPLE'S REPUBLIC OF CHINA; sMedio, Inc., Minato-ku, Tokyo, JAPAN; Walter Kidde Portables, LLC, Mebane, NC; Buffalo Inc., Naka-ku, Nagoya, JAPAN; and Beijing HengShengDongYang Technology Co., Ltd., ChaoYang District, Beijing, PEOPLE'S REPUBLIC OF CHINA, have been added as parties to this venture.

Also, Harman International, Stamford, CT; Local Motors, Chandler, AZ; Octoblu, Inc., Tempe, AZ; Vedams, Inc., San Jose, CA; MachineShop, Inc., Boston, MA; ControlBEAM Digital Automation, Irvine, CA; ISI Technology, Charleston, SC; Tellient, San Diego, CA; Ciseco, Nottingham, UNITED KINGDOM; Discretix Technologies Ltd., Kfar Netter, ISRAEL; and Yifang Digital Technology Co., Ltd., Shenzhen, PEOPLE'S REPUBLIC OF CHINA, have withdrawn as parties to this venture.

No other changes have been made in either the membership or planned activity of the group research project. Membership in this group research project remains open, and AllSeen Alliance intends to file additional written notifications disclosing all changes in membership.

On January 29, 2014, AllSeen Alliance filed its original notification pursuant to section 6(a) of the Act. The Department of Justice published a notice in the **Federal Register** pursuant to section 6(b) of the Act on March 4, 2014 (79 FR 12223).

The last notification was filed with the Department on July 13, 2015. A notice was published in the **Federal Register** pursuant to section 6(b) of the Act on July 29, 2015 (80 FR 45235).

Patricia A. Brink,

Director of Civil Enforcement, Antitrust Division.

[FR Doc. 2015–27043 Filed 10–22–15; 8:45 am]

BILLING CODE 4410–11–P

DEPARTMENT OF JUSTICE

Antitrust Division

Notice Pursuant to the National Cooperative Research and Production Act of 1993—Cooperative Research Group on Advanced Engine Fluids

Notice is hereby given that, on September 22, 2015, pursuant to section 6(a) of the National Cooperative Research and Production Act of 1993, 15 U.S.C. 4301 *et seq.* (''the Act''), Southwest Research Institute—Cooperative Research Group on Advanced Engine Fluids (''AEF'') has filed written notifications simultaneously with the Attorney General and the Federal Trade Commission disclosing changes in its membership. The notifications were filed for the purpose of extending the Act's provisions limiting the recovery of antitrust plaintiffs to actual damages under specified circumstances. Specifically, Fuchs Europe Schierstoffe GMBH, Mannheim, GERMANY; Afton Chemical Corporation, Richmond, VA; and Lubrizol, Wickliffe, OH, have been added as parties to this venture.

No other changes have been made in either the membership or planned activity of the group research project. Membership in this group research project remains open, and AEF intends to file additional written notifications disclosing all changes in membership.

On March 20, 2015, AEF filed its original notification pursuant to section

6(a) of the Act. The Department of Justice published a notice in the **Federal Register** pursuant to section 6(b) of the Act on April 22, 2015 (80 FR 22551).

The last notification was filed with the Department on May 19, 2015. A notice was published in the **Federal Register** pursuant to section 6(b) of the Act on June 8, 2015 (80 FR 32411).

Patricia A. Brink,

Director of Civil Enforcement, Antitrust Division.

[FR Doc. 2015–27044 Filed 10–22–15; 8:45 am]

BILLING CODE P

DEPARTMENT OF JUSTICE

Antitrust Division

Notice Pursuant to the National Cooperative Research and Production Act of 1993—Members of SGIP 2.0, Inc.

Notice is hereby given that, on September 25, 2015, pursuant to section 6(a) of the National Cooperative Research and Production Act of 1993, 15 U.S.C. 4301 *et seq.* (''the Act''), Members of SGIP 2.0, Inc. (''MSGIP 2.0'') has filed written notifications simultaneously with the Attorney General and the Federal Trade Commission disclosing changes in its membership. The notifications were filed for the purpose of extending the Act's provisions limiting the recovery of antitrust plaintiffs to actual damages under specified circumstances. Specifically, Coergon, Boulder, CO; CleanSpark LLC, Poway, CA; Minnesota Public Utilities Commission, St. Paul, MN; Indra Systems Inc., Miami, FL; Energy Surety Partners LLC, Phoenix, AZ; and Jamaica Public Service Company Ltd., Kingston 5, JAMAICA, have been added as parties to this venture.

Also, Gas Technology Institute, Des Moines, IA; MidAmerican Energy Company, Davenport, IA; Opower, Arlington, VA; Businovation, LLC, Basking Ridge, NJ; and Machine-to-Machine Intelligence Corporation (M2Mi), Moffett Field, CA, have withdrawn as parties to this venture.

No other changes have been made in either the membership or planned activity of the group research project. Membership in this group research project remains open, and MSGIP 2.0 intends to file additional written notifications disclosing all changes in membership.

On February 5, 2013, MSGIP 2.0 filed its original notification pursuant to section 6(a) of the Act. The Department of Justice published a notice in the **Federal Register** pursuant to section 6(b) of the Act on March 7, 2013 (78 FR 14836).

The last notification was filed with the Department on June 29, 2015. A notice was published in the **Federal Register** pursuant to section 6(b) of the Act on July 29, 2015 (80 FR 45233).

Patricia A. Brink,

Director of Civil Enforcement, Antitrust Division.

[FR Doc. 2015–27040 Filed 10–22–15; 8:45 am]

BILLING CODE P

DEPARTMENT OF LABOR

Employment and Training Administration

Comment Request for Information Collection on Employment and Training (ET) Handbook 361, Unemployment Insurance (UI) Data Validation (DV), Extension With Revisions

AGENCY: Employment and Training Administration (ETA), Labor.

ACTION: Notice.

SUMMARY: The Department of Labor (Department), as part of its continuing effort to reduce paperwork and respondent burden, conducts a preclearance consultation program to provide the public and Federal agencies with an opportunity to comment on proposed and/or continuing collections of information in accordance with the Paperwork Reduction Act of 1995 [44 U.S.C. 3506(c)(2)(A)]. This program helps 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.

Currently, ETA is soliciting comments concerning the collection of data for the UI DV program. Collection authority for this program expires May 31, 2016.

DATES: Submit written comments to the office listed in the addresses section below on or before December 22, 2015.

ADDRESSES: Send written comments to Rachel Beistel, Room S–4519, Employment and Training Administration, U.S. Department of Labor, 200 Constitution Avenue NW., Washington, DC 20210. Telephone number: 202–693–2736 (this is not a toll-free number). Individuals with hearing or speech impairments may access the telephone number above via TTY by calling the toll-free Federal Information Relay Service at 1–877–889–5627 (TTY/TDD). Email: *Beistel.Rachel@dol.gov.* To obtain a copy of the proposed information collection request (ICR), please contact the person listed above.

SUPPLEMENTARY INFORMATION:

I. Background

Section 303(a)(6) of the Social Security Act specifies that the Secretary of Labor will not certify State UI programs to receive administrative grants unless the State's law includes provisions for: making of such reports . . . as the Secretary of Labor may from time to time require, and compliance with such provisions as the Secretary may from time to time find necessary to assure the correctness and verification of such reports.

The Department considers data validation one of those ''provisions . . . necessary to assure the correctness and verification'' of the reports it requires.

The Government Performance and Results Act of 1993 (GPRA) requires Federal agencies to develop annual and strategic performance plans that establish performance goals, have concrete indicators of the extent that goals are achieved, and set performance targets. Each year, the agency is to issue a report that ''evaluate[s] the performance plan for the current fiscal year relative to the performance achieved toward the performance goals in the fiscal year covered by the report.'' Section 1116 (d)(2) of OMB Circular A–11, which implements the GPRA process, cites the Reports Consolidation Act of 2000 to emphasize the need for data validation by requiring that the agency's annual performance report ''contain an assessment of the completeness and reliability of the performance data included in it [that] . . . describes any material inadequacies in the completeness and reliability of the data.'' (OMB Circular A–11, Section 230.2 (f)). The Department emphasizes the importance of complete and accurate information for program monitoring and improving program performance.

The UI DV program employs a refined and automated approach to review 322 elements reported on 13 benefits reports and one tax report. The Department uses many of these elements for key performance measures as well as for workload analysis.

The validation process assesses the validity (accuracy) of the counts of transactions or measurements of status as follows. Guided by a detailed handbook, the state first constructs extract files containing all pertinent individual transactions for the desired report period to be validated. These transactions are grouped into 16 benefits and five tax populations. Each transaction record contains the necessary characteristics or dimensions that enable it to be summed into an independent recount of what the state has already reported. The Department provides state agencies with software that edits the extract file (to identify and remove duplicate transactions and improperly built records, for example), then aggregates the transactions to produce an independent reconstruction or ''validation count'' of the reported figure. The reported count is considered valid by this ''quantity'' validation test if it is within ±2% of the validation count (±1% for a GPRA-related element).

The software also draws samples of most transaction types from the extract files. Guided by a state-specific handbook, the validators review these sample records against documentation in the state's management information system to determine whether the transactions in the extract file are supported by system documentation. This qualitative check determines whether the validation count can be trusted as accurate. The benefits extract files are considered to pass this ''quality'' review if random samples indicate that no more than 5% of the records contain errors; tax files are subjected to different but related tests. A reported count is considered valid only if it differs from a reconstructed (validation) count by no more than the appropriate criterion of ±2% or ±1%, and the validation count comes from an extract file that has satisfied all quality tests.

For Federal fiscal years 2011 and beyond, all states will be required to conduct a complete validation every three years. In three cases the three-year rule does not apply, and a revalidation must occur within one year: (1) Groups of reported counts that are summed for purposes of making a Pass/Fail determination and do not pass validation by being within ±2% of the reconstructed counts or the extract file does not pass all quality tests; (2) the validation applies to the two benefits populations and one tax population used for GPRA measures; and (3) reports are produced by new reporting software. Every year states must also certify that Module 3 of the Benefits and Tax handbooks are up to date.

In August 2015, through Unemployment Insurance Program Letter 08–12, Change 1, the Department issued changes that increased the high dollar overpayment threshold from $5,000 to $25,000 on the ETA 227 report. The ETA 227 report is validated through four of the 16 benefit populations. Only the validation of Benefits Population 12 will be affected by the new threshold of $25,000. Accommodating the new threshold requires: (1) Changing the threshold amount in the data validation database programming; (2) making one-time changes to two rows of data that validate the 227 report; and (3) adapting the affected Overpayment rules (called Steps or Substeps) to Module 3 of the Benefits handbook, which contains State definitions and data system locations for Federal reporting requirements. These changes will impose little to no additional burden on state validators.

II. Review Focus

The Department 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;

• 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;

• Enhance the quality, utility, and clarity of the information to be collected; and

• 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

Type of Review: Extension with revisions.

Title: Unemployment Insurance Data Validation Program.

OMB Number: 1205–0431.

Affected Public: State Workforce Agencies.

Form(s): ET Handbook 361.

Estimated Total Annual Respondents: 53.

Annual Frequency: At least five validation items per state (two benefits populations and one tax population) plus reviewing and certifying that Benefits and Tax Module items are up to date.

Estimated Total Annual Responses: 265 (53 states × 5 populations).

Average Time per Response: 446 Hours.

Estimated Total Annual Burden Hours: 23,644 Hours.

Total Annual Burden Cost for Respondents: $1,115,997.

We will summarize and/or include in the request for OMB approval of the ICR, the comments received in response to this comment request; they will also become a matter of public record.

Portia Wu,

Assistant Secretary for Employment and Training, Labor.

[FR Doc. 2015–26944 Filed 10–22–15; 8:45 am]

BILLING CODE 4510–FW–P

DEPARTMENT OF LABOR

Office of the Secretary

Agency Information Collection Activities; Submission for OMB Review; Comment Request; Prohibited Transaction Exemption 1990–1, Insurance Company Pooled Separate Accounts

ACTION: Notice.

SUMMARY: The Department of Labor (DOL) is submitting the Employee Benefits Security Administration (EBSA) sponsored information collection request (ICR) titled, ''Prohibited Transaction Exemption 1990–1, Insurance Company Pooled Separate Accounts,'' to the Office of Management and Budget (OMB) for review and approval for continued use, without change, in accordance with the Paperwork Reduction Act of 1995 (PRA), 44 U.S.C. 3501 *et seq.* Public comments on the ICR are invited.

DATES: The OMB will consider all written comments that agency receives on or before November 23, 2015.

ADDRESSES: A copy of this ICR with applicable supporting documentation; including a description of the likely respondents, proposed frequency of response, and estimated total burden may be obtained free of charge from the RegInfo.gov Web site at *http://www.reginfo.gov/public/do/PRAViewICR?ref_nbr=201509-1210-001* (this link will only become active on the day following publication of this notice) or by contacting Michel Smyth by telephone at 202–693–4129, TTY 202–693–8064, (these are not toll-free numbers) or by email at *DOL_PRA_PUBLIC@dol.gov.*

Submit comments about this request by mail or courier to the Office of Information and Regulatory Affairs, Attn: OMB Desk Officer for DOL–EBSA, Office of Management and Budget, Room 10235, 725 17th Street NW., Washington, DC 20503; by Fax: 202–395–5806 (this is not a toll-free number); or by email: *OIRA_submission@omb.eop.gov.* Commenters are encouraged, but not required, to send a courtesy copy of any comments by mail or courier to the U.S. Department of Labor-OASAM, Office of the Chief Information Officer, Attn: Departmental Information Compliance Management Program, Room N1301, 200 Constitution Avenue NW., Washington, DC 20210; or by email: *DOL_PRA_PUBLIC@dol.gov*.

FOR FURTHER INFORMATION CONTACT: Michel Smyth by telephone at 202–693–4129, TTY 202–693–8064, (these are not toll-free numbers) or by email at *DOL_PRA_PUBLIC@dol.gov*.

Authority: 44 U.S.C. 3507(a)(1)(D).

SUPPLEMENTARY INFORMATION: This ICR seeks to extend PRA authority for the Prohibited Transaction Exemption 1990–1 (PTE 90–1), Insurance Company Pooled Separate Accounts information collection. PTE 90–1 provides an exemption from certain Employee Retirement Income Security Act of 1974 (ERISA) provisions relating to transactions involving insurance company pooled separate accounts in which employee benefit plans participate. Without the exemption, Internal Revenue Code section 4975(c)(1) and ERISA sections 406 and 407(a) might prohibit a party in interest to a plan from furnishing goods or services to an insurance company pooled separate account in which the plan has an interest or prohibit engaging in other transactions. *See* 26 U.S.C. 4975(c)(1) and 29 U.S.C. 1106 and 1107(a). Under the exemption, a person who is a party in interest to a plan that invests in a pooled separate account, such as a service provider, may engage in otherwise prohibited transactions with the separate account if the plan's participation in the separate account does not exceed specified limits and other conditions are met. These other conditions include a requirement that the party in interest not be the insurance company, or an affiliate thereof, that holds the plan assets in its pooled separate account or other separate account. The terms of the transaction to which the exemption is applied must be at least as favorable to the pooled separate account as those that would be obtained in a separate arms-length transaction with an unrelated party, and the insurance company must maintain records of any transaction to which the exemption applies for a period of six years. This ICR covers the recordkeeping requirement. Internal Revenue Code section 4975(c)(2) and ERISA section 408(a) authorize this information collection. *See* 26 U.S.C. 4975(c)(2) and 29 U.S.C. 1108(a).

This information collection is subject to the PRA. A Federal agency generally cannot conduct or sponsor a collection of information, and the public is generally not required to respond to an information collection, unless it is approved by the OMB under the PRA and displays a currently valid OMB Control Number. In addition, notwithstanding any other provisions of law, no person shall generally be subject to penalty for failing to comply with a collection of information that does not display a valid Control Number. *See* 5 CFR 1320.5(a) and 1320.6. The DOL obtains OMB approval for this information collection under Control Number 1210–0083.

OMB authorization for an ICR cannot be for more than three (3) years without renewal, and the current approval for this collection is scheduled to expire on October 31, 2015. The DOL seeks to extend PRA authorization for this information collection for three (3) more years, without any change to existing requirements. The DOL notes that existing information collection requirements submitted to the OMB receive a month-to-month extension while they undergo review. For additional substantive information about this ICR, see the related notice published in the **Federal Register** on June 17, 2015 (80 FR 34696).

Interested parties are encouraged to send comments to the OMB, Office of Information and Regulatory Affairs at the address shown in the **ADDRESSES** section within thirty (30) days of publication of this notice in the **Federal Register**. In order to help ensure appropriate consideration, comments should mention OMB Control Number 1210–0083. The OMB is particularly interested in comments that:

- 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;
- 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;
- Enhance the quality, utility, and clarity of the information to be collected; and
- Minimize the burden of the collection of information on those who are to respond, including through the use of appropriate automated, electronic, mechanical, or other technological collection techniques or other forms of information technology, *e.g.,* permitting electronic submission of responses.

Agency: DOL–EBSA.

Title of Collection: Prohibited Transaction Exemption 90–1; Insurance Company Pooled Separate Accounts.

OMB Control Number: 1210–0083.

Affected Public: Private Sector—businesses or other for-profits.

Total Estimated Number of Respondents: 96.

Total Estimated Number of Responses: 960.

Total Estimated Annual Time Burden: 160 hours.

Total Estimated Annual Other Costs Burden: $0.

Dated: October 19, 2015.

Michel Smyth,

Departmental Clearance Officer.

[FR Doc. 2015–26967 Filed 10–22–15; 8:45 am]

BILLING CODE 4510–29–P

NATIONAL FOUNDATION ON THE ARTS AND THE HUMANITIES

National Endowment for the Arts

Proposed Collection; Comment Request

ACTION: Notice.

SUMMARY: The National Endowment for the Arts (NEA), as part of its continuing effort to reduce paperwork and respondent burden, conducts a preclearance consultation program to provide the general public and Federal agencies with an opportunity to comment on proposed and/or continuing collections of information in accordance with the Paperwork Reduction Act of 1995 (PRA95) [44 U.S.C. 3506(c)(A)]. 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. Currently, the NEA is soliciting comments concerning the proposed information collection on arts participation in the U.S. A copy of the current information collection request can be obtained by contacting the office listed below in the address section of this notice.

DATES: Written comments must be submitted to the office listed in the address section below within 60 days from the date of this publication in the **Federal Register**. The NEA 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;

• 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;

• Enhance the quality, utility, and clarity of the information to be collected; and

• 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.

ADDRESSES: Send comments to: Sunil Iyengar, National Endowment for the Arts, 400 7th Street SW., Washington, DC 20506–0001, telephone (202) 682–5424 (this is not a toll-free number), fax (202) 682–5677, or send via email to *research@arts.gov*

Dated: October 19, 2015.

Kathy Plowitz-Worden,

Panel Coordinator, National Endowment for the Arts.

[FR Doc. 2015–26876 Filed 10–22–15; 8:45 am]

BILLING CODE 7537–01–P

NUCLEAR REGULATORY COMMISSION

[NRC–2015–0141]

Information Collection: Exemptions and Continued Regulatory Authority in Agreement States and in Offshore Waters Under Section 274

AGENCY: Nuclear Regulatory Commission.

ACTION: Notice of submission to the Office of Management and Budget; request for comment.

SUMMARY: The U.S. Nuclear Regulatory Commission (NRC) has recently submitted a request for renewal of an existing collection of information to the Office of Management and Budget (OMB) for review. The information collection is entitled, ''Exemptions and Continued Regulatory Authority in Agreement States and in Offshore Waters Under Section 274.''

DATES: Submit comments by November 23, 2015.

ADDRESSES: Submit comments directly to the OMB reviewer at: Vlad Dorjets, Desk Officer, Office of Information and Regulatory Affairs (3150–0032), NEOB–10202, Office of Management and Budget, Washington, DC 20503; telephone: 202–395–7315, email: *oira_submission@omb.eop.gov.*

FOR FURTHER INFORMATION CONTACT: Tremaine Donnell, NRC Clearance Officer, U.S. Nuclear Regulatory Commission, Washington, DC 20555–0001; telephone: 301–415–6258; email: *INFOCOLLECTS.Resource@nrc.gov.*

SUPPLEMENTARY INFORMATION:

I. Obtaining Information and Submitting Comments

A. Obtaining Information

Please refer to Docket ID NRC–2015–0141 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–2015–0141.

• *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 supporting statement is available in ADAMS under Accession No. ML15258A181.

• *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.

• *NRC's Clearance Officer:* A copy of the collection of information and related instructions may be obtained without charge by contacting the NRC's Clearance Officer, Tremaine Donnell, Office of Information Services, U.S. Nuclear Regulatory Commission, Washington, DC 20555–0001; telephone: 301–415–6258; email: *INFOCOLLECTS.Resource@NRC.GOV.*

B. Submitting Comments

The NRC cautions you not to include identifying or contact information in comment submissions that you do not want to be publicly disclosed in your comment submission. All comment submissions are posted at *http://www.regulations.gov* and entered into ADAMS. Comment submissions are not routinely edited to remove identifying or contact information.

If you are requesting or aggregating comments from other persons for submission to the OMB, 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 comment submissions are not routinely edited to remove such information before making the comment submissions available to the public or entering the comment into ADAMS.

II. Background

Under the provisions of the Paperwork Reduction Act of 1995 (44 U.S.C. Chapter 35), the NRC recently submitted a request for renewal of an existing collection of information to OMB for review entitled, ''Exemptions and Continued Regulatory Authority in Agreement States and in Offshore Waters Under Section 274.'' The NRC hereby informs potential respondents that an agency may not conduct or sponsor, and that a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number.

The NRC published a **Federal Register** notice with a 60-day comment period on this information collection on June 17, 2015, 80 FR 34707.

1. *The title of the information collection:* 10 CFR part 150, ''Exemptions and Continued Regulatory Authority in Agreement States and in Offshore Waters Under Section 274.''

2. *OMB approval number:* 3150–0032.

3. *Type of submission:* Extension.

4. *The form number if applicable:* N/A.

5. *How often the collection is required or requested:* Sections 150.16(b), 150.17(c), and 150.19(c) of title 10 of the *Code of Federal Regulations* (10 CFR), require the submission of reports following specified events, such as the theft or unlawful diversion of licensed radioactive material. The source material inventory reports required under 10 CFR 150.17(b) must be submitted annually by certain licensees.

6. *Who will be required or asked to respond:* Agreement State licensees authorized to possess source or special nuclear material at certain types of facilities, or at any one time and location in greater than specified amounts. In addition, persons engaging in activities in non-Agreement States, in areas of exclusive Federal jurisdiction within Agreement States, or in offshore waters.

7. *The estimated number of annual responses:* 8.

8. *The estimated number of annual respondents:* 8.

9. *An estimate of the total number of hours needed annually to comply with the information collection requirement or request:* 190.

10. *Abstract:* Part 150 provides certain exemptions from NRC regulations for persons in Agreement States. Part 150 also defines activities in Agreement States and in offshore waters over which the NRC regulatory authority continues, including certain information collection requirements. The information is needed to permit the NRC to make reports to other governments and the International Atomic Energy Agency in accordance with international agreements. The information is also used to carry out the NRC's safeguards and inspection programs.

Dated at Rockville, Maryland, this 20th day of October 2015.

For the Nuclear Regulatory Commission.

Kristen Benney,

Acting NRC Clearance Officer, Office of Information Services.

[FR Doc. 2015–27064 Filed 10–22–15; 8:45 am]

BILLING CODE 7590–01–P

PENSION BENEFIT GUARANTY CORPORATION

Proposed Submission of Information Collection for OMB Review; Comment Request; Locating and Paying Participants

AGENCY: Pension Benefit Guaranty Corporation.

ACTION: Notice of intent to request OMB approval of modifications to information collection.

SUMMARY: The Pension Benefit Guaranty Corporation (''PBGC'') intends to request that the Office of Management and Budget (''OMB'') approve modifications to a collection of information under the Paperwork Reduction Act. The purpose of the information collection is to enable the PBGC to pay benefits to participants and beneficiaries. This notice informs the public of PBGC's intent and solicits public comment on the collection of information, as modified.

DATES: Comments should be submitted by December 22, 2015.

ADDRESSES: Comments may be submitted by any of the following methods:

Federal eRulemaking Portal: http://www.regulations.gov. Follow the Web site instructions for submitting comments.

Email: paperwork.comments@pbgc.gov.

Fax: 202–326–4224.

Mail or Hand Delivery: Office of the General Counsel, Pension Benefit Guaranty Corporation, 1200 K Street NW., Washington, DC 20005–4026.

PBGC will make all comments available on its Web site at *www.pbgc.gov.*

Copies of the collection of information may be obtained without charge by writing to the Disclosure Division of the Office of the General Counsel of PBGC at the above address or by visiting that office or calling 202–326–4040 during normal business hours. (TTY and TDD users may call the Federal relay service toll-free at 1–800–877–8339 and ask to be connected to 202–326–4040.) The regulations relating to this collection of information are available on PBGC's Web site at *www.pbgc.gov* .

FOR FURTHER INFORMATION CONTACT: Jo Amato Burns, Attorney, Office of the General Counsel, Pension Benefit Guaranty Corporation, 1200 K Street NW., Washington, DC 20005–4026, 202–326–4400. (For TTY and TDD, call 800–877–8339 and ask to be connected to 202–326–4400.)

SUPPLEMENTARY INFORMATION: PBGC intends to request that OMB approve modifications to a collection of information needed to pay participants and beneficiaries who may be entitled to pension benefits under defined benefit plans that have terminated. The collection consists of information participants and beneficiaries are asked to provide in connection with an application for benefits. In addition, in some instances, as part of an effort to identify participants and beneficiaries who may be entitled to benefits, PBGC requests individuals to provide identifying information that the individual would provide as part of an initial contact with PBGC. All requested information is needed to enable PBGC to determine benefit entitlements and to make appropriate payments.

The information collection includes My Pension Benefit Account (My PBA), an application on PBGC's Web site, *http://www.pbgc.gov,* through which plan participants and beneficiaries may conduct electronic transactions with PBGC, including applying for pension benefits, designating a beneficiary, granting a power of attorney, electing monthly payments, electing to withhold income tax from periodic payments, changing contact information, and applying for electronic direct deposit.

PBGC is proposing to add a new form to the information collection: Form XXX, Benefit Inquiry Questionnaire. PBGC will send this form to individuals who contact PBGC to inquire whether PBGC is holding any benefits to which they are entitled. The questionnaire will request information that PBGC needs to determine whether the individual is owed benefits and, if so, the benefit amount.

In addition, PBGC is making clarifying, simplifying, editorial, and other changes to other forms in the information collection.

The existing collection of information under the regulation was approved under OMB control number 1212–0055 (expires December 31, 2015). PBGC intends to request that OMB extend its approval (with modifications) for three years. 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.

PBGC estimates the total annual burden associated with this collection of information will be 73,000 hours and $1,900.

PBGC is soliciting public comments to—

- Evaluate whether the collection of information is necessary for the proper performance of the functions of the agency, including whether the information will have practical utility;
- 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;
- Enhance the quality, utility, and clarity of the information to be collected; and
- Minimize the burden of the collection of information on those who are to respond, including the use of appropriate automated, electronic, mechanical, or other technological collection techniques or other forms of information technology, *e.g.,* permitting electronic submission of responses.

Issued in Washington, DC, this 20th day of October, 2015.

Judith Starr,

General Counsel, Pension Benefit Guaranty Corporation.

[FR Doc. 2015–27083 Filed 10–22–15; 8:45 am]

BILLING CODE 7709–02–P

OFFICE OF PERSONNEL MANAGEMENT

[SF 2809, 3206–0160]

Submission for Review: Health Benefits Election Form

AGENCY: Office of Personnel Management.

ACTION: 30-Day notice and request for comments.

SUMMARY: The Healthcare & Insurance/Federal Employee Insurance Operations (FEIO), Office of Personnel Management (OPM) offers the general public and other federal agencies the opportunity to comment on a revised information collection request (ICR) 3206–0160, Health Benefits Election Form. As required by the Paperwork Reduction Act of 1995, (Pub. L. 104–13, 44 U.S.C. chapter 35) as amended by the Clinger-Cohen Act (Pub. L. 104–106), OPM is soliciting comments for this collection. The information collection was previously published in the **Federal Register** on June 10, 2015 at Volume 80 FR 32994 allowing for a 60-day public comment period. No comments were received for this information collection. The purpose of this notice is to allow an additional 30 days for public comments.

DATES: Comments are encouraged and will be accepted until November 23, 2015. This process is conducted in accordance with 5 CFR 1320.1.

ADDRESSES: Interested persons are invited to submit written comments on the proposed information collection to the Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th Street NW., Washington, DC 20503, Attention: Desk Officer for the Office of Personnel Management or sent via electronic mail to *oira_submission@omb.eop.gov* or faxed to (202) 395–6974.

FOR FURTHER INFORMATION CONTACT: A copy of this ICR, with applicable supporting documentation, may be obtained by contacting the Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th Street NW., Washington, DC 20503, Attention: Desk Officer for the Office of Personnel Management or sent via electronic mail to *oira_submission@omb.eop.gov* or faxed to (202) 395–6974.

SUPPLEMENTARY INFORMATION: The Office of Management and Budget is particularly interested in comments that:

1. Evaluate whether the proposed collection of information is necessary for the proper performance of the functions of the agency, including whether the information will have practical utility;
2. Evaluate the accuracy of the agency's estimate of the burden of the proposed collection of information, including the validity of the methodology and assumptions used;
3. Enhance the quality, utility, and clarity of the information to be collected; and
4. Minimize the burden of the collection of information on those who are to respond, including through the use of appropriate automated, electronic, mechanical, or other technological collection techniques or other forms of information technology, *e.g.,* permitting electronic submissions of responses.

The Health Benefits Election Form is used by Federal employees, annuitants other than those under the Civil Service Retirement System (CSRS) and the Federal Employees Retirement System (FERS) including individuals receiving benefits from the Office of Workers' Compensation Programs, former spouses eligible for benefits under the Spouse Equity Act of 1984, and separated employees and former dependents eligible to enroll under the Temporary Continuation of Coverage provisions of the FEHB law (5 U.S.C. 8905a). A different form (OPM 2809) is used by CSRS and FERS annuitants whose health benefit enrollments are administered by OPM's Retirement Operations.

Analysis

Agency: Federal Employee Insurance Operations, Office of Personnel Management.

Title: Health Benefits Election Form.

OMB Number: 3206–0160.

Frequency: On Occasion.

Affected Public: Individuals or Households.

Number of Respondents: 18,000.

Estimated Time per Respondent: 30 minutes.

Total Burden Hours: 9,000.

U.S. Office of Personnel Management.

Beth F. Cobert,

Acting Director. U.S. Office of Personnel Management.

[FR Doc. 2015–27008 Filed 10–22–15; 8:45 am]

BILLING CODE 6325–38–P

POSTAL REGULATORY COMMISSION

[Docket No. MC2016–7; Order No. 2766]

New Postal Product

AGENCY: Postal Regulatory Commission.

ACTION: Notice.

SUMMARY: The Commission is noticing a recent Postal Service filing concerning the Postal Service's request to remove Global Direct Contracts from the competitive products list. This notice informs the public of the filing, invites public comment, and takes other administrative steps.

DATES: *Comments are due:* October 26, 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:

Table of Contents

I. Introduction

In accordance with 39 U.S.C. 3642 and 39 CFR 3020.30 *et seq.,* the Postal Service filed a formal request and associated supporting information to remove Global Direct Contracts from the competitive product list.[1]

To support its Request, the Postal Service filed four attachments as follows:

- Attachment A—a redacted copy of the Governors' Decision No. 11–6 authorizing the removal of the product from the competitive product list, including a redacted management analysis;
- Attachment B—an application for nonpublic treatment of Governors' Decision No. 11–6;
- Attachment C—a Statement of Supporting Justification as required by 39 CFR 3020.32; and
- Attachment D—proposed changes to the Mail Classification Schedule (MCS) competitive product list.

The Postal Service seeks to remove Global Direct Contracts from the competitive product list due to the absence of customer demand for this service. Request at 1. The Postal Service asserts that removal of Global Direct Contracts is an attempt to align its service offerings with current customer needs and preferences. *Id.* at 2.

In addition, in the Statement of Supporting Justification, Giselle E. Valera, Vice President and Managing Director of Global Business, asserts that because the Postal Service is requesting product removal, the product's ability to cover its own costs has no impact on the instant Request. *Id.* Attachment C at 2. Ms. Valera maintains that removal of the product from the competitive product list attempts to ensure that there will be no issue of market dominant products subsidizing competitive products. *Id.*

[1] Request of the United States Postal Service to Remove Global Direct Contracts from the Competitive Product List, October 16, 2015 (Request).

II. Notice of Filings

The Commission establishes Docket No. MC2016–7 to consider the Request pertaining to the removal of Global Direct Contracts from the competitive product list.

Interested persons may submit comments on whether the Postal Service's filings in the captioned docket are consistent with the policies of 39 U.S.C. 3632, 3633, or 3642, 39 CFR part 3010, 39 CFR part 3015, and 39 CFR part 3020, subpart B and subpart E. Comments are due no later than October 26, 2015. The public portions of the filings can be accessed via the Commission's Web site (*http://www.prc.gov*).

The Commission appoints James F. Callow to serve as Public Representative in this docket.

III. Ordering Paragraphs

It is ordered:

1. The Commission establishes Docket No. MC2016–7 to consider the Postal Service's Request.

2. Pursuant to 39 U.S.C. 505, James F. Callow is appointed to serve as an officer of the Commission (Public Representative) to represent the interests of the general public in these proceedings.

3. Comments by interested persons in these proceedings are due no later than October 26, 2015.

4. The Secretary shall arrange for publication of this order in the **Federal Register**.

Ruth Ann Abrams,

Acting Secretary.

[FR Doc. 2015–26925 Filed 10–22–15; 8:45 am]

BILLING CODE 7710–FW–P

POSTAL SERVICE

Removal of Global Direct Contracts From the Competitive Product List

AGENCY: Postal Service.

ACTION: Notice.

SUMMARY: The Postal Service hereby provides notice that it has filed a request with the Postal Regulatory Commission to remove Global Direct Contracts from the competitive product list.

DATES: *Effective date:* October 23, 2015.

FOR FURTHER INFORMATION CONTACT: Keith Nusbaum, 202–268–6687.

SUPPLEMENTARY INFORMATION: On October 16, 2015, the United States Postal Service® filed with the Postal Regulatory Commission a Request of the United States Postal Service to remove Global Direct Contracts from the Competitive Product List, pursuant to 39 U.S.C. 3642. Documents pertinent to this request are available at *http://www.prc.gov,* Docket No. MC2016–7.

Stanley F. Mires,

Attorney, Federal Compliance.

[FR Doc. 2015–26906 Filed 10–22–15; 8:45 am]

BILLING CODE 7710–12–P

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–76188; File No. SR–FINRA–2015–042]

Self-Regulatory Organizations; Financial Industry Regulatory Authority, Inc.; Notice of Filing and Immediate Effectiveness of a Proposed Rule Change Relating to the New Securities Trader Qualification Examination (Series 57)

October 19, 2015.

Pursuant to Section 19(b)(1) of the Securities Exchange Act of 1934 (''Act'' or ''SEA'') [1] and Rule 19b–4 thereunder,[2] notice is hereby given that on October 13, 2015, Financial Industry Regulatory Authority, Inc. (''FINRA'') 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 FINRA. FINRA has designated the proposed rule change as constituting a ''non-controversial'' rule change under paragraph (f)(6) of Rule 19b–4 under the Act,[3] which renders the proposal effective upon receipt of this filing by 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

FINRA is filing the content outline and selection specifications for the new Securities Trader qualification examination (Series 57).[4] FINRA is not proposing any textual changes to the By-Laws, Schedules to the By-Laws or Rules of FINRA.

The Series 57 content outline is attached.[5] The Series 57 selection specifications have been submitted to the Commission under separate cover with a request for confidential treatment pursuant to SEA Rule 24b–2.[6]

The text of the proposed rule change is available on FINRA's Web site at *http://www.finra.org,* at the principal office of FINRA 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, FINRA 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. FINRA 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

Section 15A(g)(3) of the Act [7] authorizes FINRA to prescribe standards of training, experience, and competence for persons associated with FINRA members. In accordance with that provision, FINRA has developed examinations that are designed to establish that persons associated with FINRA members have attained specified levels of competence and knowledge, consistent with applicable registration requirements under FINRA rules.

The Commission recently approved a proposed rule change to amend NASD Rule 1032(f) (Limited Representative—Equity Trader) to replace the Equity Trader registration category and qualification examination (Series 55) with the Securities Trader registration category and qualification examination (Series 57).[8] The rule provides that each associated person of a member who is included within the definition of ''representative'' in NASD Rule 1031 (Registration Requirements) is required to register with FINRA as a Securities

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

[3] 17 CFR 240.19b–4(f)(6).

[4] FINRA also is establishing the Series 57 question bank. FINRA is submitting this filing for immediate effectiveness pursuant to Section 19(b)(3)(A) of the Act and Rule 19b–4(f)(6) thereunder, and is not filing the question bank. *See* Letter to Alden S. Adkins, Senior Vice President and General Counsel, NASD Regulation, from Belinda Blaine, Associate Director, Division of Market Regulation, SEC, dated July 24, 2000. The question bank is available for SEC review.

[5] The Commission notes that the content outline is attached to the filing, not to this Notice.

[6] 17 CFR 240.24b–2.

[7] 15 U.S.C. 78*o*–3(g)(3).

[8] *See* Securities Exchange Act Release No. 75783 (August 28, 2015), 80 FR 53369 (September 3, 2015) (Order Approving File No. SR–FINRA–2015–017) (''Approval Order'').

Trader if, with respect to transactions in equity (including equity options), preferred or convertible debt securities effected otherwise than on a securities exchange, such person is engaged in proprietary trading, the execution of transactions on an agency basis or the direct supervision of such activities.[9] In addition, NASD Rule 1032(f) provides that in order to register as a Securities Trader, an applicant must pass the Series 57 examination. The Series 57 examination will qualify an associated person to function as a Securities Trader. There is no prerequisite registration requirement for Securities Trader registration. An associated person registered as a Securities Trader will not be qualified to function in any other registered capacity, unless he or she is qualified and registered in that other registration category.[10] For instance, a person registered as a Securities Trader will not be able to engage in any retail or institutional sales activities, unless he or she is qualified and registered in the appropriate registration category, such as a General Securities Representative.

In addition, the Commission approved amendments to NASD Rule 1022(a) (General Securities Principal) to establish a Securities Trader Principal registration category and require each associated person of a member who is included within the definition of ''principal'' in NASD Rule 1021 (Registration Requirements) with supervisory responsibility over the securities trading activities described in NASD Rule 1032(f), to qualify and register as a Securities Trader Principal.[11] To qualify for registration as a Securities Trader Principal, an associated person must be registered as a Securities Trader and pass the General Securities Principal qualification examination (Series 24). An associated person registered as a Securities Trader Principal will not be eligible to register as a General Securities Principal unless the person passes the appropriate prerequisite examination for General Securities Principal registration, such as the Series 7 examination. In this regard, NASD Rule 1022(a) provides that a person qualified and registered as a Securities Trader Principal may only have supervisory responsibility over the activities specified in NASD Rule 1032(f), unless the person is separately qualified and registered in another appropriate principal registration category, such as the General Securities Principal registration category.

FINRA is expecting the national securities exchanges to file similar proposed rule changes to replace the Proprietary Trader qualification examination (Series 56) with the Series 57 examination in their respective registration rules relating to securities trading activities. Further, the Series 57 examination will replace the Series 56 examination for those exchange registration categories, such as the Proprietary Trader Principal registration category, where the Series 56 examination is currently an acceptable prerequisite.

FINRA developed the Series 57 examination in consultation with a committee of industry representatives and representatives of several exchanges. The examination is based on the current job functions of a Securities Trader and includes elements of the Series 55 and 56 examinations. The Series 57 content outline covers the laws, rules and regulations relevant to securities trading as well as the functions and associated tasks performed by a Securities Trader.

Series 57 Content Outline

The Series 57 content outline is divided into four major job functions that are performed by a Securities Trader. The following are the four major job functions, denoted Function 1 through 4, with the associated number of questions:

Function 1: Market Overview and Products, 22 questions;

Function 2: Engaging in Professional Conduct and Adhering to Regulatory Requirements, 12 questions;

Function 3: Trading Activities, 79 questions; and

Function 4: Maintaining Books and Records and Trade Reporting, 12 questions.

The number of questions assigned to each major job function reflects the key tasks performed by a Securities Trader.

Each function also includes specific tasks describing activities associated with performing that function. There are three tasks (1.1–1.3) associated with Function 1; two tasks (2.1–2.2) associated with Function 2; three tasks (3.1–3.3) associated with Function 3; and two tasks (4.1–4.2) associated with Function 4.[12] By way of example, one such task, Task 4.2, relates to creating, retaining, and reporting required records of orders and transactions.[13] Further, the content outline lists the knowledge required to perform each function and associated tasks (*e.g.,* in connection with Task 4.2, large trader ID and related reporting and monitoring requirements and order execution/routing information).[14] In addition, where applicable, the content outline lists the laws, rules and regulations a candidate is expected to know to perform each function and associated tasks.[15] These include applicable federal securities laws, as well as FINRA and other self-regulatory organization rules and regulations. FINRA conducted a job analysis study of Securities Traders, which included the use of a survey, in developing each function and associated tasks and the required knowledge set forth in the content outline. The functions and associated tasks reflect the day-to-day activities of a Securities Trader. The Series 57 selection specifications and question bank cover the topics in the content outline.

The content outline also includes sample questions [16] and reference materials.[17] In the preface, the content outline includes, among other things: (1) A table of contents; (2) details regarding the purpose of the examination; (3) eligibility requirements; (4) the application procedures; (5) information regarding the structure of the examination; (6) details regarding the development and maintenance of the content outline and examination; (7) information regarding the administration of the examination; (8) an explanation that the passing score is determined by FINRA based on a number of factors including industry trends, historical exam performance and evaluations of the content difficulty by a committee of industry professionals, using a standard setting procedure, and that a statistical adjustment process known as equating is used in scoring examinations; and (9) an explanation that each candidate will receive a score report at the end of the test session, which will indicate a pass or fail status and include a score profile listing the candidate's performance on each major content area covered on the examination.[18]

The number of questions on the Series 57 examination will be 125 scored

[9] There is an exception from the Securities Trader registration requirement for any associated person of a member whose trading activities are conducted principally on behalf of an investment company that is registered with the SEC pursuant to the Investment Company Act of 1940 and that controls, is controlled by, or is under common control with the member.

[10] *See* NASD Rule 1032(f).

[11] *See* Approval Order, *supra* note 8.

[12] *See* Exhibit 3a, Outline Pages 6–13. The Commission notes that all references to Exhibit 3a refer to Exhibit 3a to the proposed rule change.

[13] *See* Exhibit 3a, Outline Page 13.

[14] *See* Exhibit 3a, Outline Page 13.

[15] *See* Exhibit 3a, Outline Pages 14–36.

[16] *See* Exhibit 3a, Outline Page 37.

[17] *See* Exhibit 3a, Outline Page 38.

[18] *See* Exhibit 3a, Outline Pages 2–5.

multiple-choice questions,[19] and candidates will have three hours and 45 minutes to complete the examination. The passing score will be 70 percent.

Availability of Content Outline

The Series 57 content outline is available on FINRA's Web site, at *http://www.finra.org/industry/qualification-exams*.

FINRA is filing the proposed rule change for immediate effectiveness. FINRA proposes to implement the Series 57 examination on January 4, 2016. FINRA will announce the proposed rule change and the implementation date in a *Regulatory Notice*.

2. Statutory Basis

FINRA believes that the proposed rule change is consistent with the provisions of Section 15A(b)(6) of the Act,[20] which requires, among other things, that FINRA rules must be designed to prevent fraudulent and manipulative acts and practices, to promote just and equitable principles of trade, and, in general, to protect investors and the public interest, and Section 15A(g)(3) of the Act,[21] which authorizes FINRA to prescribe standards of training, experience, and competence for persons associated with FINRA members. FINRA believes that the proposed rule change furthers these purposes by establishing the qualification examination that individuals, including associated persons of FINRA members, must pass to register and function as Securities Traders and Securities Trader Principals. The examination is intended to safeguard the investing public by helping to ensure that individuals registering as Securities Traders, as well as those responsible for the supervision of securities trading activities, are competent to perform their job functions.

B. Self-Regulatory Organization's Statement on Burden on Competition

FINRA does not believe that the proposed rule change will result in any burden on competition that is not necessary or appropriate in furtherance of the purposes of the Act. The new examination aligns with the functions and associated tasks currently performed by associated persons engaged in securities trading and tests knowledge of the laws, rules, regulations and skills relevant to those functions and associated tasks.

C. Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received From Members, Participants, or Others

Written comments were neither solicited nor received.

III. Date of Effectiveness of the Proposed Rule Change and Timing for Commission Action

Because the foregoing proposed rule change does not: (i) Significantly affect the protection of investors or the public interest; (ii) impose any significant burden on competition; and (iii) become operative for 30 days from the date on which it was filed, or such shorter time as the Commission may designate, it has become effective pursuant to Section 19(b)(3)(A) of the Act[22] and Rule 19b–4(f)(6) thereunder.[23]

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 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–FINRA–2015–042 on the subject line.

Paper Comments

- Send paper comments in triplicate to Robert W. Errett, Deputy Secretary, Securities and Exchange Commission, 100 F Street NE., Washington, DC 20549–1090.

All submissions should refer to File Number SR–FINRA–2015–042. This file number should be included on the subject line if email is used. To help the Commission process and review your comments more efficiently, please use only one method. The Commission will post all comments on the Commission's Internet Web site (*http://www.sec.gov/rules/sro.shtml*). Copies of the submission, all subsequent amendments, all written statements with respect to the proposed rule change that are filed with the Commission, and all written communications relating to the proposed rule change between the Commission and any person, other than those that may be withheld from the public in accordance with the provisions of 5 U.S.C. 552, will be available for Web site viewing and printing in the Commission's Public Reference Room, 100 F Street NE., Washington, DC 20549, on official business days between the hours of 10 a.m. and 3 p.m. Copies of such filing also will be available for inspection and copying at the principal office of FINRA. 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–FINRA–2015–042 and should be submitted on or before November 13, 2015.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[24]

Robert W. Errett,

Deputy Secretary.

[FR Doc. 2015–26912 Filed 10–22–15; 8:45 am]

BILLING CODE 8011–01–P

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–76190; File No. SR–FINRA–2015–039]

Self-Regulatory Organizations; Financial Industry Regulatory Authority, Inc.; Notice of Filing and Immediate Effectiveness of a Proposed Rule Change Relating to the Series 28 Examination Program

October 19, 2015.

Pursuant to Section 19(b)(1) of the Securities Exchange Act of 1934 (''Act'' or ''SEA'')[1] and Rule 19b–4 thereunder,[2] notice is hereby given that

[19] Consistent with FINRA's practice of including ''pretest'' items on qualification examinations, which is designed to ensure that new examination items meet acceptable testing standards prior to use for scoring purposes, the examination includes 10 additional, unidentified pretest items that do not contribute towards the candidate's score. Therefore, the examination actually consists of 135 items, 125 of which are scored. The 10 pretest items are randomly distributed throughout the examination.

[20] 15 U.S.C. 78*o*–3(b)(6).

[21] 15 U.S.C. 78*o*–3(g)(3).

[22] 15 U.S.C. 78s(b)(3)(A).

[23] 17 CFR 240.19b–4(f)(6).

[24] 17 CFR 200.30–3(a)(12).

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

on October 13, 2015, Financial Industry Regulatory Authority, Inc. (''FINRA'') 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 FINRA. FINRA has designated the proposed rule change as ''constituting a stated policy, practice, or interpretation with respect to the meaning, administration, or enforcement of an existing rule'' under Section 19(b)(3)(A)(i) of the Act [3] and Rule 19b–4(f)(1) thereunder,[4] which renders the proposal effective upon receipt of this filing by 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

FINRA is filing revisions to the content outline and selection specifications for the Introducing Broker-Dealer Financial and Operations Principal (Series 28) examination program.[5] The proposed revisions update the material to reflect changes to the laws, rules and regulations covered by the examination and to incorporate the functions and associated tasks currently performed by an Introducing Broker-Dealer Financial and Operations Principal. In addition, FINRA is proposing to make changes to the format of the content outline. FINRA is not proposing any textual changes to the By-Laws, Schedules to the By-Laws or Rules of FINRA.

The revised content outline is attached.[6] The Series 28 selection specifications have been submitted to the Commission under separate cover with a request for confidential treatment pursuant to SEA Rule 24b–2.[7]

The text of the proposed rule change is available on FINRA's Web site at *http://www.finra.org,* at the principal office of FINRA and at the Commission's Public Reference Room.

[3] 15 U.S.C. 78s(b)(3)(A)(i).

[4] 17 CFR 240.19b–4(f)(1).

[5] FINRA also is proposing corresponding revisions to the Series 28 question bank. FINRA is submitting this filing for immediate effectiveness pursuant to Section 19(b)(3)(A) of the Act and Rule 19b–4(f)(1) thereunder, and is not filing the question bank. *See* Letter to Alden S. Adkins, Senior Vice President and General Counsel, NASD Regulation, from Belinda Blaine, Associate Director, Division of Market Regulation, SEC, dated July 24, 2000. The question bank is available for SEC review.

[6] The Commission notes that the content outline is attached to the filing, not to this Notice.

[7] 17 CFR 240.24b–2.

II. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

In its filing with the Commission, FINRA 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. FINRA 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

Section 15A(g)(3) of the Act [8] authorizes FINRA to prescribe standards of training, experience, and competence for persons associated with FINRA members. In accordance with that provision, FINRA has developed examinations that are designed to establish that persons associated with FINRA members have attained specified levels of competence and knowledge, consistent with applicable registration requirements under FINRA rules. FINRA periodically reviews the content of the examinations to determine whether revisions are necessary or appropriate in view of changes pertaining to the subject matter covered by the examinations.

NASD Rule 1022(c)(1) requires that every member that is subject to the requirements of SEA Rule 15c3–1,[9] other than a member operating pursuant to SEA Rule 15c3–1(a)(1)(ii),[10] SEA Rule 15c3–1(a)(2)(i) [11] or SEA Rule 15c3–1(a)(8),[12] shall designate as Introducing Broker-Dealer Financial and Operations Principal [13] those persons associated with it, at least one of whom shall be its chief financial officer, who perform the duties described in paragraph (c)(2) of the rule. The rule provides that each person associated with a member who performs such duties shall be required to register as an Introducing Broker-Dealer Financial and Operations Principal with FINRA and shall pass an appropriate qualification examination before such registration may become effective. Paragraph (b)(2) of the rule provides that the term Introducing Broker-Dealer Financial and Operations Principal shall mean a person associated with a member whose duties include:

- Final approval and responsibilities for the accuracy of financial reports submitted to any duly established securities industry regulatory body;
- final preparation of such reports;
- supervision of individuals who assist in the preparation of such reports;
- supervision of and responsibility for individuals who are involved in the actual maintenance of the member's books and records from which such reports are derived;
- supervision and/or performance of the member's responsibilities under all financial responsibility rules promulgated pursuant to the provisions of the Act;
- overall supervision of and responsibility for the individuals who are involved in the administration and maintenance of the member's back office operations; or
- any other matter involving the financial and operational management of the member.

NASD Rule 1022(c)(3) provides that, except as set forth in NASD Rule 1021(c),[14] a person designated pursuant to the provisions of NASD Rule 1022(c)(1) shall not be required to take the Introducing Broker-Dealer Financial and Operations Principal examination and shall be qualified for registration as such if the person is qualified to be registered or is registered as a Financial and Operations Principal as defined in NASD Rule 1022(b)(2).[15]

NASD Rule 1022(c)(4) provides that a person registered solely as an Introducing Broker-Dealer Financial and Operations Principal shall not be qualified to function in a principal capacity with responsibility over any

[8] 15 U.S.C. 78*o*–3(g)(3).

[9] 17 CFR 240.15c3–1. SEA Rule 15c3–1 is the SEC's net capital rule for brokers and dealers.

[10] 17 CFR 240.15c3–1(a)(1)(ii). SEA Rule 15c3–1(a)(1)(ii) addresses net capital requirements for brokers or dealers that elect not to be subject to the Aggregate Indebtedness Standard of paragraph (a)(1)(i) under Rule 15c3–1.

[11] 17 CFR 240.15c3–1(a)(2)(i). SEA Rule 15c3–1(a)(2)(i) addresses net capital requirements for brokers or dealers that carry customer accounts.

[12] 17 CFR 240.15c3–1(a)(8). SEA Rule 15c3–1(a)(8) addresses net capital requirements for municipal securities brokers' brokers, as defined under the rule.

[13] The term ''Limited Principal—Introducing Broker/Dealer Financial and Operations'' as set forth in NASD Rule 1022(c) is referred to as ''Introducing Broker-Dealer Financial and Operations Principal'' for purposes of this filing. The term ''principal'' is defined in NASD Rule 1021(b) (Definition of Principal).

[14] NASD Rule 1021(c) addresses requirements for examination on lapse of registration.

[15] For purposes of this filing, the term ''Financial and Operations Principal'' is used interchangeably with the term ''Limited Principal—Financial and Operations'' as set forth in NASD Rule 1022(b). Rule 1022(b)(2) sets forth the duties of a Financial and Operations Principal. *See* SR–FINRA–2015–038 (establishing revisions to the content outline and selection specifications for the Financial and Operations Principal (Series 27) examination program).

area of business activity not described in paragraph (c)(2) of the rule. The rule provides that such person shall not be qualified to function in a principal capacity at a member unless the member operates under paragraph (c)(1) of the rule.

In consultation with a committee of industry representatives, FINRA recently undertook a review of the Series 28 examination program. As a result of this review, FINRA is proposing to make revisions to the content outline to reflect changes to the laws, rules and regulations covered by the examination and to incorporate the functions and associated tasks currently performed by an Introducing Broker-Dealer Financial and Operations Principal. FINRA also is proposing to make changes to the format of the content outline.

Current Outline

The current content outline is divided into five sections. The following are the five sections and the number of questions associated with each of the sections, denoted Section 1 through Section 5:

1. Keeping And Preservation of Records and Broker-Dealer Financial Reporting Requirements, 16 questions;
2. Net Capital Requirements, 36 questions;
3. Customer Protection, 10 questions;
4. Uniform Practice Rules, 5 questions; and
5. Other Relevant Regulations and Interpretations, 28 questions.

Each section also includes the applicable laws, rules and regulations associated with that section. The current outline also includes a preface (addressing, among other things, the purpose, administration and scoring of the examination), sample questions and reference materials.

Proposed Revisions

To develop the revised outline, FINRA conducted a job analysis study of Introducing Broker-Dealer Financial and Operations Principals, which included the use of a survey. The study provided detailed information regarding the day-to-day roles, responsibilities and job functions of Introducing Broker-Dealer Financial and Operations Principals. As a result, FINRA is proposing to revise the structure of the outline as described below to include functions and associated tasks that reflect the day-to-day activities of an Introducing Broker-Dealer Financial and Operations Principal.

Specifically, FINRA is proposing to divide the content outline into four major job functions that are performed by an Introducing Broker-Dealer Financial and Operations Principal. The following are the four major job functions, denoted Function 1 through Function 4, with the associated number of questions:

Function 1: Financial Reporting, 16 questions;

Function 2: Operations, General Securities Industry Regulations, and Preservation of Books and Records, 30 questions;

Function 3: Net Capital, 31 questions; and

Function 4: Customer Protection, Funding and Cash Management, 18 questions.

As noted above, each major job function includes an assigned number of questions. FINRA determined the number of questions for each function based on the results of the job analysis study. Thus, compared to the existing outline, the allocation of questions in the revised outline more closely reflects the current day-to-day activities of an Introducing Broker-Dealer Financial and Operations Principal.

Each function also includes specific tasks describing activities associated with performing that function. There are five tasks (1.1–1.5) associated with Function 1; three tasks (2.1–2.3) associated with Function 2; seven tasks (3.1–3.7) associated with Function 3; and three tasks (4.1–4.3) associated with Function 4.[16] By way of example, one such task (Task 2.2) is prepare and preserve financial records to ensure accuracy and completeness of internal financial documents.[17] Further, the outline lists the knowledge required to perform each function and associated tasks (*e.g.,* general ledger and sub-ledgers).[18] In addition, where applicable, the outline lists the laws, rules and regulations a candidate is expected to know to perform each function and associated tasks. These include the applicable FINRA Rules (*e.g.,* FINRA Rule 4160), NASD Rules (*e.g.,* NASD Rule 2340) and SEC rules (*e.g.,* SEA Rule 17a–4).[19]

As noted above, FINRA also is proposing to revise the content outline to reflect changes to the laws, rules and regulations covered by the examination. Among other revisions, FINRA is proposing to revise the content outline to reflect the adoption of rules in the consolidated FINRA rulebook (*e.g.,* NASD Rule 2430 (Charges for Services Performed) and NASD Rule 3110 (Books and Records) were adopted as FINRA Rule 2122 (Charges for Services Performed) and FINRA Rule 4510 Series (Books and Records Requirements), respectively).[20]

FINRA is proposing similar changes to the Series 28 selection specifications and question bank.

Finally, FINRA is proposing to make changes to the format of the content outline, including the preface, sample questions and reference materials. Among other changes, FINRA is proposing to: (1) Add a table of contents;[21] (2) provide more details regarding the purpose of the examination;[22] (3) provide more details on the application procedures;[23] (4) provide more details on the development and maintenance of the content outline and examination;[24] (5) explain that the passing scores are established by FINRA staff, in consultation with a committee of industry representatives, using a standard setting procedure and that the scores are an absolute standard independent of the performance of candidates taking the examination;[25] and (6) note that each candidate will receive a score report at the end of the test session, which will indicate a pass or fail status and include a score profile listing the candidate's performance on each major content area covered on the examination.[26]

The number of questions on the Series 28 examination will remain at 95 multiple-choice questions, and candidates will continue to have 120 minutes to complete the examination. Currently, a score of 70 percent is required to pass the examination. The passing score for the revised Series 28 examination will be 69 percent.

Availability of Content Outlines

The current Series 28 content outline is available on FINRA's Web site, at *http://www.finra.org/industry/qualification-exams.* The revised Series 28 content outline will replace the current content outline on FINRA's Web site.

FINRA is filing the proposed rule change for immediate effectiveness. FINRA proposes to implement the revised Series 28 examination program on December 14, 2015. FINRA will

[16] *See* Exhibit 3a, Outline Pages 6–17. The Commission notes that all references to Exhibit 3a refer to Exhibit 3a to the proposed rule change.

[17] *See* Exhibit 3a, Outline Page 10.

[18] *See* Exhibit 3a, Outline Page 10.

[19] *See* Exhibit 3a, Outline Page 10.

[20] *See* Rule Conversion Chart, available at *http://www.finra.org/Industry/Regulation/FINRARules/p085560.*

[21] *See* Exhibit 3a, Outline Page 2.

[22] *See* Exhibit 3a, Outline Page 3.

[23] *See* Exhibit 3a, Outline Page 3.

[24] *See* Exhibit 3a, Outline Page 4.

[25] *See* Exhibit 3a, Outline Page 5.

[26] *See* Exhibit 3a, Outline Page 5.

announce the proposed rule change and the implementation date in a *Regulatory Notice.*

2. Statutory Basis

FINRA believes that the proposed revisions to the Series 28 examination program are consistent with the provisions of Section 15A(b)(6) of the Act,[27] which requires, among other things, that FINRA rules must be designed to prevent fraudulent and manipulative acts and practices, to promote just and equitable principles of trade, and, in general, to protect investors and the public interest, and Section 15A(g)(3) of the Act,[28] which authorizes FINRA to prescribe standards of training, experience, and competence for persons associated with FINRA members. FINRA believes that the proposed revisions will further these purposes by updating the examination program to reflect changes to the laws, rules and regulations covered by the examination and to incorporate the functions and associated tasks currently performed by an Introducing Broker-Dealer Financial and Operations Principal.

B. Self-Regulatory Organization's Statement on Burden on Competition

FINRA does not believe that the proposed rule change will result in any burden on competition that is not necessary or appropriate in furtherance of the purposes of the Act. The updated examination aligns with the functions and associated tasks currently performed by an Introducing Broker-Dealer Financial and Operations Principal and tests knowledge of the most current laws, rules, regulations and skills relevant to those functions and associated tasks. As such, the proposed revisions would make the examination more efficient and effective.

C. Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received From Members, Participants, or Others

Written comments were neither solicited nor 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) of the Act [29] and paragraph (f)(1) of Rule 19b–4 thereunder.[30] 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 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–FINRA–2015–039 on the subject line.

Paper Comments

• Send paper comments in triplicate to Robert W. Errett, Deputy Secretary, Securities and Exchange Commission, 100 F Street NE., Washington, DC 20549–1090.

All submissions should refer to File Number SR–FINRA–2015–039. This file number should be included on the subject line if email is used. To help the Commission process and review your comments more efficiently, please use only one method. The Commission will post all comments on the Commission's Internet Web site (*http://www.sec.gov/rules/sro.shtml*). Copies of the submission, all subsequent amendments, all written statements with respect to the proposed rule change that are filed with the Commission, and all written communications relating to the proposed rule change between the Commission and any person, other than those that may be withheld from the public in accordance with the provisions of 5 U.S.C. 552, will be available for Web site viewing and printing in the Commission's Public Reference Room, 100 F Street NE., Washington, DC 20549, on official business days between the hours of 10 a.m. and 3 p.m. Copies of such filing also will be available for inspection and copying at the principal office of FINRA. 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–FINRA–2015–039 and should be submitted on or before November 13, 2015.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[31]

Robert W. Errett,

Deputy Secretary.

[FR Doc. 2015–26914 Filed 10–22–15; 8:45 am]

BILLING CODE 8011–01–P

[27] 15 U.S.C. 78*o*–3(b)(6).

[28] 15 U.S.C. 78*o*–3(g)(3).

[29] 15 U.S.C. 78s(b)(3)(A).

[30] 17 CFR 240.19b–4(f)(1).

[31] 17 CFR 200.30–3(a)(12).

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–76186; SR–NYSEArca–2015–02]

Self-Regulatory Organizations; NYSE Arca, Inc.; Notice of Withdrawal of a Proposed Rule Change, as Modified by Amendment No. 1 Thereto, To Amend NYSE Arca Equities Rule 8.600 To Adopt Generic Listing Standards for Managed Fund Shares

October 19, 2015.

On February 17, 2015, NYSE Arca, Inc. (''Exchange'') filed with the Securities and Exchange Commission (''Commission''), pursuant to Section 19(b)(1) of the Securities Exchange Act of 1934 (''Act'') [1] and Rule 19b–4 thereunder,[2] a proposed rule change to amend NYSE Arca Equities Rule 8.600 to adopt generic listing standards for Managed Fund Shares. The proposed rule change was published for comment in the **Federal Register** on March 10, 2015.[3] On April 17, 2015, pursuant to Section 19(b)(2) of the Act,[4] the Commission designated a longer period within which to either approve the proposed rule change, disapprove the proposed rule change, or institute proceedings to determine whether to disapprove the proposed rule change.[5] On June 3, 2015, the Exchange filed Amendment No. 1 to the proposed rule change. On June 11, 2015, the Commission published a notice of filing

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

[3] *See* Securities Exchange Act Release No. 74433 (Mar. 4, 2015), 80 FR 12690.

[4] 15 U.S.C. 78s(b)(2).

[5] *See* Securities Exchange Act Release No. 74755, 80 FR 22762 (Apr. 23, 2015). The Commission determined that it was appropriate to designate a longer period within which to take action on the proposed rule change so that it has sufficient time to consider the proposed rule change and the comments received. Accordingly, the Commission designated June 8, 2015 as the date by which it should approve, disapprove, or institute proceedings to determine whether to disapprove the proposed rule change.

of Amendment No. 1 to the proposed rule change and an order instituting proceedings under Section 19(b)(2)(B) of the Act[6] to determine whether to approve or disapprove the proposed rule change, as modified by Amendment No. 1 thereto.[7] On September 2, 2015, pursuant to Section 19(b)(2) of the Act,[8] the Commission designated a longer period within which to either approve or disapprove the proposed rule change.[9]

On October 13, 2015, the Exchange withdrew the proposed rule change (SR–NYSEArca–2015–02), as modified by Amendment No. 1 thereto.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[10]

Robert W. Errett,

Deputy Secretary.

[FR Doc. 2015–26910 Filed 10–22–15; 8:45 am]

BILLING CODE 8011–01–P

[6] 15 U.S.C. 78s(b)(2)(B).

[7] *See* Securities Exchange Act Release No. 75115 (Jun. 5, 2015), 80 FR 33309.

[8] 15 U.S.C. 78s(b)(2).

[9] *See* Securities Exchange Act Release No. 75813, 80 FR 54330 (Sept. 9, 2015). The Commission designated November 5, 2015 as the date by which the Commission should either approve or disapprove the proposed rule change.

[10] 17 CFR 200.30–3(a)(57).

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–76187; File No. SR–Phlx–2015–80]

Self-Regulatory Organizations; NASDAQ OMX PHLX LLC; Notice of Filing and Immediate Effectiveness of Proposed Rule Change Relating to the Options Floor Broker Management System

October 19, 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 October 7, 2015, NASDAQ OMX PHLX LLC (''Phlx'' or ''Exchange'') filed with the Securities and Exchange Commission (''SEC'' or ''Commission'') the proposed rule change as described in Items I and II, below, which Items have been prepared by the Exchange. The Commission is publishing this notice to solicit comments on the proposed rule change from interested persons.

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

I. Self-Regulatory Organization's Statement of the Terms of the Substance of the Proposed Rule Change

The Exchange proposes to extend the implementation rollout of its enhanced Options Floor Broker Management System, described in more detail below.

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

Currently and until November 3, 2015, the Exchange operates two Floor Broker Management Systems concurrently on the options trading floor: The original Floor Broker Management System operating since 2005 (''FBMS 1''); and the enhanced Floor Broker Management System (''FBMS 2''). The purpose of the proposal is to continue the concurrent operation of FBMS 1 and FBMS 2 for a temporary period ending April 1, 2016 for the reasons stated below; otherwise the Exchange's concurrent operation of FBMS 1 and FBMS 2 would expire November 3, 2015.

FBMS 1 enables Floor Brokers and/or their employees to enter, route, and report transactions stemming from options orders received on the Exchange. FBMS 1 also establishes an electronic audit trail for options orders represented by Floor Brokers on the Exchange. Floor Brokers can also use FBMS 1 to submit orders to Phlx XL, rather than executing the orders in the trading crowd.

FBMS 2 was launched in March 2014. With FBMS 2, all options transactions on the Exchange involving at least one Floor Broker are required to be executed by FBMS 2. In connection with order execution, the Exchange allows FBMS 2 to execute two-sided orders entered by Floor Brokers, including multi-leg orders up to 15 legs, after the Floor Broker has represented the orders in the trading crowd. FBMS 2 also provides Floor Brokers with an enhanced functionality called the complex calculator that calculates and displays a suggested price of each individual component of a multi-leg order, up to 15 legs, submitted on a net debit or credit basis.

The Exchange received approval to implement FBMS 2 as of June 1, 2013,[3] and delayed its implementation until July 2013,[4] until September 2013,[5] until December 2013,[6] and until March 2014.[7] Implementation began on March 7, 2014, with FBMS 2 operating concurrently with FBMS 1. The Exchange intended to retire FBMS 1 after a specified implementation period for FBMS 2. FBMS 2 has been fully rolled out to all Floor Brokers and in all options. Nevertheless, the Exchange delayed the retirement of FBMS 1 until September 1, 2014,[8] November 3, 2014.[9] and, most recently, until November 3, 2015,[10] for reasons relating to the performance of FBMS 2.[11]

The purpose of the delay was originally to repair FBMS 2, and then ultimately the Exchange determined to replace it with a new system. The Exchange contracted with a third-party entity to provide an alternative system (''FBMS 3'') to ultimately replace both FBMS 1 and FBMS 2. The Exchange had intended to implement FBMS 3 by November 3, 2015, but, based on recent estimates from the third-party entity, it will not be ready until March 2016. There were inadvertent delays in the construction of the new system.

During this additional time period, the Exchange will continue to permit Floor Brokers to use both FBMS 1 and FBMS 2 based on their business needs and Floor Brokers can choose whether to use one or both. Both FBMS 1 and FBMS 2 will continue to be available in

[3] Securities Exchange Act Release No. 69471 (April 29, 2013), 78 FR 26096 (May 3, 2013) (SR–Phlx–2013–09).

[4] Securities Exchange Act Release No. 69811 (June 20, 2013), 78 FR 38422 (June 26, 2013) (SR–Phlx–2013–67).

[5] Securities Exchange Act Release No. 70141 (August 8, 2013), 78 FR 49565 (August 14, 2013) (SR–Phlx–2013–83).

[6] Securities Exchange Act Release No. 70629 (October 8, 2013), 78 FR 62852 (October 22, 2013) (SR–Phlx–2013–100).

[7] Securities Exchange Act Release No. 71212 (December 31, 2013), 79 FR 888 (January 7, 2014) (SR–Phlx–2013–129).

[8] Securities Exchange Act Release No. 72135 (May 9, 2014), 79 FR 27966 (May 15, 2014) (SR–Phlx–2014–33).

[9] Securities Exchange Act Release No. 73246 (September 29, 2014), 79 FR 59874 (October 3, 2014) (SR–Phlx–2014–59).

[10] Securities Exchange Act Release No. 73586 (November 13, 2014), 79 FR 68931 (November 19, 2014) (SR–Phlx–2014–71).

[11] The Exchange previously described those performance issues. *Id.*

all options and to all Floor Brokers. For example, a Floor Broker will be able to use FBMS 1 for one order and FBMS 2 for the next order. Accordingly, the Exchange believes that the performance issues with FBMS 2 are less likely and should decrease because the Floor Broker also has the option to use FBMS 1.

2. Statutory Basis

The Exchange believes that its proposal is consistent with Section 6(b) of the Act [12] in general, and furthers the objectives of Section 6(b)(5) of the Act [13] in particular, in that it is designed to promote just and equitable principles of trade and protect investors and the public interest, by providing options Floor Brokers with two different FBMS offerings for order entry and processing. Despite its performance issues, FBMS 2 offers many beneficial features to the Floor Brokers that FBMS 1 does not, such as the complex calculator and increased automation described above, such that the Exchange has determined not to shut down FBMS 2. Having two options for order entry and processing should enable Floor Brokers to operate their businesses and comply with the relevant rules, which is consistent with the protection of investors and the public interest. Continuing to operate both FBMS 1 and FBMS 2 concurrently for a temporary period should also promote just and equitable principles of trade by providing Floor Brokers with the tools to enter and process their orders efficiently. The proposal is not unfairly discriminatory because all Floor Brokers will be able to use both FBMS 1 and FBMS 2.

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 believes that permitting Floor Brokers to use both FBMS 1 and FBMS 2 for an additional period of time while the Exchange receives delivery of a new system should allow it to compete with other floor-based exchanges and help the Exchange's Floor Brokers compete with floor brokers on other options exchanges.

[12] 15 U.S.C. 78f(b).

[13] 15 U.S.C. 78f(b)(5).

C. Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received From Members, Participants, or Others

No comments were solicited. One comment letter was received by the Exchange when the Exchange communicated to the Floor Brokers that the old FBMS would be retired on September 1, 2014.[14] The Comment Letter requested the Commission and Phlx postpone the implementation rollout of the new FBMS from September 1, 2014 to a later date. The Comment Letter alleges that the Floor Brokers did not have proper notice of the end of the implementation period resulting in the termination of the old FBMS. This is not relevant to the proposal at hand. Also, the Comment Letter requests that the new FBMS be postponed to ensure the public outcry system is maintained. The Exchange notes that under FBMS 2, orders will continue to be represented in the trading crowd; order exposure has not been eliminated. The Exchange is merely modernizing how orders are executed and reported to support enhancements to the maintenance of an accurate audit trail.

III. Date of Effectiveness of the Proposed Rule Change and Timing for Commission Action

Because the foregoing proposed rule change does not: (i) Significantly affect the protection of investors or the public interest; (ii) impose any significant burden on competition; and (iii) become operative for 30 days from the date on which it was filed, or such shorter time as the Commission may designate, it has become effective pursuant to Section 19(b)(3)(A)(iii) of the Act [15] and subparagraph (f)(6) of Rule 19b–4 thereunder.[16] A proposed rule change filed under Rule 19b–4(f)(6) normally does not become operative prior to 30 days after the date of filing.[17] Rule 19b–4(f)(6)(iii), however, permits the Commission to designate a shorter time if such action is consistent with the protection of investors and the public interest.[18]

[14] *See* letter from various Phlx Floor Brokers to Mary Jo White, Chairwoman of the Securities and Exchange Commission, dated August 28, 2014 (''Comment Letter'').

[15] 15 U.S.C. 78s(b)(3)(a)(iii).

[16] 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.

[17] 17 CFR 240.19b–4(f)(6)(iii).

[18] *Id.*

The Exchange has requested that the Commission waive the 30-day operative delay. The Exchange has indicated that it has experienced performance issues with FBMS 2 and that it needs additional time to implement the new FBMS 3. Until FBMS 3 becomes available, the Exchange represents that it will continue to operate FBMS 1 and FBMS 2 concurrently and that all Floor Brokers may use either FBMS. Based on the foregoing, the Commission has determined to waive the 30-day operative date so that the proposal may take effect upon filing.[19]

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.[20] If the Commission takes such action, the Commission shall institute proceedings to determine whether the proposed rule should be approved or disapproved.[21]

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–Phlx–2015–80 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–Phlx–2015–80. 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

[19] For purposes only of waiving the 30-day operative delay, the Commission has considered the proposed rule's impact on efficiency, competition, and capital formation. *See* 15 U.S.C. 78c(f).

[20] 15 U.S.C. 78s(b)(3)(C).

[21] *Id.*

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 offices 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–Phlx–2015–80, and should be submitted on or before November 13, 2015.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[22]

Robert W. Errett,

Deputy Secretary.

[FR Doc. 2015–26911 Filed 10–22–15; 8:45 am]

BILLING CODE 8011–01–P

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–76191; File No. SR–PHLX–2015–82]

Self-Regulatory Organizations; NASDAQ OMX PHLX LLC; Notice of Filing and Immediate Effectiveness of Proposed Rule Change Relating to Mini Options

October 19, 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 October 13, 2015, NASDAQ OMX PHLX LLC (''Phlx'' or ''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 Exchange. The Commission is publishing this notice to solicit comments on the proposed rule change from interested persons.

[22] 17 CFR 200.30–3(a)(12).

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

I. Self-Regulatory Organization's Statement of the Terms of Substance of the Proposed Rule Change

The Exchange proposes to amend Commentary .13 to Rule 1012 (Series of Options Open for Trading), entitled ''Mini Options Contracts.'' Specifically, the Exchange proposes to replace the name ''Google Inc.'' with ''Alphabet Inc.''

The Exchange requests that the Commission waive the 30-day operative delay period contained in Exchange Act Rule 19b–4(f)(6)(iii).[3]

The text of the proposed rule change is available on the Exchange's Web site at *http://nasdaqomxphlx.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 to amend Commentary .13 to Rule 1012, regarding Mini Options traded on Phlx, to replace the name ''Google Inc.'' with ''Alphabet Inc.'' Google Inc. (''Google'') recently announced plans to reorganize and create a new public holding company, which will be called Alphabet Inc. (''Alphabet''). As a result of the holding company reorganization, each share of Class A Common Stock (''GOOGL''), which the Exchange has listed as a Mini Option, will automatically convert into an equivalent corresponding share of Alphabet Inc. stock.[4] The symbol ''GOOGL'' remains unchanged.

The Exchange is proposing to make this change to Commentary .13 to Rule 1012 to enable the continued trading of Mini Options on Google's, now Alphabet's Class A shares. The Exchange is proposing to make this change because, on October 5, 2015 Google reorganized and as a result underwent a name change.

[3] 17 CFR 240.19b–4(f)(6)(iii).

[4] The Class C Capital Stock (''GOOG'') which is also impacted by the reorganization are not eligible to be listed as Mini Options on the Exchange, only the Class A Common Stock.

The purpose of this change is to ensure that Commentary .13 to Rule 1012 properly reflects the intention and practice of the Exchange to trade Mini Options on only an exhaustive list of underlying securities outlined in Commentary .13 to Rule 1012. This change is meant to continue the inclusion of Class A shares of Google in the current list of underlying securities that Mini Options can be traded on, while continuing to make clear that class C shares of Google are not part of that list as that class of options has not been approved for Mini Options trading. As a result, the proposed change will help avoid confusion.

2. Statutory Basis

The Exchange believes the proposed rule change is consistent with the Securities Exchange Act of 1934 (the ''Act'') and the rules and regulations thereunder applicable to the Exchange and, in particular, the requirements of Section 6(b) of the Act.[5] Specifically, the Exchange believes the proposed rule change is consistent with the Section 6(b)(5)[6] 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)[7] requirement that the rules of an exchange not be designed to permit unfair discrimination between customers, issuers, brokers, or dealers.

In particular, the proposed rule change to change the name Google to Alphabet to reflect the new ownership structure is consistent with the Act because the proposed change is merely updating the current name associated with the stock symbol GOOGL to allow for continued mini option trading on Google's class A shares. The proposed change will allow for continued benefit

[5] 15 U.S.C. 78f(b).

[6] 15 U.S.C. 78f(b)(5).

[7] *Id.*

to investors by providing them with additional investment alternatives.

B. Self-Regulatory Organization's Statement on Burden on Competition

Phlx 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. The proposed change does not impose any burden on intra-market competition because it applies to all members and member organizations uniformly. There is no burden on inter-market competition because the Exchange is merely attempting to continue to permit trading of GOOGL as a Mini Options, as is the case today. As a result, there will be no substantive changes to the Exchange's operations or its rules.

C. Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received From Members, Participants, or Others

No written comments were either solicited or received.

III. Date of Effectiveness of the Proposed Rule Change and Timing for Commission Action

Because the 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 [8] and Rule 19b–4(f)(6) thereunder.[9]

A proposed rule change filed under Rule 19b–4(f)(6) [10] normally does not become operative for 30 days after the date of filing. However, pursuant to Rule 19b–4(f)(6)(iii) [11] the Commission may designate a shorter time if such action is consistent with the protection of investors and the public interest.

The Exchange has asked the Commission to waive the 30-day operative delay so that the proposal may become operative immediately upon filing. The Commission believes that waiving the 30-day operative delay is consistent with the protection of investors and the public interest, as it will allow the Exchange to continue to list mini options on the Google Class A shares, now Alphabet's Class A shares, following Google's reorganization. For this reason, the Commission designates the proposed rule change to be operative upon filing.[12]

At any time within 60 days of the filing of the proposed rule change, the Commission summarily may temporarily suspend such rule change if it appears to the Commission that such action is necessary or appropriate in the public interest, for the protection of investors, or otherwise in furtherance of the purposes of the Act.

IV. Solicitation of Comments

Interested persons are invited to submit written data, views, and arguments concerning the foregoing, including whether the proposed rule change is consistent with the Act. Comments may be submitted by any of the following methods:

Electronic Comments

• Use the Commission's Internet comment form (*http://www.sec.gov/rules/sro.shtml*); or

• Send an email to *rule-comments@sec.gov.* Please include File Number SR–PHLX–2015–82 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–PHLX–2015–82. 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–PHLX–2015–82, and should be submitted on or before November 13, 2015.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[13]

Robert W. Errett,

Deputy Secretary.

[FR Doc. 2015–26915 Filed 10–22–15; 8:45 am]

BILLING CODE 8011–01–P

---

[8] 15 U.S.C. 78s(b)(3)(A).

[9] 17 CFR 240.19b–4(f)(6). In addition, Rule 19b–4(f)(6)(iii) requires the Exchange to give the Commission written notice of the Exchange's intent to file the proposed rule change, along with a brief description and text of 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 Commission deems this requirement to have been met.

[10] 17 CFR 240.19b–4(f)(6).

[11] 17 CFR 240.19b–4(f)(6)(iii).

[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).

[13] 17 CFR 200.30–3(a)(12).

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–76189; File No. SR–FINRA–2015–038]

Self-Regulatory Organizations; Financial Industry Regulatory Authority, Inc.; Notice of Filing and Immediate Effectiveness of a Proposed Rule Change Relating to the Series 27 Examination Program

October 19, 2015.

Pursuant to Section 19(b)(1) of the Securities Exchange Act of 1934 (''Act'' or ''SEA'') [1] and Rule 19b–4 thereunder,[2] notice is hereby given that on October 13, 2015, Financial Industry Regulatory Authority, Inc. (''FINRA'') 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 FINRA. FINRA has designated the proposed rule change as ''constituting a stated policy, practice, or interpretation with respect to the meaning, administration, or enforcement of an existing rule'' under Section 19(b)(3)(A)(i) of the Act [3] and Rule 19b–4(f)(1) thereunder,[4] which renders the proposal effective upon receipt of this filing by the Commission. The Commission is publishing this notice to solicit comments on the

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

[3] 15 U.S.C. 78s(b)(3)(A)(i).

[4] 17 CFR 240.19b–4(f)(1).

proposed rule change from interested persons.

I. Self-Regulatory Organization's Statement of the Terms of Substance of the Proposed Rule Change

FINRA is filing revisions to the content outline and selection specifications for the Financial and Operations Principal (Series 27) examination program.[5] The proposed revisions update the material to reflect changes to the laws, rules and regulations covered by the examination and to incorporate the functions and associated tasks currently performed by a Financial and Operations Principal. In addition, FINRA is proposing to make changes to the format of the content outline. FINRA is not proposing any textual changes to the By-Laws, Schedules to the By-Laws or Rules of FINRA.

The revised content outline is attached.[6] The Series 27 selection specifications have been submitted to the Commission under separate cover with a request for confidential treatment pursuant to SEA Rule 24b–2.[7]

The text of the proposed rule change is available on FINRA's Web site at *http://www.finra.org,* at the principal office of FINRA 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, FINRA 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. FINRA has prepared summaries, set forth in sections A, B, and C below, of the most significant aspects of such statements.

[5] FINRA also is proposing corresponding revisions to the Series 27 question bank. FINRA is submitting this filing for immediate effectiveness pursuant to Section 19(b)(3)(A) of the Act and Rule 19b–4(f)(1) thereunder, and is not filing the question bank. *See* Letter to Alden S. Adkins, Senior Vice President and General Counsel, NASD Regulation, from Belinda Blaine, Associate Director, Division of Market Regulation, SEC, dated July 24, 2000. The question bank is available for SEC review.

[6] The Commission notes that the content outline is attached to the filing, not to this Notice.

[7] 17 CFR 240.24b–2.

A. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

1. Purpose

Section 15A(g)(3) of the Act[8] authorizes FINRA to prescribe standards of training, experience, and competence for persons associated with FINRA members. In accordance with that provision, FINRA has developed examinations that are designed to establish that persons associated with FINRA members have attained specified levels of competence and knowledge, consistent with applicable registration requirements under FINRA rules. FINRA periodically reviews the content of the examinations to determine whether revisions are necessary or appropriate in view of changes pertaining to the subject matter covered by the examinations.

NASD Rule 1022(b)(1) requires that each member that operates pursuant to the provisions of SEA Rule 15c3–1(a)(1)(ii),[9] SEA Rule 15c3–1(a)(2)(i)[10] or SEA Rule 15c3–1(a)(8)[11] shall designate as Financial and Operations Principal[12] those persons associated with it, at least one of whom shall be its chief financial officer, who perform the duties described in paragraph (b)(2) of the rule. The rule provides that each person associated with a member who performs such duties shall be required to register as a Financial and Operations Principal with FINRA and shall pass an appropriate qualification examination before such registration may become effective. Paragraph (b)(2) of the rule provides that the term Financial and Operations Principal shall mean a person associated with a member whose duties include:

- Final approval and responsibility for the accuracy of financial reports submitted to any duly established securities industry regulatory body;
- final preparation of such reports;
- supervision of individuals who assist in the preparation of such reports;
- supervision of and responsibility for individuals who are involved in the actual maintenance of the member's books and records from which such reports are derived;
- supervision and/or performance of the member's responsibilities under all financial responsibility rules promulgated pursuant to the provisions of the Act;
- overall supervision of and responsibility for the individuals who are involved in the administration and maintenance of the member's back office operations; or
- any other matter involving the financial and operational management of the member.

[8] 15 U.S.C. 78*o*–3(g)(3).

[9] 17 CFR 240.15c3–1(a)(1)(ii). SEA Rule 15c3–1(a)(1)(ii) addresses net capital requirements for brokers or dealers that elect not to be subject to the Aggregate Indebtedness Standard of paragraph (a)(1)(i) under Rule 15c3–1.

[10] 17 CFR 240.15c3–1(a)(2)(i). SEA Rule 15c3–1(a)(2)(i) addresses net capital requirements for brokers or dealers that carry customer accounts.

[11] 17 CFR 240.15c3–1(a)(8). SEA Rule 15c3–1(a)(8) addresses net capital requirements for municipal securities brokers' brokers, as defined under the rule.

[12] The term "Limited Principal—Financial and Operations" as set forth in NASD Rule 1022(b) is referred to as "Financial and Operations Principal" for purposes of this filing. The term "principal" is defined in NASD Rule 1021(b) (Definition of Principal).

NASD Rule 1022(b)(3) provides that a person registered solely as a Financial and Operations Principal shall not be qualified to function in a principal capacity with responsibility over any area of business activity not described in paragraph (b)(2) of the rule.

In consultation with a committee of industry representatives, FINRA recently undertook a review of the Series 27 examination program. As a result of this review, FINRA is proposing to make revisions to the content outline to reflect changes to the laws, rules and regulations covered by the examination and to incorporate the functions and associated tasks currently performed by a Financial and Operations Principal. FINRA also is proposing to make changes to the format of the content outline.

Current Outline

The current content outline is divided into seven sections. The following are the seven sections and the number of questions associated with each of the sections, denoted Section 1 through Section 7:

1. Keeping And Preservation of Records and Broker-Dealer Financial Reporting Requirements, 15 questions;
2. Net Capital Requirements, 44 questions;
3. Customer Protection, 36 questions;
4. Municipal Securities Rulemaking Board—Regulations, 9 questions;
5. Extensions Of Credit In The Securities Industry, 8 questions;
6. Procedural Rules, 12 questions; and
7. Other Relevant Regulation and Interpretations, 21 questions.

Each section also includes the applicable laws, rules and regulations associated with that section. The current outline also includes a preface (addressing, among other things, the purpose, administration and scoring of the examination), sample questions and reference materials.

Proposed Revisions

To develop the revised outline, FINRA conducted a job analysis study of Financial and Operations Principals, which included the use of a survey. The study provided detailed information regarding the day-to-day roles, responsibilities and job functions of Financial and Operations Principals. As a result, FINRA is proposing to revise the structure of the outline as described below to include functions and associated tasks that reflect the day-to-day activities of a Financial and Operations Principal.

Specifically, FINRA is proposing to divide the content outline into five major job functions that are performed by a Financial and Operations Principal. The following are the five major job functions, denoted Function 1 through Function 5, with the associated number of questions:

Function 1: Financial Reporting, 25 questions;

Function 2: Operations, General Securities Industry Regulations, and Preservation of Books and Records, 42 questions;

Function 3: Customer Protection, 24 questions;

Function 4: Net Capital, 41 questions; and

Function 5: Funding and Cash Management, 13 questions.

As noted above, each major job function includes an assigned number of questions. FINRA determined the number of questions for each function based on the results of the job analysis study. Thus, compared to the existing outline, the allocation of questions in the revised outline more closely reflects the current day-to-day activities of a Financial and Operations Principal.

Each function also includes specific tasks describing activities associated with performing that function. There are five tasks (1.1–1.5) associated with Function 1; three tasks (2.1–2.3) associated with Function 2; five tasks (3.1–3.5) associated with Function 3; seven tasks (4.1–4.7) associated with Function 4; and two tasks (5.1–5.2) associated with Function 5.[13] By way of example, one such task (Task 2.2) is to prepare and preserve financial records to ensure accuracy and completeness of internal financial documents.[14] Further, the outline lists the knowledge required to perform each function and associated tasks (*e.g.,* general ledger and sub-ledgers).[15] In addition, where applicable, the outline lists the laws, rules and regulations a candidate is expected to know to perform each function and associated tasks. These include the applicable FINRA Rules (*e.g.,* FINRA Rule 4160), NASD Rules (*e.g.,* NASD Rule 2340) and SEC rules (*e.g.,* SEA Rule 17a–4).[16]

As noted above, FINRA also is proposing to revise the content outline to reflect changes to the laws, rules and regulations covered by the examination. Among other revisions, FINRA is proposing to revise the content outline to reflect the adoption of rules in the consolidated FINRA rulebook (*e.g.,* NASD Rule 2430 (Charges for Services Performed) and NASD Rule 3110 (Books and Records) were adopted as FINRA Rule 2122 (Charges for Services Performed) and FINRA Rule 4510 Series (Books and Records Requirements), respectively).[17] Further, based on the MSRB's elimination of the Financial and Operations Principal requirements in MSRB Rule G–3(d), the revised outline does not include any MSRB rules.[18]

FINRA is proposing similar changes to the Series 27 selection specifications and question bank.

Finally, FINRA is proposing to make changes to the format of the content outline, including the preface, sample questions and reference materials. Among other changes, FINRA is proposing to: (1) Add a table of contents;[19] (2) provide more details regarding the purpose of the examination;[20] (3) provide more details on the application procedures;[21] (4) provide more details on the development and maintenance of the content outline and examination;[22] (5) explain that the passing scores are established by FINRA staff, in consultation with a committee of industry representatives, using a standard setting procedure and that the scores are an absolute standard independent of the performance of candidates taking the examination;[23] and (6) note that each candidate will receive a score report at the end of the test session, which will indicate a pass or fail status and include a score profile listing the candidate's performance on each major content area covered on the examination.[24]

The number of questions on the Series 27 examination will remain at 145 scored multiple-choice questions,[25] and candidates will continue to have 225 minutes to complete the examination. Currently, a score of 70 percent is required to pass the examination. The passing score for the revised Series 27 examination will be 69 percent.

Availability of Content Outlines

The current Series 27 content outline is available on FINRA's Web site, at *http://www.finra.org/industry/qualification-exams*. The revised Series 27 content outline will replace the current content outline on FINRA's Web site.

FINRA is filing the proposed rule change for immediate effectiveness. FINRA proposes to implement the revised Series 27 examination program on December 14, 2015. FINRA will announce the proposed rule change and the implementation date in a *Regulatory Notice*.

2. Statutory Basis

FINRA believes that the proposed revisions to the Series 27 examination program are consistent with the provisions of Section 15A(b)(6) of the Act,[26] which requires, among other things, that FINRA rules must be designed to prevent fraudulent and manipulative acts and practices, to promote just and equitable principles of trade, and, in general, to protect investors and the public interest, and Section 15A(g)(3) of the Act,[27] which authorizes FINRA to prescribe standards of training, experience, and competence for persons associated with FINRA members. FINRA believes that the proposed revisions will further these purposes by updating the examination program to reflect changes to the laws, rules and regulations covered by the examination and to incorporate the functions and associated tasks currently performed by a Financial and Operations Principal.

[13] *See* Exhibit 3a, Outline Pages 6–20. The Commission notes that all references to Exhibit 3a refer to Exhibit 3a to the proposed rule change.

[14] *See* Exhibit 3a, Outline Page 10.

[15] *See* Exhibit 3a, Outline Page 10.

[16] *See* Exhibit 3a, Outline Page 10.

[17] *See* Rule Conversion Chart, available at *http://www.finra.org/Industry/Regulation/FINRARules/p085560*.

[18] *See* Securities Exchange Act Release No. 72743 (August 1, 2014), 79 FR 46290 (August 7, 2014) (Order Approving File No. SR–MSRB–2014–04).

[19] *See* Exhibit 3a, Outline Page 2.

[20] *See* Exhibit 3a, Outline Page 3.

[21] *See* Exhibit 3a, Outline Page 3.

[22] *See* Exhibit 3a, Outline Page 4.

[23] *See* Exhibit 3a, Outline Page 5.

[24] *See* Exhibit 3a, Outline Page 5.

[25] Consistent with FINRA's practice of including ''pre-test'' questions on certain qualification examinations, which is designed to ensure that new examination questions meet acceptable testing standards prior to use for scoring purposes, the examination includes ten additional, unidentified pre-test questions that do not contribute towards the candidate's score. Therefore, the examination actually consists of 155 questions, 145 of which are scored. The ten pre-test questions are randomly distributed throughout the examination.

[26] 15 U.S.C. 78*o*–3(b)(6).

[27] 15 U.S.C. 78*o*–3(g)(3).

B. Self-Regulatory Organization's Statement on Burden on Competition

FINRA does not believe that the proposed rule change will result in any burden on competition that is not necessary or appropriate in furtherance of the purposes of the Act. The updated examination aligns with the functions and associated tasks currently performed by a Financial and Operations Principal and tests knowledge of the most current laws, rules, regulations and skills relevant to those functions and associated tasks. As such, the proposed revisions would make the examination more efficient and effective.

C. Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received From Members, Participants, or Others

Written comments were neither solicited nor 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) of the Act [28] and paragraph (f)(1) of Rule 19b–4 thereunder.[29] 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 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–FINRA–2015–038 on the subject line.

Paper Comments

- Send paper comments in triplicate to Robert W. Errett, Deputy Secretary, Securities and Exchange Commission, 100 F Street NE., Washington, DC 20549–1090.

All submissions should refer to File Number SR–FINRA–2015–038. This file number should be included on the subject line if email is used. To help the Commission process and review your comments more efficiently, please use only one method. The Commission will post all comments on the Commission's Internet Web site (*http://www.sec.gov/rules/sro.shtml*). Copies of the submission, all subsequent amendments, all written statements with respect to the proposed rule change that are filed with the Commission, and all written communications relating to the proposed rule change between the Commission and any person, other than those that may be withheld from the public in accordance with the provisions of 5 U.S.C. 552, will be available for Web site viewing and printing in the Commission's Public Reference Room, 100 F Street NE., Washington, DC 20549, on official business days between the hours of 10 a.m. and 3 p.m. Copies of such filing also will be available for inspection and copying at the principal office of FINRA. 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–FINRA–2015–038 and should be submitted on or before November 13, 2015.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[30]

Robert W. Errett,

Deputy Secretary.

[FR Doc. 2015–26913 Filed 10–22–15; 8:45 am]

BILLING CODE 8011–01–P

[28] 15 U.S.C. 78s(b)(3)(A).

[29] 17 CFR 240.19b–4(f)(1).

[30] 17 CFR 200.30–3(a)(12).

SECURITIES AND EXCHANGE COMMISSION

Investment Company Act Release No. 31870; File No. 812–14536 Advisors Asset Management, Inc. and AAM ETF Trust; Notice of Application

October 19, 2015.

AGENCY: Securities and Exchange Commission (''Commission'').

ACTION: Notice of an application for an order under section 12(d)(1)(J) of the Investment Company Act of 1940 (the ''Act'') for an exemption from sections 12(d)(1)(A), (B), and (C) of the Act and under sections 6(c) and 17(b) of the Act for an exemption from sections 17(a)(1) and (2) of the Act. The requested order would permit certain registered open-end investment companies to acquire shares of certain registered open-end investment companies, registered closed-end investment companies, business development companies, as defined in section 2(a)(48) of the Act, and unit investment trusts (collectively, ''Underlying Funds'') that are within and outside the same group of investment companies as the acquiring investment companies, in excess of the limits in section 12(d)(1) of the Act.

APPLICANTS: AAM ETF Trust, a Massachusetts business trust that intends to register under the Act as an open-end management investment company with multiple series and Advisors Asset Management, Inc., a Delaware Corporation registered as an investment adviser under the Investment Advisers Act of 1940.

FILING DATES: The application was filed on August 20, 2015.

HEARING OR NOTIFICATION OF HEARING: An order granting the requested relief will be issued unless the Commission orders a hearing. Interested persons may request a hearing by writing to the Commission's Secretary and serving applicants with a copy of the request, personally or by mail. Hearing requests should be received by the Commission by 5:30 p.m. on November 13, 2015 and should be accompanied by proof of service on the applicants, in the form of an affidavit, or, for lawyers, a certificate of service. Pursuant to Rule 0–5 under the Act, hearing requests should state the nature of the writer's interest, any facts bearing upon the desirability of a hearing on the matter, the reason for the request, and the issues contested. Persons who wish to be notified of a hearing may request notification by writing to the Commission's Secretary.

ADDRESSES: Brent J. Fields, Secretary, U.S. Securities and Exchange Commission, 100 F Street NE., Washington, DC 20549–1090. Applicants: c/o Scott I. Colyer, Advisors Asset Management, Inc., 18925 Base Camp Road, Suite 203, Monument, Colorado 80132.

FOR FURTHER INFORMATION CONTACT: Barbara T. Heussler, Senior Counsel, at (202) 551–6990, or Mary Kay Frech, Branch Chief, at (202) 551–6821 (Division of Investment Management, Chief Counsel's Office).

SUPPLEMENTARY INFORMATION: The following is a summary of the application. The complete application may be obtained via the Commission's Web site by searching for the file number, or for an applicant using the Company name box, at *http://www.sec.gov/search/search.htm,* or by calling (202) 551–8090.

Summary of the Application

1. Applicants request an order to permit (a) a Fund [1] (each a ''Fund of Funds'') to acquire shares of Underlying Funds [2] in excess of the limits in sections 12(d)(1)(A) and (C) of the Act and (b) the Underlying Funds that are registered open-end investment companies or series thereof, their principal underwriters and any broker or dealer registered under the Securities Exchange Act of 1934 to sell shares of the Underlying Fund to the Fund of Funds in excess of the limits in section 12(d)(1)(B) of the Act.[3] Applicants also request an order of exemption under sections 6(c) and 17(b) of the Act from the prohibition on certain affiliated transactions in section 17(a) of the Act to the extent necessary to permit the Underlying Funds to sell their shares to, and redeem their shares from, the Funds of Funds.[4] Applicants state that such transactions will be consistent with the policies of each Fund of Funds and each Underlying Fund and with the general purposes of the Act and will be based on the net asset values of the Underlying Funds.

2. Applicants agree that any order granting the requested relief will be subject to the terms and conditions stated in the application. Such terms and conditions are designed to, among other things, help prevent any potential (i) undue influence over an Underlying Fund that is not in the same ''group of investment companies'' as the Fund of Funds through control or voting power, or in connection with certain services, transactions, and underwritings, (ii) excessive layering of fees, and (iii) overly complex fund structures, which are the concerns underlying the limits in sections 12(d)(1)(A), (B), and (C) of the Act.

3. Section 12(d)(1)(J) of the Act provides that the Commission may exempt any person, security, or transaction, or any class or classes of persons, securities, or transactions, from any provision of section 12(d)(1) if the exemption is consistent with the public interest and the protection of investors. Section 17(b) of the Act authorizes the Commission to grant an order permitting a transaction otherwise prohibited by section 17(a) if it finds that (a) the terms of the proposed transaction are fair and reasonable and do not involve overreaching on the part of any person concerned; (b) the proposed transaction is consistent with the policies of each registered investment company involved; and (c) the proposed transaction is consistent with the general purposes of the Act. Section 6(c) of the Act permits the Commission to exempt any persons or transactions from any provision of the Act if such exemption is necessary or appropriate in the public interest and consistent with the protection of investors and the purposes fairly intended by the policy and provisions of the Act.

For the Commission, by the Division of Investment Management, pursuant to delegated authority.

Robert W. Errett,

Deputy Secretary.

[FR Doc. 2015–26917 Filed 10–22–15; 8:45 am]

BILLING CODE 8011–01–P

[1] Applicants request that the order apply to each existing and future series of AAM ETF Trust and to each existing and future registered open-end investment company or series thereof that is advised by Advisors Asset Management, Inc. or its successor or by any entity controlling, controlled by or under common control with Advisors Asset Management, Inc. or its successor and is part of the same ''group of investment companies'' as AAM ETF Trust (each, a ''Fund''). For purposes of the requested order, ''successor'' is limited to an entity that results from a reorganization into another jurisdiction or a change in the type of business organization. For purposes of the request for relief, the term ''group of investment companies'' means any two or more investment companies, including closed-end investment companies and business development companies, that hold themselves out to investors as related companies for purposes of investment and investor services.

[2] Certain of the Underlying Funds have obtained exemptions from the Commission necessary to permit their shares to be listed and traded on a national securities exchange at negotiated prices and, accordingly, to operate as an exchange-traded fund (''ETF'').

[3] Applicants represent that a Funds of Funds will not invest in reliance on the order in business development companies or closed-end investment companies that are not listed and traded on a national securities exchange.

[4] A Fund of Funds generally would purchase and sell shares of an Underlying Fund that operates as an ETF through secondary market transactions rather than through principal transactions with the Underlying Fund. Applicants nevertheless request relief from section 17(a) to permit a Fund of Funds to purchase or redeem shares from the ETF. A Fund of Funds will purchase and sell shares of an Underlying Fund that is a closed-end fund through secondary market transactions at market prices rather than through principal transactions with the closed-end fund. Accordingly, applicants are not requesting section 17(a) relief with respect to transactions in shares of closed-end funds (including business development companies).

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–76192; File No. SR–CBOE–2015–091]

Self-Regulatory Organizations; Chicago Board Options Exchange, Incorporated; Notice of Filing and Immediate Effectiveness of a Proposed Rule Change To Amend the Fees Schedule

October 19, 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 October 9, 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, 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

In March 2015, the Exchange launched Extended Trading Hours (''ETH'') for options on the S&P 500

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

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 recently designated p.m.-settled options on the Standard & Poor's 500 Stock Index (''SPXpm'') to be eligible for trading during ETH. The Exchange commenced trading of SPXpm during ETH on October 1, 2015. As such, the Exchange proposes to establish fees for the trading of SPXpm during ETH (all fees referenced herein are per-contract unless otherwise stated).[5] First, the Exchange proposes to amend Footnote 37, which provides general information regarding the two trading sessions and indicates which products will be available in ETH, to include trading of SPXpm.

Transaction Fees

The Exchange proposes to assess the same fees for SPXpm in the ETH session as are assessed for SPXpm in the Regular Trading Hours session (''RTH'').[6] As in RTH, the Proprietary Index Options Rate Table will apply during ETH. Transaction fees for SPXpm options will be as follows (all listed rates are per contract):

Customer (Premium > or = $1)	$0.44
Customer (Premium < $1)	0.35
Clearing Trading Permit Holder Proprietary	0.25
CBOE Market-Maker/LMM	0.20
Joint Back-Office, Broker-Dealer, Non-Trading Permit Holder Market-Maker	0.40
Professional/Voluntary Professional	0.40

Additionally, the Exchange notes that SPXpm transactions executed via AIM during ETH will be assessed AIM Agency/Primary and AIM Contra fees based on an order's origin code (which is currently the case during RTH as well).

Surcharges

The Exchange also proposes to apply in ETH, like RTH, an Index License Surcharge Fee of $0.13 per contract for SPXpm options for all non-customer orders. The surcharges are assessed to help the Exchange recoup license fees the Exchange pays to index licensors for the right to list S&P 500 Index-based products for trading.

LMM Rebate

CBOE Rule 6.1A (Extended Trading Hours) provides that the Exchange may approve one or more Market-Makers to act as Lead Market-Makers (''LMMs'') in each class during ETH in accordance with Rule 8.15A for terms of at least one month.[7] However, to the extent the Exchange approves Market-Makers to act as LMMs during ETH, subparagraph (e)(iii)(B) of Rule 6.1A provides that LMMs must comply with the continuous quoting obligation and other obligations of Market-Makers described in subparagraph (ii) of Rule 6.1A,[8] but not the obligations set forth in Rule 8.15A [9] during ETH for their allocated classes. It further provides that LMMs do not receive a participation entitlement as set forth in Rules 6.45B and 8.15B during ETH. Rather, pursuant to subparagraph (e)(iii)(C) of Rule 6.1A, if an LMM (1) provides continuous electronic quotes in at least the lesser of 99% of the non-adjusted series or 100% of the non-adjusted series minus one call-put pair in an ETH allocated class (excluding intra-day add-on series on the day during which such series are added for trading) during ETH in a given month and (2) ensures an opening of the same percentage of series by 2:05 a.m. for at least 90% of the trading days during ETH in a given month, the LMM will receive a rebate for that month in an amount to be set forth in the Fees Schedule.[10] Specifically, for TPHs acting as LMMs in SPXpm options during ETH, the Exchange proposes to provide in the Fees Schedule (new Footnote 39) that if a LMM meets the heightened standard described above, the LMM will receive a rebate of $1,000 per month. The Exchange believes it is more fitting to implement an incentive program with a rebate during ETH, rather than the obligation/benefit structure that currently exists during RTH. LMMs will not be obligated to satisfy heightened continuous quoting and opening quoting standards during ETH. Instead, LMMs must satisfy a heightened standard to receive a rebate, which the Exchange believes will encourage LMMs to provide liquidity during ETH. Additionally, the Exchange notes that LMMs may have to undertake other expenses to be able to quote at the

[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] The Exchange initially filed the proposed fee changes on October 1, 2015 (SR–CBOE–2015–083). On October 9, 2015, the Exchange withdrew that filing and submitted this filing.

[6] Rule 1.1(qqq) defines ''Regular Trading Hours'' as the hours during which transactions in options may be made on the Exchange as set forth in Rule 6.1 (which hours are from 8:30 a.m. to either. 3:00 p.m. or 3:15 p.m. Chicago time).

[7] *See* CBOE Rule 6.1A(e)(iii)(A).

[8] Rule 6.1A(e)(ii) provides that notwithstanding the 20% contract volume requirement in Rule 8.7(d)(ii), Market-Makers with appointments during Extended Trading Hours must comply with the quoting obligations set forth in Rule 8.7(d)(ii) (except during ETH the Exchange may determine to have no bid/ask differential requirements as set forth in subparagraph (A) and there will be no open outcry quoting obligation as set forth in subparagraph (C)) and all other obligations set forth in Rule 8.7 during that trading session. Additionally, notwithstanding the 90-day and next calendar quarter delay requirements in Rule 8.7(d), a Market-Maker with an ETH appointment in a class must immediately comply with the quoting obligations in Rule 8.7(d)(ii) during ETH.

[9] Rule 8.15A (and Rule 1.1(ccc)) requires LMMs to provide continuous electronic quotes in at least the lesser of 99% of the non-adjusted series or 100% of the non-adjusted series minus one call-put pair within their appointed classes, with the term call-put pair referring to one call and one put that cover the same underlying instrument and have the same expiration date and exercise price, for 90% of the time.

[10] Notwithstanding Rule 1.1(ccc), for purposes of subparagraph (C) of Rule 6.1A, an LMM is deemed to have provided ''continuous electronic quotes'' if the LMM provides electronic two-sided quotes for 90% of the time during Extended Trading Hours in a given month. If a technical failure or limitation of a system of the Exchange prevents the LMM from maintaining, or prevents the LMM from communicating to the Exchange, timely and accurate electronic quotes in a class, the duration of such failure shall not be considered in determining whether the LMM has satisfied the 90% quoting standard with respect to that option class. The Exchange may consider other exceptions to this quoting standard based on demonstrated legal or regulatory requirements or other mitigating circumstances.

heightened standard during ETH such as purchase additional bandwidth.

The Exchange also proposes to make a corollary change to Footnote 38. The Exchange notes that currently, for SPX and VIX options, LLMs [sic] are subject to a different rebate program.[11] As such, the Exchange proposes to clarify that such rebate program is for TPHs acting as a LMM during ETH for SPX and VIX options only.

The Exchange lastly notes that fees, rebates and programs that excluded SPXpm, during RTH will also not apply in ETH.[12]

2. Statutory Basis

The Exchange believes the proposed rule change is consistent with the Securities Exchange Act of 1934 (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 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 proposed transaction fee amounts for SPXpm orders during the ETH session are reasonable, equitable and not unfairly discriminatory because they are the same as the amounts of corresponding fees for SPXpm orders during the RTH session. The Exchange notes that the fee amounts for each separate type of market participant will be assessed equally for each product to all such market participants (*i.e.* all Broker-Dealer orders will be assessed the same amount, all Joint Back-Office orders will be assessed the same amount, etc).

Assessing the Index License Surcharge Fee of $0.13 per contract to SPXpm during ETH is reasonable because the amount is the same as the amount of the corresponding surcharge for SPXpm orders during RTH. The surcharge fee is equitable and not unfairly discriminatory because it will be assessed to all market participants to whom the SPXpm will apply in both RTH and ETH.

The Exchange believes it is reasonable, equitable and not unfairly discriminatory to offer LMMs in SPXpm during ETH that meet a certain heightened quoting standard (described above) a rebate of $1,000 per month given added costs that a LMM may undertake (*e.g.,* purchase of an additional bandwidth) and because it will encourage LMMs in SPXpm to provide increased liquidity. More specifically, the Exchange believes the amount of the proposed rebate is reasonable because it takes into consideration certain additional costs an LMM may incur and the Exchange believes the proposed amount is such that it will incentivize LMMs to meet the heighted quoting standard. Additionally, if a LMM does not satisfy the heightened quoting standard, then it will not receive the proposed rebate. The Exchange believes it is equitable and not unfairly discriminatory to only offer the rebate to LMMs because it benefits all market participants in ETH to encourage LMMs to satisfy the heightened quoting standards, which may increase liquidity during those hours and provide more trading opportunities and tighter spreads. The Exchange also believes it is more fitting, as well as equitable and not unfairly discriminatory to implement an incentive program with a rebate during ETH, rather than the obligation/benefit structure that exists during RTH. Particularly, the Exchange notes that creating an incentive program in which LMMs must satisfy a heightened standard to receive the rebate, encourages LMMs to provide significant liquidity during ETH, which is important as the Exchange expects lower trading liquidity and trading levels during ETH and thus fewer opportunities for an LMM to receive a participation entitlement (as they currently do during RTH). Therefore, a rebate is more appropriate than imposing an obligation to receive a participation entitlement. The Exchange notes that offering a rebate during ETH is merely a different type of financial benefit that may be given to LMMs during ETH if it achieves a heightened quoting level. The Exchange believes it is equitable and not unfairly discriminatory to provide a lesser rebate for LMMs appointed in SPXpm options as compared to LMMs for SPX and VIX options because the Exchange expects lower trading volume in SPXpm options during ETH as compared to volume for SPX and VIX. Therefore, it would not be economically viable for the Exchange to offer the same amount of rebate to LMMs in SPXpm as is offered to LMMs for SPX and VIX.

Finally, not applying in ETH fees, rebates and programs that exclude SPXpm during RTH is reasonable because these fees, rebates and programs will not apply to all TPHs and will be consistent across sessions.

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. The Exchange does not believe that the proposed rule change will impose any burden on intramarket competition that is not necessary or appropriate in furtherance of the purposes of the Act because, while different fees and rebates are assessed to different market participants in some circumstances, these different market participants have different obligations and different circumstances. For example, Clearing TPHs have clearing obligations that other market participants do not have. Market-Makers have quoting obligations that other market participants do not have. There is a history in the options markets of providing preferential treatment to Customers, as they often do not have as sophisticated trading operations and systems as other market participants, which often makes other market participants prefer to trade with Customers. Further, the proposed fees, rebates and programs for ETH are intended to encourage market participants to bring liquidity to the Exchange during ETH (which benefits all market participants), while still covering Exchange costs (including those associated with the upgrading and maintenance of Exchange systems).

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 SPXpm is a proprietary product that will only be traded on CBOE. To the extent that the proposed changes

[11] *See* CBOE Fees Schedule, Footnote 38. If a LMM meets the heightened quoting standard, the LMM will receive a pro-rata share of an LMM compensation pool totaling an amount of $25,000 per month, per LMM, per class for SPX and VIX.

[12] *See e.g.,* Exchange Fees Schedule, Liquidity Provider Sliding Scale, Marketing Fee, Clearing Trading Permit Holder Fee Cap, and Volume Incentive Program (''VIP'').

[13] 15 U.S.C. 78f(b).

[14] 15 U.S.C. 78f(b)(5).

[15] 15 U.S.C. 78f(b)(4).

make CBOE a more attractive marketplace for market participants at other exchanges, such market participants are welcome to become CBOE market participants.

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 [16] and paragraph (f) of Rule 19b–4 [17] 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. 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–2015–091 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–2015–091. 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 offices 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–2015–091, and should be submitted on or before November 13, 2015.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[18]

Robert W. Errett,

Deputy Secretary.

[FR Doc. 2015–26916 Filed 10–22–15; 8:45 am]

BILLING CODE 8011–01–P

[16] 15 U.S.C. 78s(b)(3)(A).

[17] 17 CFR 240.19b–4(f).

[18] 17 CFR 200.30–3(a)(12).

SMALL BUSINESS ADMINISTRATION

Data Collection Available for Public Comments

ACTION: 60-day notice and request for comments.

SUMMARY: The Small Business Administration (SBA) intends to request approval, from the Office of Management and Budget (OMB) for the collection of information described below. The Paperwork Reduction Act (PRA) of 1995, 44 U.S.C Chapter 35 requires federal agencies to publish a notice in the **Federal Register** concerning each proposed collection of information before submission to OMB, and to allow 60 days for public comment in response to the notice. This notice complies with that requirement.

DATES: Submit comments on or before December 22, 2015.

ADDRESSES: Send all comments to Gina Beyer, Program Analyst, Office of Disaster Assistance, Small Business Administration, 409 3rd Street, 6th Floor, Washington, DC 20416.

FOR FURTHER INFORMATION CONTACT: Gina Beyer, Program Analyst, Disaster Assistance, *gina.beyer@sba.gov* 202–205–6458, or Curtis B. Rich, Management Analyst, 202–205–7030, *curtis.rich@sba.gov;*

SUPPLEMENTARY INFORMATION: A team of Quality Assurance staff at the Disaster Assistance Center (DASC) will conduct a brief telephone survey of customers to determine their satisfaction with the services received from the (DASC) and the Field Operations Centers. The result will help the Agency to improve where necessary, the delivery of critical financial assistance to disaster victims.

Solicitation of Public Comments

SBA is requesting comments on (a) Whether the collection of information is necessary for the agency to properly perform its functions; (b) whether the burden estimates are accurate; (c) whether there are ways to minimize the burden, including through the use of automated techniques or other forms of information technology; and (d) whether there are ways to enhance the quality, utility, and clarity of the information.

Summary of Information Collection

Title: Disaster Assistance Customer Satisfaction Survey.

Description of Respondents: Disaster Customers satisfaction with service received.

Form Number: SBA Form 2313FOC, 2313CSC.

Total Estimated Annual Responses: 24,284.

Total Estimated Annual Hour Burden: 199.

Curtis B. Rich,

Management Analyst.

[FR Doc. 2015–26895 Filed 10–22–15; 8:45 am]

BILLING CODE 8025–01–P

SMALL BUSINESS ADMINISTRATION

Data Collection Available for Public Comments

ACTION: 60-day notice and request for comments.

SUMMARY: The Small Business Administration (SBA) intends to request approval, from the Office of Management and Budget (OMB) for the collection of information described below. The Paperwork Reduction Act (PRA) of 1995, 44 U.S.C Chapter 35 requires federal agencies to publish a notice in the **Federal Register** concerning each proposed collection of

information before submission to OMB, and to allow 60 days for public comment in response to the notice. This notice complies with that requirement.

DATES: Submit comments on or before December 22, 2015.

ADDRESSES: Send all comments to Michael Simmons, Attorney Advisor, Office of Capital Access, Small Business Administration, 395 E Street, Patriots Plaza, Washington, DC 20416.

FOR FURTHER INFORMATION CONTACT: Michael Simmons, Attorney Advisor, Office of Capital Access, *Michael.simmons@sba.gov* 202–205–6402, or Curtis B. Rich, Management Analyst, 202–205–7030, *curtis.rich@sba.gov.*

SUPPLEMENTARY INFORMATION: Information collection is needed to ensure that Microloan Program activity meets the statutory goals of assisting mandated target market. The information is used by the reporting participants and the SBA to assist with portfolio management, risk management, loan servicing, oversight and compliance, data management and understanding of short and loan term trends and development of outcome measures.

Solicitation of Public Comments

SBA is requesting comments on (a) whether the collection of information is necessary for the agency to properly perform its functions; (b) whether the burden estimates are accurate; (c) whether there are ways to minimize the burden, including through the use of automated techniques or other forms of information technology; and (d) whether there are ways to enhance the quality, utility, and clarity of the information.

Summary of Information Collection

Title: Microloan Program Electronic Reporting System (MPERS) (MPERsystem).

Description of Respondents: SBA reporting participants in the Microloan Program.

Form Number: N/A.

Total Estimated Annual Responses: 170.

Total Estimated Annual Hour Burden: 3,060.

Curtis B. Rich,

Management Analyst.

[FR Doc. 2015–26896 Filed 10–22–15; 8:45 am]

BILLING CODE 8025–01–P

SMALL BUSINESS ADMINISTRATION

Data Collection Available for Public Comments

ACTION: 60-day notice and request for comments.

SUMMARY: The Small Business Administration (SBA) intends to request approval, from the Office of Management and Budget (OMB) for the collection of information described below. The Paperwork Reduction Act (PRA) of 1995, 44 U.S.C Chapter 35 requires federal agencies to publish a notice in the **Federal Register** concerning each proposed collection of information before submission to OMB, and to allow 60 days for public comment in response to the notice. This notice complies with that requirement.

DATES: Submit comments on or before December 22, 2015.

ADDRESSES: Send all comments to Gina Beyer, Program Analyst, Office of Disaster Assistance, Small Business Administration, 409 3rd Street, 6th Floor, Washington, DC 20416.

FOR FURTHER INFORMATION CONTACT: Gina Beyer, Program Analyst, Disaster Assistance, *gina.beyer@sba.gov* 202–205–6458, or Curtis B. Rich, Management Analyst, 202–205–7030, *curtis.rich@sba.gov;*

SUPPLEMENTARY INFORMATION: Prior to Small Business Administration (SBA) approval of subsequent loan disbursement, disaster loan borrowers are required to submit information to demonstrate that they used loan proceeds for authorized purposes only and to make certain certification regarding current financial condition and previously reported compensation paid in connection with the loan.

Solicitation of Public Comments

SBA is requesting comments on (a) Whether the collection of information is necessary for the agency to properly perform its functions; (b) whether the burden estimates are accurate; (c) whether there are ways to minimize the burden, including through the use of automated techniques or other forms of information technology; and (d) whether there are ways to enhance the quality, utility, and clarity of the information.

Summary of Information Collection

Title: Borrower's Progress Certification.

Description of Respondents: Disaster loan Borrowers.

Form Number: SBA Form 1366.

Total Estimated Annual Responses: 13,850.

Total Estimated Annual Hour Burden: 6,925.

Curtis B. Rich,

Management Analyst.

[FR Doc. 2015–26894 Filed 10–22–15; 8:45 am]

BILLING CODE 8025–01–P

SMALL BUSINESS ADMINISTRATION

Data Collection Available for Public Comments

ACTION: 60 Day Notice and request for comments.

SUMMARY: The Small Business Administration (SBA) intends to request approval, from the Office of Management and Budget (OMB) for the collection of information described below. The Paperwork Reduction Act (PRA) of 1995, 44 U.S.C Chapter 35 requires federal agencies to publish a notice in the **Federal Register** concerning each proposed collection of information before submission to OMB, and to allow 60 days for public comment in response to the notice. This notice complies with that requirement.

DATES: Submit comments on or before December 22, 2015.

ADDRESSES: Send all comments to Louis Cupp, New Markets Policy Analyst, Investment, Small Business Administration, 409 3rd Street SW., 6th Floor, Washington, DC 20416.

FOR FURTHER INFORMATION CONTACT: Louis Cupp, New Market Policy Analyst, 202–619–0511 *louis.cupp@sba.gov* Curtis B. Rich, Management Analyst, 202–205–7030 *curtis.rich@sba.gov.*

SUPPLEMENTARY INFORMATION: Form 857 is used by SBA examiners to obtain information about financing provided by small business investment companies (SBICs). This information, which is collected directly from the financed small business, provides independent confirmation of information reported to SBA by SBICs, as well as additional information not reported by SBICs.

Title: ''Request for Information Concerning Portfolio Financing''.

Description of Respondents: Small business Investment Companies.

Form Number: 857.

Annual Responses: 2,250.

Annual Burden: 2,250.

Curtis Rich,

Management Analyst.

[FR Doc. 2015–26892 Filed 10–22–15; 8:45 am]

BILLING CODE P

SMALL BUSINESS ADMINISTRATION

Data Collection Available for Public Comments

ACTION: 60 Day Notice and request for comments.

SUMMARY: The Small Business Administration (SBA) intends to request approval, from the Office of Management and Budget (OMB) for the collection of information described below. The Paperwork Reduction Act (PRA) of 1995, 44 U.S.C Chapter 35 requires federal agencies to publish a notice in the **Federal Register** concerning each proposed collection of information before submission to OMB, and to allow 60 days for public comment in response to the notice. This notice complies with that requirement.

DATES: Submit comments on or before December 22, 2015.

ADDRESSES: Send all comments to Brenda Washington, Senior Program Analyst, HUBZone, Small Business Administration, 395 E Street SW., Patriot Plaza, Washington, DC 20416.

FOR FURTHER INFORMATION CONTACT: Brenda Washington, Senior Analyst, 202–205–7663 *brenda.washington@sba.gov* Curtis B. Rich, Management Analyst, 202–205–7030 *curtis.rich@sba.gov.*

SUPPLEMENTARY INFORMATION: The collected information is submitted by small business concerns seeking certification as a qualified HUBZone small business. SBA uses the information to verify a concern's eligibility for the HUBZone programs, to complied a database of qualified small business concerns, as well as for the re-certification and examination of certified HUBZone small business concerns. Finally SBA uses the information to prepare reports for the Executive and legislative branches.

Title: ''HUBZone Program Electronic Application, Re-certification and Program Examination''.

Description of Respondents: Small business concerns seeking certification as a qualified HUBZone.

Form Number: N/A.

Annual Responses: 5,230.

Annual Burden: 13,290.

Curtis Rich,

Management Analyst.

[FR Doc. 2015–26893 Filed 10–22–15; 8:45 am]

BILLING CODE P

SMALL BUSINESS ADMINISTRATION

[Disaster Declaration #14503 and #14504]

Washington Disaster #WA–00060

AGENCY: U.S. Small Business Administration.

ACTION: Notice.

SUMMARY: This is a Notice of the Presidential declaration of a major disaster for Public Assistance Only for the State of Washington (FEMA–4242–DR), dated 10/15/2015.

Incident: Severe Windstorm.

Incident Period: 08/29/2015.

Effective Date: 10/15/2015.

Physical Loan Application Deadline Date: 12/14/2015.

Economic Injury (EIDL) Loan Application Deadline Date: 07/15/2016.

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 President's major disaster declaration on 10/15/2015, Private Non-Profit organizations that provide essential services of governmental nature may file disaster loan applications 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: Island; Jefferson; Snohomish.

The Interest Rates are:

	Percent
For Physical Damage:	
Non-Profit Organizations With Credit Available Elsewhere	2.625
Non-Profit Organizations Without Credit Available Elsewhere	2.625
For Economic Injury:	
Non-Profit Organizations Without Credit Available Elsewhere	2.625

The number assigned to this disaster for physical damage is 14503B and for economic injury is 14504B

(Catalog of Federal Domestic Assistance Numbers 59002 and 59008).

James E. Rivera,

Associate Administrator for Disaster Assistance.

[FR Doc. 2015–26903 Filed 10–22–15; 8:45 am]

BILLING CODE 8025–01–P

SMALL BUSINESS ADMINISTRATION

[Disaster Declaration #14501 and #14502]

South Carolina Disaster #SC–00032

AGENCY: U.S. Small Business Administration.

ACTION: Notice.

SUMMARY: This is a Notice of the Presidential declaration of a major disaster for Public Assistance Only for the State of South Carolina (FEMA—4241—DR), dated 10/15/2015.

Incident: Severe Storms and Flooding.

Incident Period: 10/01/2015 and continuing.

Effective Date: 10/15/2015.

Physical Loan Application Deadline Date: 12/14/2015.

Economic Injury (EIDL) Loan Application Deadline Date: 07/14/2016.

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 President's major disaster declaration on 10/15/2015, Private Non-Profit organizations that provide essential services of governmental nature may file disaster loan applications 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: Abbeville, Anderson, Bamberg, Berkeley, Colleton, Darlington, Fairfield, Florence, Georgetown, Kershaw, Laurens, Mccormick, Newberry, Richland, Williamsburg.

The Interest Rates are:

	Percent
For Physical Damage:	
Non-Profit Organizations With Credit Available Elsewhere	2.625
Non-Profit Organizations Without Credit Available Elsewhere	2.625

	Percent
For Economic Injury:	
Non-Profit Organizations Without Credit Available Elsewhere	2.625

The number assigned to this disaster for physical damage is 14501B and for economic injury is 14502B.

(Catalog of Federal Domestic Assistance Numbers 59002 and 59008)

James E. Rivera,

Associate Administrator for Disaster Assistance.

[FR Doc. 2015–26902 Filed 10–22–15; 8:45 am]

BILLING CODE 8025–01–M

OFFICE OF THE UNITED STATES TRADE REPRESENTATIVE

North American Free Trade Agreement; Invitation for Applications for Inclusion on the Chapter 19 Roster

AGENCY: Office of the United States Trade Representative.

ACTION: Invitation for applications.

SUMMARY: Chapter 19 of the North American Free Trade Agreement (''NAFTA'') provides for the establishment of a roster of individuals to serve on binational panels convened to review final determinations in antidumping or countervailing duty (''AD/CVD'') proceedings and amendments to AD/CVD statutes of a NAFTA Party. The United States annually renews its selections for the Chapter 19 roster. Applications are invited from eligible individuals wishing to be included on the roster for the period April 1, 2016, through March 31, 2017.

DATES: Applications should be received no later than November 20, 2015.

ADDRESSES: Applications should be submitted (i) electronically to *www.regulations.gov,* docket number USTR–2015–0017 or (ii) by fax, to Sandy McKinzy at (202) 395–3640.

FOR FURTHER INFORMATION CONTACT: Katherine Wang, Assistant General Counsel, Office of the United States Trade Representative, (202) 395–6214.

SUPPLEMENTARY INFORMATION:

Binational Panel Reviews Under NAFTA Chapter 19

Article 1904 of the NAFTA provides that a party involved in an AD/CVD proceeding may obtain review by a binational panel of a final AD/CVD determination of one NAFTA Party with respect to the products of another NAFTA Party. Binational panels decide whether such AD/CVD determinations are in accordance with the domestic laws of the importing NAFTA Party, and must use the standard of review that would have been applied by a domestic court of the importing NAFTA Party. A panel may uphold the AD/CVD determination, or may remand it to the national administering authority for action not inconsistent with the panel's decision. Panel decisions may be reviewed in specific circumstances by a three-member extraordinary challenge committee, selected from a separate roster composed of fifteen current or former judges.

Article 1903 of the NAFTA provides that a NAFTA Party may refer an amendment to the AD/CVD statutes of another NAFTA Party to a binational panel for a declaratory opinion as to whether the amendment is inconsistent with the General Agreement on Tariffs and Trade (''GATT''), the GATT Antidumping or Subsidies Codes, successor agreements, or the object and purpose of the NAFTA with regard to the establishment of fair and predictable conditions for the liberalization of trade. If the panel finds that the amendment is inconsistent, the two NAFTA Parties shall consult and seek to achieve a mutually satisfactory solution.

Chapter 19 Roster and Composition of Binational Panels

Annex 1901.2 of the NAFTA provides for the maintenance of a roster of at least 75 individuals for service on Chapter 19 binational panels, with each NAFTA Party selecting at least 25 individuals. A separate five-person panel is formed for each review of a final AD/CVD determination or statutory amendment. To form a panel, the two NAFTA Parties involved each appoint two panelists, normally by drawing upon individuals from the roster. If the Parties cannot agree upon the fifth panelist, one of the Parties, decided by lot, selects the fifth panelist from the roster. The majority of individuals on each panel must consist of lawyers in good standing, and the chair of the panel must be a lawyer.

Upon each request for establishment of a panel, roster members from the two involved NAFTA Parties will be requested to complete a disclosure form, which will be used to identify possible conflicts of interest or appearances thereof. The disclosure form requests information regarding financial interests and affiliations, including information regarding the identity of clients of the roster member and, if applicable, clients of the roster member's firm.

Criteria for Eligibility for Inclusion on Chapter 19 Roster

Section 402 of the NAFTA Implementation Act (Pub. L. 103–182, as amended (19 U.S.C. 3432)) (''Section 402'') provides that selections by the United States of individuals for inclusion on the Chapter 19 roster are to be based on the eligibility criteria set out in Annex 1901.2 of the NAFTA, and without regard to political affiliation. Annex 1901.2 provides that Chapter 19 roster members must be citizens of a NAFTA Party, must be of good character and of high standing and repute, and are to be chosen strictly on the basis of their objectivity, reliability, sound judgment, and general familiarity with international trade law. Aside from judges, roster members may not be affiliated with any of the three NAFTA Parties. Section 402 also provides that, to the fullest extent practicable, judges and former judges who meet the eligibility requirements should be selected.

Adherence to the NAFTA Code of Conduct for Binational Panelists

The ''Code of Conduct for Dispute Settlement Procedures Under Chapters 19 and 20'' (*see https://www.nafta-sec-alena.org/Default.aspx?tabid=99&language=en-US*), which was established pursuant to Article 1909 of the NAFTA, provides that current and former Chapter 19 roster members ''shall avoid impropriety and the appearance of impropriety and shall observe high standards of conduct so that the integrity and impartiality of the dispute settlement process is preserved.'' The Code of Conduct also provides that candidates to serve on chapter 19 panels, as well as those who are ultimately selected to serve as panelists, have an obligation to ''disclose any interest, relationship or matter that is likely to affect [their] impartiality or independence, or that might reasonably create an appearance of impropriety or an apprehension of bias.'' Annex 1901.2 of the NAFTA provides that roster members may engage in other business while serving as panelists, subject to the Code of Conduct and provided that such business does not interfere with the performance of the panelist's duties. In particular, Annex 1901.2 states that ''[w]hile acting as a panelist, a panelist may not appear as counsel before another panel.''

Procedures for Selection of Chapter 19 Roster Members

Section 402 establishes procedures for the selection by the Office of the United

States Trade Representative (''USTR'') of the individuals chosen by the United States for inclusion on the Chapter 19 roster. The roster is renewed annually, and applies during the one-year period beginning April 1 of each calendar year.

Under Section 402, an interagency committee chaired by USTR prepares a preliminary list of candidates eligible for inclusion on the Chapter 19 Roster. After consultation with the Senate Committee on Finance and the House Committee on Ways and Means, the U.S. Trade Representative selects the final list of individuals chosen by the United States for inclusion on the Chapter 19 roster.

Remuneration

Roster members selected for service on a Chapter 19 binational panel will be remunerated at the rate of 800 Canadian dollars per day.

Applications

Eligible individuals who wish to be included on the Chapter 19 roster for the period April 1, 2016, through March 31, 2017, are invited to submit applications. Applications may be submitted either by fax to Sandy McKinzy at 202–395–3640 or electronically to *www.regulations.gov,* docket number USTR–2015–0017.

To submit an application via *www.regulations.gov,* enter docket number USTR–2015–0017 on the home page and click ''search.'' The site will provide a search-results page listing all documents associated with this docket. Find a reference to this notice by selecting ''Notice'' under ''Document Type'' on the left side of the search-results page, and click on the link entitled ''Comment Now!.'' (For further information on using the *www.regulations.gov* Web site, please consult the resources provided on the Web site by clicking on the ''How to Use Regulations.gov'' on the bottom of the page.)

The *www.regulations.gov* site provides the option of providing comments by filling in a ''Type Comment'' field or by attaching a document. USTR prefers applications to be provided in an attached document. If a document is attached, please type ''Application for Inclusion on NAFTA Chapter 19 Roster'' in the ''Upload File'' field.

Applications must be typewritten, and should be headed ''Application for Inclusion on NAFTA Chapter 19 Roster.'' Applications should include the following information, and each section of the application should be numbered as indicated:

1. Name of the applicant.
2. Business address, telephone number, fax number, and email address.
3. Citizenship(s).
4. Current employment, including title, description of responsibility, and name and address of employer.
5. Relevant education and professional training.
6. Spanish language fluency, written and spoken.
7. Post-education employment history, including the dates and addresses of each prior position and a summary of responsibilities.
8. Relevant professional affiliations and certifications, including, if any, current bar memberships in good standing.
9. A list and copies of publications, testimony, and speeches, if any, concerning AD/CVD law. Judges or former judges should list relevant judicial decisions. Only one copy of publications, testimony, speeches, and decisions need be submitted.
10. Summary of any current and past employment by, or consulting or other work for, the Governments of the United States, Canada, or Mexico.
11. The names and nationalities of all foreign principals for whom the applicant is currently or has previously been registered pursuant to the Foreign Agents Registration Act, 22 U.S.C. 611 *et seq.,* and the dates of all registration periods.
12. List of proceedings brought under U.S., Canadian, or Mexican AD/CVD law regarding imports of U.S., Canadian, or Mexican products in which the applicant advised or represented (for example, as consultant or attorney) any U.S., Canadian, or Mexican party to such proceeding and, for each such proceeding listed, the name and country of incorporation of such party.
13. A short statement of qualifications and availability for service on Chapter 19 panels, including information relevant to the applicant's familiarity with international trade law and willingness and ability to make time commitments necessary for service on panels.
14. On a separate page, the names, addresses, telephone and fax numbers of three individuals willing to provide information concerning the applicant's qualifications for service, including the applicant's character, reputation, reliability, judgment, and familiarity with international trade law.

Current Roster Members and Prior Applicants

Current members of the Chapter 19 roster who remain interested in inclusion on the Chapter 19 roster only need to indicate that they are reapplying and submit updates (if any) to their applications on file. Current members do not need to resubmit their applications. Individuals who have previously applied but have not been selected must submit new applications to reapply. If an applicant, including a current or former roster member, has previously submitted materials referred to in item 9, such materials need not be resubmitted.

Public Disclosure

Applications normally will not be subject to public disclosure and will not be posted publicly on *www.regulations.gov.* They may be referred to other federal agencies and Congressional Committees in the course of determining eligibility for the roster, and shared with foreign governments and the NAFTA Secretariat in the course of panel selection.

False Statements

Pursuant to section 402(c)(5) of the NAFTA Implementation Act, false statements by applicants regarding their personal or professional qualifications, or financial or other relevant interests that bear on the applicants' suitability for placement on the Chapter 19 roster or for appointment to binational panels, are subject to criminal sanctions under 18 U.S.C. 1001.

Privacy Act

The following statements are made in accordance with the Privacy Act of 1974, as amended (5 U.S.C. 552a). The authority for requesting information to be furnished is section 402 of the NAFTA Implementation Act. Provision of the information requested above is voluntary; however, failure to provide the information will preclude your consideration as a candidate for the NAFTA Chapter 19 roster. This information is maintained in a system of records entitled ''Dispute Settlement Panelists Roster.'' Notice regarding this system of records was published in the **Federal Register** on November 30, 2001. The information provided is needed, and will be used by USTR, other federal government trade policy officials concerned with NAFTA dispute settlement, and officials of the other NAFTA Parties to select well-qualified individuals for inclusion on the Chapter 19 roster and for service on Chapter 19 binational panels.

Juan A. Millán,

Acting Assistant United States Trade Representative for Monitoring and Enforcement.

[FR Doc. 2015–26936 Filed 10–22–15; 8:45 am]

BILLING CODE 3290–F6–P

DEPARTMENT OF TRANSPORTATION

Federal Highway Administration

Buy America Waiver Notification

AGENCY: Federal Highway Administration (FHWA), DOT.

ACTION: Notice.

SUMMARY: This notice provides information regarding FHWA's finding that a Buy America waiver is appropriate for the use of non-domestic stainless steel grooved butterfly valves, grooved couplings, and electrical conduit bodies and fittings for the I–90 project in the State of Washington.

DATES: The effective date of the waiver is October 26, 2015.

FOR FURTHER INFORMATION CONTACT: For questions about this notice, please contact Mr. Gerald Yakowenko, FHWA Office of Program Administration, (202) 366–1562, or via email at *gerald.yakowenko@dot.gov.* For legal questions, please contact Mr. Jomar Maldonado, FHWA Office of the Chief Counsel, (202) 366–1373, or via email at *Jomar.Maldonado@dot.gov.* Office hours for the FHWA are from 8:00 a.m. to 4:30 p.m., E.T., Monday through Friday, except Federal holidays.

SUPPLEMENTARY INFORMATION:

Electronic Access

An electronic copy of this document may be downloaded from the Federal Register's home page at: *http://www.archives.gov* and the Government Printing Office's database at: *http://www.access.gpo.gov/nara.*

Background

The FHWA's Buy America policy in 23 CFR 635.410 requires a domestic manufacturing process for any steel or iron products (including protective coatings) that are permanently incorporated in a Federal-aid construction project. The regulation also provides for a waiver of the Buy America requirements when the application would be inconsistent with the public interest or when satisfactory quality domestic steel and iron products are not sufficiently available. This notice provides information regarding FHWA's finding that a Buy America waiver is appropriate for use of non-domestic stainless steel grooved butterfly valves, grooved couplings, and electrical conduit bodies and fittings for the I–90 project in the State of Washington.

In accordance with Division K, section 122 of the ''Consolidated and Further Continuing Appropriations Act, 2015'' (Pub. L. 113–235), FHWA published a notice of intent to issue a waiver on its Web site (*http://www.fhwa.dot.gov/construction/contracts/waivers.cfm?id=114*) on September 10th. The FHWA received no comments in response to the publication. Based on all the information available to the agency, FHWA concludes that there are no domestic manufacturers of stainless steel grooved butterfly valves, grooved couplings, and electrical conduit bodies and fittings for the I–90 project in the State of Washington.

In accordance with the provisions of section 117 of the SAFETEA–LU Technical Corrections Act of 2008 (Pub. L. 110–244, 122 Stat. 1572), FHWA is providing this notice as its finding that a waiver of Buy America requirements is appropriate. The FHWA invites public comment on this finding for an additional 15 days following the effective date of the finding. Comments may be submitted to FHWA's Web site via the link provided to the waiver page noted above.

(**Authority:** 23 U.S.C. 313; Pub. L. 110–161, 23 CFR 635.410)

Dated: October 16, 2015.

Gregory G. Nadeau,

Administrator, Federal Highway Administration.

[FR Doc. 2015–26984 Filed 10–22–15; 8:45 am]

BILLING CODE 4910–22–P

DEPARTMENT OF TRANSPORTATION

Federal Highway Administration

[Docket No. FHWA–2013–0050]

Final Designation of the Highway Primary Freight Network

AGENCY: Federal Highway Administration (FHWA), Department of Transportation (DOT).

ACTION: Notice; response to comments.

SUMMARY: This notice publishes the final designation of the highway-only Primary Freight Network (highway-only PFN). Section 167(d) of title 23, United States Code (U.S.C.) requires the Secretary of Transportation to establish the highway-only PFN and re-designate it every 10 years, giving consideration to certain factors. This designation meets the requirements of the law, but the Department and a multitude of public comments recognize that the highway-only PFN fails to demonstrate that freight moves through a complex and extensive network of highways, railroads, waterways, pipelines, and airways. While specific commodities are likely to be moved on a particular mode or series of modes, a complex multimodal system is required to carry the growing volume of bulk and high-velocity, high-value goods in the United States. In addition, the 27,000-mile cap required by the law does not yield a PFN representative of all the critical highway elements of the United States freight system. While the Department is designating the highway-only PFN to meet the statutory requirements of the authorizing law, the Department is concurrently and simultaneously proposing a comprehensive Multimodal Freight Network for public comment in the draft National Freight Strategic Plan to identify key infrastructure for all modes that is critical for the efficient movement of freight.

FOR FURTHER INFORMATION CONTACT: For questions about this program, contact Coral Torres, FHWA Office of Freight Management and Operations, (202) 366–7602, or by email at *Coral.Torres@dot.gov.* For legal questions, please contact William Winne, FHWA Office of the Chief Counsel, (202) 366–1397, or by email at *William.Winne@dot.gov.* Business hours for the FHWA are from 8:00 a.m. to 4:30 p.m., EST/EDT, Monday through Friday, except Federal holidays.

SUPPLEMENTARY INFORMATION:

Electronic Access

You may retrieve a copy of the notice through the Federal eRulemaking portal at: *http://www.regulations.gov.* The Web site is available 24 hours each day, every day of the year. Electronic submission and retrieval help and guidelines are available under the help section of the Web site. You may also download an electronic copy of this document from Office of the Federal Register's home page at: *http://www.archives.gov/federal_register* and the Government Printing Office's Web page at: *http://www.gpoaccess.gov.*

Background

Section 167(c) of title 23, U.S.C., directs the Secretary to establish a National Freight Network (NFN) to assist States in strategically directing resources toward improved system performance for efficient movement of freight on the highway portion of the Nation's freight transportation system, including the National Highway System (NHS), freight intermodal connectors, and aerotropolis transportation systems.

Under 23 U.S.C. 167(c), the NFN will consist of three components: The highway-only PFN, the portions of the Interstate System not designated as part of the highway-only PFN, and Critical Rural Freight Corridors (CRFC), which are designated by the States.

The Moving Ahead for Progress in the 21st Century Act (MAP–21) limited the highway-only PFN to not more than 27,000 centerline miles of existing roadways that are most critical to the movement of freight. In addition, MAP–21 allowed an additional 3,000 centerline miles (that may include existing or planned roads) critical to the future efficient movement of goods on the highway-only PFN. The MAP–21 instructed DOT to base the highway-only PFN on an inventory of national freight volumes conducted by the FHWA Administrator, in consultation with stakeholders, including system users, transport providers, and States. The MAP–21 defined eight factors to consider in designating the highway-only PFN.

The eight factors are:

1. Origins and destinations of freight movement in the United States;
2. Total freight tonnage and value of freight moved by highways;
3. Percentage of annual average daily truck traffic in the annual average daily traffic on principal arterials;
4. Annual average daily truck traffic on principal arterials;
5. Land and maritime ports of entry;
6. Access to energy exploration, development, installation, or production areas;
7. Population centers; and
8. Network connectivity.

Section 167(d)(3) of title 23, U.S.C., mandates that the Secretary shall re-designate the highway-only PFN every 10 years. The highway-only PFN announced by this notice is the first iteration of the network.

Multimodal Freight Network

Freight in America travels over an extensive network of highways, railroads, waterways, pipelines, and airways: 985,000 miles of Federal-aid highways; 141,000 miles of railroads; 28,000 miles waterways; and more than 2.6 million miles of pipelines. There are over 13,000 airports in the United States, with approximately 500 serving commercial operations, and over 5,000 coastal, Great Lakes, and inland waterway facilities moving cargo. While specific commodities are likely to be moved on a particular mode or series of modes, a complex multimodal system is required to carry the growing volume of bulk and high-velocity, high-value goods in the United States. For freight shipments moving more than 750 miles (the distance beyond which the benefits of multimodal shipping are more pronounced), 35 percent of U.S. freight by value (including air freight and mails) moves on multiple freight modes. And while 70 percent of freight by weight and 64 percent by value is moved by truck, the goods moved may be processed foods, manufactured goods or other finished products that were carried on other modes or include raw materials that traveled by other modes during an earlier stage of production.

Public comments on the draft highway-only PFN requested consideration of a network that was reflective of the Nation's entire multimodal freight system. While the DOT recognizes that freight is moved through the country by a complex multimodal system, MAP–21 mandated that the highway-only PFN consist solely of ''existing roadways that are most critical to the movement of freight.'' (23 U.S.C. 167(d)(1)(A)(ii)) As a result, the final highway-only PFN announced by this notice does not identify or prioritize other modal aspects of the U.S. freight system.

In recognition of the public comments indicating the need for a multimodal NFN that reflects the key components of each transportation mode in the nation's freight system, DOT is concurrently and simultaneously proposing a comprehensive Multimodal Freight Network (MFN) as part of the release of the National Freight Strategic Plan. The Department engaged all DOT modes with freight relevance (Federal Highway Administration, Federal Railroad Administration, Maritime Administration, Pipeline and Hazardous Materials Safety Administration and the Federal Aviation Administration) in building an MFN to identify key infrastructure for all modes that are critical for freight movement.

As part of this multimodal effort, DOT considered the feedback provided on the designation of the highway-only PFN (described below in this notice) and built a multimodal network using revised thresholds and a modified set of criteria, without the constraints of a mileage cap. This MFN was designed to satisfy the National Freight Policy goals and objectives at a multimodal level. The DOT will seek additional feedback from public and private transportation stakeholders in order to better identify what the goals, objectives and future use of this MFN will be at the regional, State, and local levels. The Department will also work with stakeholders to identify critical urban and rural connectors and corridors.

The GROW AMERICA Proposal

In the Generating Renewal, Opportunity, and Work with Accelerated Mobility, Efficiency, and Rebuilding of Infrastructure and Communities throughout America Act (GROW AMERICA), the Administration proposed to improve national freight policy to give it a multimodal focus. To this end, the GROW AMERICA would streamline existing law by eliminating the highway-only PFN and CRFCs and establish a multimodal NFN to inform public and private planning, to prioritize Federal investment, aid the public and private sector in strategically directing resources, and support Federal decisionmaking. This network would consist of connectors, corridors and facilities in all transportation modes most critical to the current and future movement of freight in the national freight system. The proposal would ensure a more accurate and relevant network by shortening the period of re-designation to a 5-year cycle and would require consideration of public input, including that from Metropolitan Planning Organizations (MPO) and States on critical freight facilities that are vital links in national or regionally significant goods movement and supply chains.

Purpose of the Notice

The purpose of this notice is to publish the final designation of the highway-only PFN as required by 23 U.S.C. 167(d), provide information about the methodology and data used in the designation, and provide an analysis of the comments received on the draft designation of this network.

Final Designation of the Primary Freight Network

With this notice, the FHWA Administrator, based on the delegation of authority by the Secretary, officially designates the final highway-only PFN. This final designation includes the same routes identified in the draft highway-only PFN, previously released on November 19, 2013 (78 FR 69520). Links illustrating the 26,966 miles on the highway-only PFN are available on the Web site maintained by FHWA (*http://www.ops.fhwa.dot.gov/freight/infrastructure/pfn/index.htm*). The DOT provides this final highway-only PFN to comply with the requirements of 23 U.S.C. 167. However, due to the challenges experienced in developing a network that would adhere to MAP–21 requirements and convey the full nature of the Nation's freight system, the Department recommends consideration of an alternative multimodal network using a revised methodology that includes criteria supported by the public comments on the designation of the highway-only PFN, such as the one proposed in GROW AMERICA or provided for public comment in the draft National Freight Strategic Plan.

Analyses of Comments on the Draft Designation of the Highway-Only PFN and NFN

On November 19, 2013, FHWA published the draft designation of the 27,000-mile highway-only PFN in the **Federal Register** at 78 FR 69520. The initial notice also provided a larger network of routes (a 41,518-mile comprehensive highway-only PFN) for consideration and information regarding State designation of the CRFCs and the establishment of the complete NFN. The FHWA asked stakeholders to review the draft highway-only PFN and provide feedback.

Stakeholders requested additional time to analyze the draft highway-only PFN methodology, maps, and the highway-only PFN's potential impact on their communities. In response to these requests, FHWA twice extended the public comment period. The comment period closed on February 15, 2014, at which point the docket recorded a total of 307 responses, including over 1,200 discrete comments. The following section presents a quantitative and qualitative analysis of the trends, themes, and patterns identified in the public comments.

Comments by Organization Type

The initial highway-only PFN notice generated comments from a range of stakeholders in the private and public sectors. The following table identifies the number and percentage of comments received by organization type. The majority of comments came from MPOs, local government agencies, and State DOTs.

Public or private stakeholders	Organization type	Number of comment entries	Percentage of comments [1]
Private	Business	22	7.2
	Industry Association	21	6.8
	Private Citizen	21	6.8
Public/Private	Port	12	3.9
	Other	33	10.7
Public	State DOT	51	16.6
	Federal Agency	2	0.7
	Foreign	1	0.3
	Local Government Agency	64	20.8
	Metropolitan Planning Organization	68	22.1
	Other State Agency	5	1.6
	Regional Commission	2	0.7
	Congress	5	1.6
Total		307	100.0

Comments by Subject Area

The FHWA asked stakeholders to review the draft highway-only PFN and provide feedback on five topics:

1. Specific route deletions, additions or modifications to the draft designation of the highway-only PFN as outlined in the notice;
2. The methodology for achieving a 27,000-mile final designation;
3. How the NFN and its components could be used by freight stakeholders in the future;
4. How the NFN may fit into a multimodal National Freight System; and
5. Suggestions for an urban-area route designation process.

Most responses addressed two or more of the five topics, with 33 percent focusing on the methodology and 21 percent commenting on route deletions, additions, or modifications.

Type of comment	Number of comments	Percent of total comments [2]
1. Specific route deletions, additions or modifications	267	21.2
2. Methodology for a 27,000 mile designation	419	33.3
3. NFN use by freight stakeholders in the future	105	8.4
4. NFN and a multimodal National Freight System	135	10.7
5. Suggestions for an urban route designation process	174	13.8
6. Funding Issues	108	8.6
7. Request for Comment Extension	6	0.1
8. Other	43	3.4
Total Comments	1,257	100

Specific Route Additions, Deletions or Modifications

The highway-only PFN Web site provides information on the requested additions, deletions and modifications to the highway-only PFN as well as a map reflecting these routes and segments, which totaled approximately 8,400 additional or modified miles and 230 miles proposed for deletion. This information can be found in the following Web site: *http://www.ops.fhwa.dot.gov/freight/infrastructure/pfn/index.htm.*

Additions

The majority of comments related to route changes suggested that FHWA consider the addition of specific road

[1] Due to rounding, figures do not add to 100 percent.

[2] Due to rounding, figures do not add to 100 percent.

segments and facilities. However, in some cases, respondents requested that entire State and Interstate highways be included. The comments requesting that routes be added to the highway-only PFN most often cited one of the following reasons:

1. Incorporating roads necessary for improving current freight movements;
2. Incorporating roads necessary for planning future commodity growth on the segment;
3. Affirming local freight planning efforts that identified the segment and/or facility as a major critical freight route or generator;
4. Incorporating roads necessary to close gaps and connect one facility, city, region, or State to another;
5. Incorporating roads necessary for resolving omissions of key segments and facilities such as those with major significance to national security and/or goods movement. Examples include: military facilities, airports, ports, bridges, rail yards and intermodal connectors;
6. Including the ''first'' and ''last'' mile of freight movements on routes designated in the draft highway-only PFN;
7. Incorporating a route or facility related to an international trade corridor;
8. Incorporating roads based on traffic counts and truck data indicating the segment is a critical link in the area's freight network;
9. Incorporating roads identified in the past by FHWA as a ''Corridor of the Future'' or that may become critical to the future movement of freight; and/or,
10. Including new, planned roads that, when constructed, will—
   - Provide continuity in the freight network;
   - Provide a connection to population centers;
   - Provide connectivity to intermodal facilities;
   - Relieve congestion on existing Interstates; and
   - Provide benefits to national commerce as a route in a long-distance trucking corridor.

Deletions and Modifications

Some respondents submitted requests for deletions and/or modifications to the highway-only PFN. The reasons offered for these requests included the following:

1. A desire to emphasize a different or more logical route than that included in the highway-only PFN (respondents often expressed that their agencies conducted evaluations using a different methodology or criteria that yielded other routes as more freight-relevant than the ones proposed in the draft highway-only PFN);
2. A desire to discourage non-local truck traffic through an area such as a neighborhood, commercial district, or downtown; requests to remove local streets not connected to freight facilities; and
3. Erroneous or outdated facility names.

The FHWA appreciates the comments requesting additions, deletions, or modifications to the draft highway-only PFN. In analyzing the route-related comments, FHWA determined that the level of information or data solicited in the draft highway-only PFN designation and provided through comments did not provide the specificity necessary to make accurate or consistent modifications to the network. For example, in order to change a route designation it is important to have mile marker identification of segments and common data years (in the case of data-driven segments). Although some respondents provided information such as beginning and end points or name of a route or facility (such as a specific intermodal connector), their requests to add, delete, or modify the designation of the routes and facilities did not comply with the criteria and threshold used for the draft designation, or different data sources were used as a justification.

Despite the lack of specificity in the data provided by commenters, many additions and modifications reflected some aspect that FHWA considers relevant for the efficiency, reliability, safety, and sustainability of the freight system and may have been incorporated into the highway-only PFN if not for the current mileage cap imposed by the law. Therefore, although no route modifications were made for the final designation of the highway-only PFN, FHWA considered these requests in its development of an alternative multimodal freight network, which is discussed in further detail in the National Freight Strategic Plan as displayed here: *http://www.transportation.gov/policy/freight/NFSP.*

Methodology for Achieving a 27,000-Mile Designation

Approximately 420 comments addressed the methodology for achieving a 27,000-mile designation. The commenters expressed concern regarding the complexity of the process for developing a highway-only PFN that incorporates the criteria identified in MAP–21 and appreciated the challenge of adhering to only 27,000 centerline miles of roads. Other comments were critical of the criteria, concept, and data used for the designation. The following subsections summarize comments on the methodology.

Limitations of the 27,000 Centerline Miles Threshold

Comments regarding the highway-only PFN's centerline mileage threshold expressed concern that combining multiple network criteria with a mileage cap does not yield a highway-only PFN representative of the most critical highway elements of the United States freight system. Virtually all respondents preferred the sample 41,518-mile ''comprehensive'' (yet highway-only) network offered by DOT for comparison. Some respondents recommended that DOT work with Congress to develop statutory language to designate a more comprehensive and connected highway freight network that links directly to other freight modes. These commenters asked that Congress either (1) eliminate or raise the mileage threshold, or (2) use a corridor basis instead of the statutorily required centerline roadway mile basis. Some respondents sought a connected 27,000-mile network of key freight routes but did not provide a specific set of criteria. Others proposed that the highway-only PFN incorporate the entire Interstate System in a non-statutory designation. Respondents also noted that the comprehensive network (*e.g.,* the 41,518-mile network) included many of the highway freight routes necessary to ensure sufficient connections to Land Ports of Entry (LPOE) to Mexico and Canada and maritime ports of entry in coastal states that are important for the Nation's global competitiveness.

Section 167 of title 23, U.S.C., specifies that the highway-only PFN designation cannot exceed a cap of 27,000 centerline roadway miles. Therefore, in order to comply with Federal law, the final highway-only PFN designation comprises no more than 27,000 centerline miles (and includes the LPOEs for the most freight-active border crossings by truck volumes).

Highway-Only PFN Criteria and Designation Methodology

This subsection discusses the comments on the statutory criteria and the methodology developed by FHWA for the highway-only PFN designation process. Some respondents proposed reconfiguring the highway-only PFN to connect significant freight origins and destinations for agriculture, energy production, manufacturing, mining, and national defense to other key infrastructure such as the Interstate system, ports of entry, and intermodal connectors. Some respondents expressed concern that agriculture was not listed as a specific factor for consideration. They felt that the factor pertaining to the value of goods failed to give sufficient weight to the movement of agricultural products. These respondents commented that the NFN should directly address the importance of agriculture to the U.S. and, without this focus; the resulting network would be flawed. They suggested the use of criteria to better reflect the movement of agricultural products by truck from field to market, directly or by railheads, rather than measuring the movement of imported goods. These commenters cited domestic agricultural commodities as being vital to the U.S. economy and the health and well-being of the U.S. population and stated that agricultural goods are among the most significant generators of truck-freight in several States. Some of these respondents commented that identifying routes in the NFN can enhance energy, agricultural, and natural resource freight movement and provide new opportunities for economic development.

In response, FHWA acknowledges that to better represent the movement of agricultural products on the freight system, it would be necessary to consider the data and the road-, rail-, air- and water-based routes of a multimodal freight system. National data shows agricultural products as being some of the top commodities under current models and forecasted trends. The current highway-only PFN methodology does not prioritize for type of commodity and was intended to be supplemented by CRFCs that could include routes serving key agricultural facilities. The FHWA believes a multimodal freight network map would more accurately depict the movement of agricultural commodities, which move by truck, rail, or barge, or combinations of these methods.

Respondents also expressed concern for the lack of sensitivity in the model to routes seasonal fluctuations and spikes in volumes that have low annual averages, such as agricultural or forest products routes and energy development, production, and extraction areas. They felt that the freight mileage on these routes does not meet the highway-only PFN threshold yet still accommodates a degree of truck traffic relevant for inclusion in the network. Some comments proposed a separate prioritization process for seasonally critical agricultural corridors beyond the CRFCs designation established in MAP–21 and a shorter re-designation cycle of the NFN and highway-only PFN to better capture these trends.

In response, FHWA acknowledges that additional research, data and refinements to the model could be developed to capture freight surges. The FHWA will consider opportunities for incorporating seasonality or surges into future network development.

Respondents also suggested modifications to the methodology and different thresholds for the criteria. Some noted that the initial step of the methodology should be changed to identify critical freight nodes. In this alternative methodology, the highway-only PFN would represent roadways that support certain critical freight nodes rather than a subset that carry the most freight (the format for the current methodology). The alternative methodology would then use additional analysis to define the subset of roadways most critical to serve these nodes. Respondents noted that by focusing on identifying critical roadways closest to freight nodes, this methodology would better assist States in strategically directing resources toward improved system performance for efficient movement of freight on the highway portion of the Nation's freight transportation system.

In response, FHWA notes that it explored the development of a highway-only PFN that started with critical freight nodes (predominantly urban areas and freight-intensive border crossings) and built out from these points. After analyzing the data and simulating the network, the Department selected a hybrid approach that used origin and destination data from the Freight Analysis Framework (FAF) and cross-referenced it with these nodes using Average Annual Daily Truck Traffic (AADTT) as a guide for how freight moves, by both tonnage and value, between nodes. There are many ways to develop the highway-only PFN, and that is in part why the FHWA sought public comment on the methodology. The FHWA felt that a node-based map would require leaving routes within a node undesignated, as FHWA lacked data specificity for these routes. As a result, use of a node-based map would require an additional step and time to obtain public input or to develop better data.

The comments noted that while the methodology itemized several factors considered for the draft network, it appears the base was drawn using AADTT and then adding or subtracting to accommodate each of the other factors. Respondents believed this may give undue weight to densely populated regions with the associated large regional distribution movements. Respondents also noted that this led to illogical results that appear to be related to data discrepancies between States.

Comments also addressed thresholds for the criteria used for designation. Several comments flagged the limits for AADTT and population used in the designation process as being too high. In particular, comments noted that the AADTT threshold of 8,500 trucks to identify roadway segments was set too high and precluded the establishment of a rational and connected national network, which they argued was the fundamental task of the national designation. Respondents advocated for a percent of trucks in the AADTT and a 1,500 AADTT threshold for the highway-only PFN. The commenters felt that these changes could provide a more useful picture of the freight economic corridors the Nation relies on to support interstate and international commerce.

Respondents also noted that the functional classification of roadways should be changed to include collectors and above, and to consider the allowance of lower vehicle classifications of truck traffic. Others argued that the percentage of trucks should not be the deciding factor but rather one of many factors considered for highway-only PFN designation, including connectivity to and between freight facilities. Finally, respondents believed the 25 percent AADTT requirement proposed for designating a CRFC corridor would be too restrictive for identifying urban area routes; they proposed using a separate data threshold for urban area freight corridor designation.

In response, FHWA acknowledges that AADTT levels had a fundamental role in the highway-only PFN designation process. The FHWA selected the AADTT and percent of truck traffic thresholds to meet the 27,000-mile limitation set in statute. The CRFC threshold of 25 percent truck traffic was set by statute in MAP–21. When identifying data from certain roadway classification and truck types, the FHWA focused on aspects of freight that would be most relevant to national goods movement, while also limiting the scope of the highway-only PFN to meet the mileage threshold.

Respondents expressed that to develop the highway-only PFN effectively, FHWA must provide a stronger consultative role for State DOTs to identify the critical individual State components of the highway-only PFN. They felt that FHWA should build as much flexibility into the designation process as possible, especially by providing the States with an opportunity to identify an alternative network of freight highway routes or corridors. Further, the States were thought to be in the best position to regularly review the designated network for updates and revisions.

In response, FHWA agrees that involvement of State DOTs, MPOs, local agencies, and the private sector is key to developing a national or primary freight network. The FHWA also recognizes the need to have national consistency in the approach and scale of facilities included on a freight network. The FHWA encourages States to use State Freight Plans and to consult with State Freight Advisory Committees to identify facilities most critical to freight movement in each State.

A few comments recommended using the United States Census definition for urban areas instead of those with a population of 200,000 or more. In the Census definition, urbanized areas consist of territory that contains 50,000 or more people. Respondents criticized FHWA's use of the higher population threshold to meet the ''arbitrary'' limit of 27,000 centerline miles. Respondents noted that significant national and international trade flows to and from mid-size communities across the country are missed at the 200,000 population level.

In response, FHWA recognizes that the approach employed for connecting population areas of 200,000 or greater risks bypassing areas of important freight activity. However, FHWA encountered difficulty keeping the highway-only PFN to under 27,000 centerline roadway miles under scenarios that included all population centers of 50,000 or more people.

Furthermore, the lack of a stated application for the highway-only PFN and NFN introduced uncertainty into the designation process. Without a better understanding of the goals for the highway-only PFN, it was challenging to weight the factors for designation and to gauge which resulting network would best meet freight planning and investment needs. Each individual criterion yields different network coverage when compared to the other factors. The FHWA undertook an extensive research effort to fully understand the challenges of the proposed criteria and to develop a methodology that would generate the most comprehensive network. This resulted in dozens of scenarios that did not satisfy the mileage cap or the inclusion of all of the statutory criteria. The aggregation of these factors results in a map that is difficult to limit to 27,000 miles without some significant prioritization of the factors and their thresholds. Further, FHWA acknowledges that the 27,000-mile highway-only PFN does not meet the statutory criterion for network connectivity. To fix these problems, the alternative methodology applied by FHWA during the highway-only PFN development resulted in the second, comprehensive map that exceeded the statutory cap but is inclusive of all the criteria suggested in MAP–21 and reaches more population centers.

Centerline Versus Corridor Approach

The majority of respondents expressed concern regarding the fragmented nature of the highway-only PFN. While it was widely understood that the non-contiguous highway-only PFN resulted from a need to meet competing statutory factors under a mileage threshold, respondents recommended that FHWA designate a continuous and linked multistate network of transportation infrastructure that provides a high level of support for international, national, and State economies. Some suggested the highway-only PFN use a corridor approach instead of the statutory requirement for measuring centerline roadway miles. Respondents agreed with FHWA's suggestion that corridor-level analysis and investment has the potential for widespread freight benefits and can improve the performance and efficiency of the highway-only PFN.

These respondents provided suggestions for a more comprehensive corridor-based approach to the highway-only PFN to designate multiple parallel routes in each region that provide a high level of support for international, national, and State economies and connect regional population and economic centers. Comments noted that the use of corridor miles rather than centerline miles would allow greater flexibility for States and local jurisdictions for funding opportunities and in applying future performance measures, not only to a single identified route but also to important intermodal and urban connectors as well as nearby parallel routes for use in freight-related congestion mitigation. In addition, commenters noted that these corridor designations will better correspond to a truly multimodal freight network to avoid or allow (as needed) route redundancies between all surface modes.

In response, FHWA agrees that a corridor approach for a highway network allows for coverage of multiple routes as well as freight facilities that satisfy the criteria in MAP–21. However, such an approach will not meet the centerline highway miles requirement of MAP–21. Also, because MAP–21 directed the Secretary to create a highway-only PFN, the lack of consideration of water freight and rail freight movements yields an incomplete representation of the nation's freight corridors.

Data Limitations and Accuracy

The majority of comments that discussed the sources and limitations of data agreed that the national data sets utilized in the development of the draft highway-only PFN were insufficient to understand fully the behavior of freight at the regional and local levels. Respondents mentioned that the data used to develop the highway-only PFN do not accurately reflect freight movements at the State, regional, and local level and that the designation of this network relies on outdated information. Points raised included concerns that existing sources of data are fragmented, incomplete, and often not useful in supporting transportation operations, policy, and investment decisions. For example, one State noted that the Functional Classification Evaluations in their State had not been updated for over 20 years.

Respondents also expressed a view that the quality of the Highway Performance Monitoring System (HPMS) data, which were used to identify AADTT, varies greatly from State to State and depends upon the quantity and location of counts, the age and frequency of counts, and the upkeep of counting equipment. Respondents also felt that the highway-only PFN methodology did not take into account more complete and accurate data available from States, MPOs, and other local stakeholders. Comments suggested that FHWA coordinate with the States and their planning partners to ensure the currency and validity of the data sources that support the analyses conducted over the course of MAP–21 policy development and implementation. Respondents suggested that the next reauthorization fund a comprehensive data program that enables DOT, States, and MPOs to undertake the freight analysis and planning called for in MAP–21 at the national, State, and regional levels. Comments indicated that such a program should include safety data. Because significant freight facilities for energy transport appear in more remote areas and in outlying urban areas, respondents noted that data should capture information in rural and smaller outlying urban areas, as well as major metropolitan centers.

Comments noted that access to private sector data is needed as well as other proprietary sources of real-time data. Respondents noted that such data can be used to map the most critical first- and last-mile segments, including rural areas. Comments also recommended giving DOTs and MPOs access to reliable and inexpensive data to conduct sound planning.

In response, FHWA notes that goods movement occurs in a very fluid environment. During the development of the draft highway-only PFN, and as an internal reference point of comparison to an earlier mapping effort, FHWA took the major freight corridors map that was originally developed for Freight Story 2008 and ran an analysis in the spring of 2013 to see how that map would look using current data. The Freight Story 2008 map contained 27,500 miles: 26,000 miles based on truck data and parallel intermodal rail lines and 1,500 miles representing goods movement on parallel major bulk rail lines or waterways. Using the same methodology with 2011 HPMS and rail data, data revealed that the mileage based solely on the truck and intermodal rail activity had grown to over 31,000 miles of roads since 2008, not including consideration of growth in other freight modes on parallel major bulk rail lines or waterways.

The FHWA recognizes that the data utilized for the development of the final highway-only PFN comprises the best information available on freight behavior at a national level. Nevertheless, national data is not sufficient to understand fully the behavior of freight at the regional and local levels. In particular, urban areas include a freight-generating population and in most cases, are the site of significant freight facilities where highway freight intersects with other modes at rail yards, ports, and major airports. These ''first- and last- mile'' connections, which also occur in rural areas, do not always show up in data sets. In order to develop a network that provides a better picture of freight in urban and rural areas, additional data collection at State and local levels is needed to improve the assessment of local and regional freight trends. This will require coordination with stakeholders at a local, State, and regional level. This data could provide a better understanding of seasonal and regional trends around the country that national data sets often do not capture.

The FHWA acknowledges a continuing national need for more robust data collection methods. The FHWA also acknowledges that additional coordination with MPOs and State DOTs is needed for future designation of the highway-only PFN and any other freight networks to address some of the data issues of the final highway-only PFN. As part of its development of an MFN and for any future designation of the highway-only PFN or other freight networks, DOT will seek additional coordination with MPOs and State DOTs to address some of the outlying issues remaining in this iteration of the network.

NFN Use by Freight Stakeholders in the Future

Because MAP–21 did not provide a specific purpose for the highway-only PFN, it was challenging to establish thresholds in the methodology and prioritize criteria to achieve the mileage limitation when it was unclear how the highway-only PFN and the NFN would be utilized. To better inform the process, FHWA sought comments on how the NFN and its components could be used by freight stakeholders in the future. A number of respondents echoed the concern that the future use of the NFN and highway-only PFN could not be identified without understanding its purpose and goals in relation to transportation policy and programs. Respondents requested additional information from DOT and Congress, with some recommending that the next transportation bill clearly identify a policy and provide funding for NFN or highway-only PFN facilities.

Many comments linked the highway-only PFN to funding, believing the highway-only PFN would be eventually be used to prioritize funding for projects. Some respondents proposed that Congress use this network for strategic investment in freight on a national network of key freight routes by specifically directing Federal highway funding through a formula program apportioned to States. They felt it would be appropriate for Congress to direct most of this funding to the NFN, with the addition of urban routes. There was concern about using the more limited highway-only PFN to allocate or apportion resources without making adjustments to the methodology. Suggestions for improving the map for directing investment included using the NFN, which includes the Interstate System, and adding urban routes, intermodal connectors, and last- and first-mile connectors.

Some respondents indicated funding should not be directed until the designation is vetted by States and MPOs and that resources should not be directed away from other highway programs to fund NFN-related projects. Respondents also suggested that DOT work with Governors to develop and evaluate funding options for a multimodal NFN that takes into account States' transportation infrastructure assets and limitations as detailed in State Freight Plans. The notice elicited concerns relating to restrictions on the ability to shift infrastructure funding to non-designated facilities and the potential assessment of freight user fees.

Other commenters were concerned that the NFN or highway-only PFN would be used in the future to impose restrictions on how the designated infrastructure could be used or impose minimum investment requirements. In addition, commenters raised concerns regarding the ease and speed of the re-designation process. Commenters also cautioned against using this network to direct the use of private property. Respondents requested that these and other potential issues be given consideration and that the government offer carefully structured and definitive guidance. In the absence of such guidance, respondents stated that they could not fully support the designation of any infrastructure, public or private, as a part of the highway-only PFN.

Respondents viewed the NFN as a tool to facilitate a closer working relationship between the government and private sectors who share an interest in a fully-functioning freight system. Having State DOTs, MPOs, trucking companies, the manufacturing and warehousing industries, and other highway freight stakeholders participate in a closer working relationship would be helpful to determine where limited highway funding can best be invested and where it will have the greatest and most widespread positive return on investment. Respondents supported the use of the network to strategically direct resources to improve system performance for efficient movement of freight on the highway portion of the National Freight System. They projected that the most important outcome would be the ability to identify and focus attention on the highways and related projects that would target freight mobility problems and lead to improved freight flow to maintain and enhance U.S. economic activity.

Respondents mentioned that the NFN may be a useful resource or tool in developing State Freight Networks and State Freight Plans. Respondents felt that designation of a highway-only PFN could aid States in such freight planning efforts as the designation of CRFCs, the development and update of State Freight Plans, input to State Freight Advisory Councils, and other planning activities. Respondents recommend that FHWA give greater weight to factors that States suggest, including consideration of State Freight Plans that may already be developed.

Respondents commented that the highway-only PFN could provide the locations to target for valuable data collecting efforts to measure the fluidity of highway freight network. For example, the identification of segments with the highest AADTT could provide the location of potential capacity constraints and congestion issues.

In response, FHWA appreciates the concerns related to the lack of a stated application for the highway-only PFN and NFN. Without a better understanding of the goals for the highway-only PFN, the FHWA found it challenging to weight the factors for designation relative to one another and to gauge whether the resulting network would meet future public planning and investment needs. Each individual criterion yields different network coverage when compared to the simulations for the other factors. The aggregation of all the suggested criteria resulted in a map that was difficult to limit to 27,000 miles without some significant prioritization of the many factors and application of numerical thresholds in each measure.

The FHWA believes a multimodal NFN as described in the Department's GROW AMERICA surface transportation proposal will have the ability to inform public and private planning, to help prioritize for Federal investment, to aid the public and private sector in strategically directing resources, and to support Federal decisionmaking to achieve the national freight policy goals.

NFN and Multimodal National Freight System

Respondents provided feedback on how the NFN fits into a larger multimodal national freight system and how to define a multimodal national freight system. Nearly 11 percent of the comments addressed this topic. The majority of respondents on this topic acknowledged that the highway-only PFN is a highway-only network and that the highway-only PFN and NFN are therefore incomplete in their representation of the multimodal system that is required to efficiently and effectively move freight in the United States. The FHWA agrees with these comments.

Comments suggested the highway-only PFN be designated in a way that would ensure future inclusion of the other freight modes that comprise the Nation's freight and goods transportation system. Respondents also voiced concern that the draft highway-only PFN did not include most of the segments that make up the first and last mile of key freight movements, which include local roads providing access to ports, intermodal facilities, rail yards, and other freight facilities. FHWA agrees with these comments.

Most respondents recognized these omissions were the result of the mileage cap and recommended FHWA advocate for the elimination of the mileage threshold. The FHWA agrees with these comments and has taken action by addressing this in both the Department's GROW AMERICA surface transportation proposal and the National Strategic Freight Plan.

Respondents believe that the highway NFN could be an important modal component of a multimodal national freight system, but that the NFN is not sufficient to describe the entirety of a system that moves freight by a variety of modes. The FHWA agrees with these comments.

Some comments strongly encouraged DOT to focus the National Freight Strategic Plan and other freight transportation work on the entire multimodal freight system, and recommended that the final highway-only PFN and NFN maps be overlaid with intermodal connectors, ports of entry, marine highways (waterborne routes), important inland river corridors and Class 1 rail lines to show a more comprehensive surface transportation network critical to the movement of freight. The FHWA agrees with these comments and has followed this recommendation.

Comments indicated the NFN should be combined with the other modes of transportation to form a true multimodal system that operates economically, efficiently, and harmoniously in the movement of freight both nationally and internationally. Respondents suggested building upon the FHWA's initial 41,518 centerline mile highway network as a basis for ultimately developing a more comprehensive, multimodal freight network. In addition, comments noted that FHWA and State DOTs should compare the highway freight network map with strategic freight railroad, waterway system, and aviation maps to locate connectivity gaps. Commenters recommended that highway routes connecting to intermodal facility locations be included in the NFN to ensure that the network reflects a well-connected multimodal freight system. The FHWA agrees with these comments and believes this is an activity that should be undertaken by DOT in consultation with States and MPOs.

Many respondents supported the expansion of this network to a more broadly defined multimodal network. They recommend that dedicated funding be made available to support projects included in an approved Regional Transportation Plan to enhance the performance and efficiency of the highway-only PFN and NFN, as well as to mitigate adverse freight movement impacts on surrounding communities and include eligibility for highway-rail grade separations and other mitigation projects located along nationally significant trade corridors.

In summary, FHWA agrees with the comments. In response to these recommendations, FHWA is providing the final designation of the highway-only PFN as required by MAP–21, while concurrently and simultaneously releasing a MFN as part of the National Freight Strategic Plan. The release of this Plan coincides with the issuance of this notice, and the Department will seek public comment on its proposed MFN.

Suggestions for an Urban-Area Route Designation Process

State DOTs and MPOs provided comments in partnership with freight facility owners in support of a metropolitan area designation process similar to the CRFC designation. The comments included suggestions for methodologies and more precise data that could be used in the identification of these critical urban freight routes. Almost 14 percent of total comments related to this topic.

Supporters felt this additional network modification is necessary to improve the accuracy and utility of the highway-only PFN. These commenters felt that the next reauthorization should make provisions for designation of urban freight routes and connectors. It was noted that metropolitan areas are the economic engines of the 21st Century economy and that most of the population and most of the high-value and high-tech manufacturing is in metropolitan areas. Comments also noted that much of the cost of moving freight is the result of the congestion encountered in urban areas.

Respondents envisioned that the FHWA would reach out to local stakeholders to establish a formal urban-area route designation process and methodology. They felt strongly that State DOTs and urban representatives should be allowed to provide input on what factors might drive urban designations within the highway-only PFN. Respondents indicated they believe that State DOTs, MPOs, and other local agencies have the knowledge and data to identify the critical urban-area freight corridors and therefore these agencies should be responsible for identifying the critical urban routes and submitting these to FHWA.

Some comments proposed that FHWA provide the framework and basic guidelines for designation, but give States the ultimate responsibility in establishing parameters and thresholds, in addition to identifying the routes for inclusion in the network. The limits to be set by the States and localities, as proposed by the commenters, would take into consideration the freight demand relative to a State's population, consumption and production, and commodity flows for designating both rural and urban freight systems.

Respondents suggested the use of the following criteria for the Critical Urban Freight Corridors (CUFC) designation: (1) High truck volume corridors; (2) strategic military facilities; (3) connections to major intermodal facilities; (4) significant freight intensive land uses on manufacturing and warehouse industrial lands; (5) energy exploration, development, installation, or production areas; (6) areas of significant congestion and delay for trucks; (7) locations of at-grade highway rail crossings; (8) number and severity of truck crashes; (9) geometric deficiencies that inhibit safe or efficient truck movement; (10) negative community/environmental impacts caused by truck traffic; (11) motor carrier enforcement and safety efforts; (12) availability of overnight or safe truck parking; (13) connections between major points of entry or key trip generators and the highway-only PFN (supported by locally derived data and analysis); (14) connectivity with the other elements of the NFN; and (15) freight value. Commenters did not support the inclusion of truck percent of AADT because they felt that it had little relevance in urban areas.

Respondents expressed the view that both the national freight strategy and the networks should include consideration for the urban first and last miles needed to make a complete freight trip.

Others suggested that FHWA should not set the thresholds for truck volume and percent for urban areas, but instead should require that each State set the truck volume and/or truck percent thresholds for their State. The commenters suggested that the context of percent truck traffic and/or truck volumes varied significantly across the country with regard to each State's consumption or production of goods and services and as a result, the thresholds should not be standardized for the Nation.

In addition, comments noted that States should be responsible for working with State freight stakeholders as well as MPOs and Rural Planning Organizations (RPO) in the designation of such systems within their respective State and that States should coordinate with neighboring States to ensure systems take into consideration multistate freight flows. They also noted that as with the CRFC designation process, this process should allow flexibility for States and metro areas to determine the most strategic and important freight routes.

Respondents believed that engaging State DOTs and MPOs in proposing urban-area freight routes would maximize the utility and relevance of each agency's existing freight planning processes, plans, and study initiatives. They felt that by elevating the responsibility of State and local entities to identify criteria, set targets, and identify CUFCs, freight planning would be in the forefront and freight plans would be aligned with other transportation, economic development, and environmental plans or programs.

In response, FHWA recognizes that many highway freight bottlenecks, chokepoints and first and last mile connectors are located in both rural and urban areas. This makes these areas critical to the efficiency of domestic and international supply chains. Although Federal law provided a mechanism to enable connectivity to critical freight ''last mile'' origins and destinations in rural areas through the designation of CRFC by the States, the language in 23 U.S.C. 167(d) lacks a parallel process for designating critical urban freight routes to address the need for connectivity to urban areas. Further, public and private sector representatives are increasingly emphasizing the significant role of cities and metropolitan areas in the safe and efficient movement of freight.

Given the lack of precision of national data at the urban level, FHWA believes there is merit in establishing a process for MPOs, RPOs, and State DOTs to designate critical urban freight routes and critical rural freight corridors that may have been missed when analyzing national-level data but are nonetheless important for freight movement to, from, and through an urban and rural areas. The FHWA recognizes that cities are best positioned to understand the complexities of freight movement in individual urban and rural areas, including current freight movement patterns, and plans or projections for shifts in freight movement within these areas, and could assist in the identification of thresholds for use in the designation of CUFCs.

In response to these comments, FHWA has begun developing preliminary concepts to aid in the designation of freight corridors should they be included in future legislation. The Department has also included language in GROW AMERICA surface transportation proposal that incorporates additional criteria in a NFN designation that gives consideration to bottlenecks and other impediments contributing to significant measurable congestion and delay in freight movement, facilities of future freight importance based on input from stakeholders, and an analysis of projections for future growth and changes to the freight system. In addition, the Department included language that considers elements of the freight system identified and documented by States and MPOs using national or local data as having critical freight importance to the region as part of the NFN.

Funding Issues

Nearly 9 percent of total comments received mentioned funding. In general, respondents believe that the value of the highway-only PFN is limited without the provision of dedicated resources to address freight needs. Some referenced the need for these funds to maintain and enhance a multimodal national transportation system. Some commenters felt that existing Federal funding should not be diverted to the NFN unless current program funding levels could at least be maintained or expanded. Comments also noted that State DOTs and MPOs cannot fully comment on the impact of NFN designations without understanding the potential funding implications, which are not addressed in MAP–21. Further, they cautioned that the NFN should not be used to direct State or Federal investment in freight transportation systems until the network has been revised to reflect highways that serve continuous and efficient freight flow.

The commenters also suggested that planning and policy work would be of limited value if funds are not provided to realize the planning vision. Comments noted the highway-only PFN and an expanded multimodal national freight system could help make the case for a program that leverages local, regional, and private funds to invest in critical freight infrastructure needs.

Others respondents expressed concern about supporting a system that lacks connectivity and does not accurately represent freight trends. As previously discussed in this notice, some respondents recommended refraining from using the NFN for directing State or Federal investment in freight transportation systems. They noted that when the NFN has been restructured to reflect highways that serve continuous and efficient freight flow and is supported by Federal funds accordingly, freight stakeholders should be able to use this system as a benchmark around which to center economic activity and investment. Others mentioned that they will likely focus investment and other decisions on the strategic freight network designated in their State freight plan rather than the NFN. Comments noted that some jurisdictions have already designated a strategic freight network of key corridors which connect additional areas of the State and provide redundancy to Interstate corridors.

Most respondents expressed new funding should be prioritized to support sustainable economic vitality and global competitiveness for the U.S. Some respondents stated that this funding program should support national freight movement through enhancing the NFN by funding highway traffic count stations, truck weigh stations, truck rest area facilities, state of good repair for freight-traveled pavement and bridges, and operations management priorities such as congestion management and travel time reliability. Respondents suggested that funding could also be made available to support freight projects included in an approved Regional Transportation Plan or Transportation Improvement Program. In their view, these projects should be prioritized on the basis of demonstrable contribution to the performance and efficiency of the highway-only PFN and NFN, as well as to mitigate adverse freight movement impacts on surrounding communities.

Respondents also noted that although MAP–21 provides modest funding for the Projects of National and Regional Significance (PNRS), they felt that the PNRS program should be expanded to provide freight funding using a more robust, multimodal PFN. They suggest an expanded PNRS program should build on considerable past efforts, including the freight corridor designations and funding program established under the previous Federal transportation authorization, the Safe, Accountable, Flexible, Efficient Transportation Equity Act: A Legacy for Users (SAFETEA–LU).

In response, FHWA recognizes the need for additional freight investment in the U.S. That is why the GROW AMERICA proposes a six-year, $9 billion multimodal freight incentive program and a 6-year, $9 billion national freight infrastructure program. Given the increased emphasis on transportation performance management, FHWA believes it is prudent not to limit funding to a specific facility on a network map but to allow State and local governments, the private sector, and other entities to determine the best solutions to improving the safety and efficiency of the freight system through data and analysis in State Freight Plans and with the active engagement of the State Freight Advisory Committees.

Other Issues Raised in Comments

The sections below summarize comments received on other issues raised in response to the solicitation of comments on the draft highway-only PFN.

Primary Freight Network Update Cycle

Several comments raised concerns regarding the 10-year timeframe for updating the highway-only PFN. Comments expressed that this length of time does not reflect the changing nature of economic patterns and goods movement. Comments noted there are constant changes in market trends, population, infrastructure, technology, data, demographics, globalization, and investment. Respondents believe that a 10- or 20-year cycle will not allow policy makers and stakeholders to make optimal use of time, resources, and funding. With the MPO planning process based on a 4-year cycle, and freight and rail plans updated on 5-year cycles, respondents recommended FHWA pursue reducing the update cycle to match other metropolitan transportation planning cycles or at a minimum, provide an amendment process that enables States to request and receive approval for highway-only PFN changes between 10-year updates.

In response, FHWA agrees that the current 10-year update cycle is not sufficient. The FHWA does not have statutory authority to change the re-designation cycle but has proposed a 5-year update cycle in the GROW AMERICA surface transportation proposal. The Department will also be proposing a 5-year update cycle as part of the MFN in the National Strategic Freight Plan.

Highway Safety Considerations

A small number of respondents raised the issue of highway safety and the highway-only PFN. Stakeholders noted that safety issues and performance measures should be considered in the establishment of the NFN. These comments emphasize that safety data needs to be part of the analysis and improving safety on our freight systems should be a goal of any Federal action related to the establishment of a NFN. Comments noted that factors should include freight moved by trucks, truck crash rates, the underlying causes of highway deaths and injuries, and infrastructure maintenance and vulnerabilities. Respondents noted that the highway-only PFN should take into account these interactions and impacts on the traveling public, especially if the highway-only PFN designation will increase truck traffic on those roadways.

In response, safety is the top priority for DOT and is a main goal of MAP–21's National Freight Policy. Although safety is not an express goal or factor in the designation of the highway-only PFN, each State's Strategic Highway Safety Plan (SHSP) affords a comprehensive approach and in-depth analysis for truck safety. The SHSPs are statewide, coordinated safety plans that provide a framework for reducing highway fatalities and serious injuries on all public roads. An SHSP identifies a State's key safety needs and guides investment decisions toward strategies and countermeasure with the most potential to save lives and prevent injuries. States are required to develop, implement, evaluate, and update an SHSP that identifies and analyzes highway safety problems and opportunities on all public roads.

Section 1118(b)(3) of MAP–21 requires that State Freight Plans include a description of how the plan will improve the ability of the State to meet the national freight goals established under section 167 of title 23, U.S.C., which include safety, and consideration of innovative technologies and operational strategies to improve the safety of freight movement. Sections 1118(b)(5) and (6) of MAP–21 also require consideration of routes projected to substantially deteriorate due to heavy vehicles and of areas of reduced mobility such as bottlenecks. The interim guidance for developing State Freight Plans pursuant to MAP–21 includes numerous safety elements.

There are data sources available to help States and MPOs measure these aspects of truck safety. The FHWA will work with our partners to ensure truck safety is considered and analyzed as appropriate in the SHSPs, as well as in State Freight Plans. The FHWA believes it is important to identify critical infrastructure through a multimodal freight network and to continue working with our partners and stakeholders to encourage actions to improve truck safety for these nationally significant areas and across the Nation's roadways.

Environmental and Greenhouse Gas Emissions Considerations

Respondents noted that the highway-only PFN designation does not incorporate environmental considerations, including greenhouse gas reduction and public health. More specifically, in the description of the methods and data sources used, no data sources incorporating environmental data were used. Comments noted this could be a critical element that would validate the designations and ensure that limited funding also provides environmental and public health benefits. Comments noted that the network should directly establish environmental and public health criteria (*e.g.,* emission reduction benefits) that are used in the designation process and later used in assessment of projects receiving funding, priority, or other benefits. Comments also noted that including environmental criteria provides additional contextual data to the network for understanding implications of a proposed project or identifying alternatives when viewed as a map overlay or other analysis.

In response, FHWA acknowledges the importance of understanding and mitigating the negative effects of freight on the environment and on communities. Freight projects, like other transportation projects, should consider and address environmental justice and access, air quality, water quality, and noise pollution, for example. With respect to mapping a freight network to reflect these aspects, however, the NFN and highway-only PFN requirements do not include factors relating to the environment or public health. The MAP–21 directed the Department to designate ''not more than 27,000 centerline miles of existing roadway that are most critical for the movement of freight'' in an NFN that is focused on ''improved system performance for efficient movement of freight.'' Further, national-level environmental data is limited in being able to offer a comprehensive assessment of these issues. In order to meet the various Federal requirements and advance human and environmental protection, the FHWA believes it is important to first identify the critical infrastructure in a multimodal freight network and then work with our partners and stakeholders to protect the environment and public health.

Designation of Private Roads and Rail Lines

Several respondents discussed the inclusion of private roads and rail lines, with many calling for the incorporation of private rail systems in a multimodal PFN. However, respondents representing railroads expressed concern that there is no information as to how a designation of a facility as part of the highway-only PFN will be used in the future. As discussed more generally in the previous section on ''NFN Use by Freight Stakeholders in the Future,'' commenters urged DOT to define the highway-only PFN's purpose before determining whether to include private infrastructure on the highway-only PFN or the NFN. Railroad stakeholders were concerned that Congress would establish minimum investment requirements or restrict future uses of the rail infrastructure. They questioned whether designation of private rail facilities would have consequences for funding decisions for these facilities, impact the ability to shift infrastructure funding to non-designated facilities, or result in freight user fees.

In response, FHWA acknowledges there are potential challenges related to designating private infrastructure as part of a highway-only PFN or NFN. However, because the Nation's multimodal freight system is comprised of both public and private infrastructure and the interdependencies, redundancies, and efficiencies of this entire network is relevant to understanding freight movement, it would be very beneficial to national and regional planning to include both types in a multimodal freight network. This is why we are concurrently and simultaneously releasing the draft Nation Freight Strategic Plan. The FHWA will continue to consider the implications of designating private and non-Federal infrastructure as they relate to the goals, objectives, and a future purpose of an MFN.

Intermodal Connectors

Some respondents supported incorporating all intermodal connections, arguing that this was imperative in building a seamless highway-only PFN. Respondents also highlighted the importance of having an updated listing of NHS freight intermodal connectors on the highway-only PFN map. Respondents recommended that intermodal connectors, specifically if they are adjacent to a trade gateway, major industrial, distribution and consumption area, seaport, river terminal or designated freight corridor, be prioritized for inclusion in the final highway-only PFN. Specific comments requested the inclusion of marine highways and urban intermodal connectors. Respondents also supported establishing a formal process for designating critical urban and rural freight routes that include first and last miles and/or intermodal connectors.

Comments touched on the need to include in the highway-only PFN more than just the intermodal connectors occurring in population centers of 200,000 or more. While the majority of commenters understood why FHWA chose to use the metric of AADTT to identify which segments of the NHS would appear on the highway-only PFN, there was confusion about why AADTT was not also used to measure and select intermodal connectors. Commenters were concerned with the fact that data sources used to analyze the intermodal connectors are incomplete. The respondents strongly recommended that FHWA consult with State DOTs, which, by working with their regional and local partners could assist the Federal Government in identifying routes that will ensure network connectivity to nationally significant intermodal facilities.

In response, FHWA agrees that NHS intermodal connectors are vital elements of the NFN. If the highway-only PFN was not mileage-constrained at 27,000 miles, priority consideration would be given to including all relevant urban and non-urban NHS freight intermodal connectors (these are included in the 41,518 mile comprehensive network). To adhere to the mileage cap, FHWA excluded those not meeting the AADTT threshold from the highway-only PFN. Regarding data, FHWA's listing of NHS intermodal connectors is current. However, FHWA does not have comprehensive data on the conditions and performance of each NHS intermodal connector. The FHWA supports efforts by infrastructure owners to collect comprehensive data on these facilities and update it on a frequent basis to help measure the performance of these connectors. The FHWA is conducting a research study to assess the conditions and performance of a representative sample of intermodal connectors. This information will assist the agency, its partners, and infrastructure owners in better assessing the current use of freight intermodal connectors, freight connector condition and performance, and in identifying connector impediments and solutions to allocate resources for the efficient flow of goods.

Military Bases/Facilities

Respondents requested that FHWA add strategic military bases to the origins and destinations of freight movements to be considered in the highway-only PFN designation. Comments indicated this would help provide for logistics that support a strong national defense. Respondents sought inclusion of U.S. Military Power

Projection Platform locations, as well as seaports and airports, because of their importance to national defense and their role as centers of significant regional economic activity. Respondents mentioned that the U.S. Army and U.S. Marine Corps have a list of power projection platforms, officially designated seaports of embarkation, and aerial ports of embarkation, that should be considered for the designation of these facilities. Respondents also noted that the Department of Defense (DOD) and the U.S. Maritime Administration have designated certain commercial seaports as ''Strategic Ports'' as part of the National Ports Readiness Network, because of the significant role they play in supporting port readiness, emergency operations, and cargo throughput capacity for global projection of our Armed Forces. Respondents supported FHWA's focus on the efficiency of freight movement in the highway-only PFN and believe that a benefit to freight movement in general will be a benefit to DOD cargo movement.

In response, FHWA acknowledges the importance of a variety of modes and types of facilities for the efficient movement of freight for the U.S. Armed Forces. The FHWA believes there are various national highway systems that have already been designated to meet the specific needs of the military and transportation of equipment and supplies. These systems include the U.S. Interstate Highway System, which was in part based on roads necessary for national defense, and the Strategic Highway Network (STRAHNET). The STRAHNET and the Strategic Rail Corridor Network were established as critical to DOD domestic operations, such as emergency mobilization and peacetime movement of heavy armor, fuel, ammunition, repair parts, food, and other commodities to support U.S. military operations. As a result, FHWA does not think access to every military base or strategic port needs to be part of the highway-only PFN. The DOT will consider how best to include them on the MFN. The FHWA has identified a number of intermodal connectors under the 41,000 comprehensive networks that connect to military bases/facilities and will include these NHS freight intermodal connectors in future designations of the highway-only PFN if the mileage cap is increased. In addition, the entire mileage of the final highway-only PFN is part of STRAHNET.

National Freight Advisory Committee (NFAC)

The Secretary of Transportation established the National Freight Advisory Committee (NFAC) in 2013 to provide advice and recommendations on matters related to freight transportation in the United States. This Committee is composed of representatives from the public and private sector, local and State governments, labor unions, safety organizations, transportation organizations, freight shipping companies, and other freight stakeholder organizations. The NFAC undertook an extensive review of the draft designation of the highway-only PFN and provided the comments and recommendations, which can be found here: *https://www.transportation.gov/sites/dot.gov/files/docs/NFAC%20Joint%20Comment%20to%20Hwy%20PFN%20-Initial%20Comments%20Consolidated.pdf.*

The NFAC stated that it did not endorse the proposed highway-only PFN and directed its comments to both Congress and DOT. Its primary concerns were related to the size and nature of the 27,000 centerline miles limitation and the need for a multimodal freight network. The NFAC felt the draft highway-only PFN lacked critical elements of first and last mile connectors, especially in urban areas, as well as port connectors and North American gateway connections. The Committee preferred a hub- and corridor-based, multimodal approach for designation and opposed the statutory imposition of a mileage threshold. They urged DOT to proceed with a multimodal network, engaging the public and including an urban designation process. They supported the use of AADTT in a highway-only PFN. In the absence of a revised highway-only PFN, they preferred that funding be prioritized to solve truck congestion on existing freight corridors and gateways.

Regarding the lack of a stated purpose for the PFN, the NFAC felt DOT should develop goals in coordination with a variety of public and private sector stakeholders and use these goals to inform the development of the Conditions and Performance Report and the National Freight Strategic Plan. They felt that these goals must address the intended use of the highway-only PFN, whether it should have a role in prioritizing needs or justifying investment, and why it did not give full consideration to first or last mile segments. According to the NFAC, the lack of goals impedes the ability to have a national investment strategy.

When highway-only PFN goals are established, the NFAC believes flexible investment strategies should be afforded to the States and private railroads should retain their autonomy to manage their infrastructure. They called on Congress in the next reauthorization to provide for a comprehensive data program and for access to private sector data and other sources to support freight planning. They cited the value of State Freight Plans and State Freight Advisory Committees in informing national planning and sought to make these mandatory. There was strong support for local and State leadership in designating urban freight networks. They called on DOT to consider and incorporate future trends in goods movement, and to re-designate or modify more frequently than the 10-year cycle. The NFAC urged the creation of dedicated funding from additional revenue sources to support both planning and to incentivize investment in projects.

The NFAC further recommended that DOT consider where freight should be encouraged to move as opposed to only reflecting current movements. The Committee requested the location of structurally deficient bridges or ''freight restricted bridges'' be considered for the highway-only PFN. They also submitted the following list of routes they felt was missing from the highway-only PFN:

- Primary high-traffic connectors between freight terminals and Interstate highways;
- Intermodal connectors, connections to logistics centers and manufacturing centers (freight origin and destination points);
- Highway segments that provide unique through-routes for 53-foot national standard tractor-trailers;
- Metropolitan components and urban connectors;
- Critical highways based on where activity is happening, not just those on the Interstate system (non-Interstate networks);
- Farm-to-market routes;
- Waterways;
- International gateways such as highway border crossings, airports, seaports, Great Lakes ports and river terminals that provide significant freight movement; and
- Interstate crossings connecting urban areas with national manufacturers and distribution centers in different states.

Highway-Only PFN Data and Methodology

Section 167(c) of title 23, U.S.C., directed the Secretary to establish a NFN to assist States in strategically directing resources toward improved system performance for efficient movement of freight on the highway portion of the Nation's freight transportation system. Consistent with the national freight policy in MAP–21, DOT's goal was to designate a highway-only PFN that would improve system performance, maximize freight efficiency, and be effectively integrated with the entire freight transportation system, including non-highway modes of freight transport. The FHWA explored the development of a NFN to provide connectivity between and throughout the three elements that comprise the NFN (highway-only PFN, remainder of the Interstate System, and CRFC).

Data Used for the Designation of the Highway-Only Primary Freight Network

In undertaking the highway-only PFN designation, FHWA developed multiple scenarios to identify a network that represents the most critical highway portions of the United States freight system. The highway-only PFN was informed by measurable and objective national data. In performing the analysis that led to the development of the highway-only PFN, FHWA considered the following criteria and data sources, which are further described at the listed Web locations:

Factor	Data source	Parameters
Origins/d destinations of freight.	FAF 3.4 *http://faf.ornl.gov/fafweb/Extraction0.aspx*	Connect top origins/destinations.
Freight tonnage and value by highways.	FAF 3.4 *http://faf.ornl.gov/fafweb/Extraction0.aspx*	Include top routes by weight of freight transported; Include top routes by value of commodity transported.
Percentage of AADTT on principal arterials.	HPMS 2010 AADTT *http://www.fhwa.dot.gov/policyinformation/hpms.cfm*.	Include top routes by percentage of AADTT on principal arterials.
AADTT on principal arterials	HPMS 2010 AADTT *http://www.fhwa.dot.gov/policyinformation/hpms.cfm*.	Include top routes by AADTT on principal arterials.
Land and maritime ports of entry.	USACE U.S. Army Corps, Navigation Data Center, special request, October 2012 via BTS.	Connect top seaports and river terminals ranked by weight and values.
	MARAD *http://www.marad.dot.gov/documents/Container_by_US_Customs_Ports.xls*.	Connect top seaports and river terminals ranked by number of 20-foot equivalent unit containers (TEUs).
	BTS Transborder data *http://www.bts.gov/programs/international/transborder/TBDR_QuickSearch.html*.	Connect top land ports for both weight and values.
Access to energy exploration, development, installation or production areas.	EIA (U.S. Energy Information Administration) *http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/maps/maps.htm#geodata*.	Include access to coal basins, top coal mines, coalbed methane fields, natural gas production locations, gas and oil exploration areas.
	Pennwell Mapsearch data via Pipeline and Hazardous Materials Safety Administration (PHMSA) *http://www.mapsearch.com*.	Include access to oil refineries and distribution centers.
	Pennwell Mapsearch data via Pipeline and Hazardous Materials Safety Administration (PHMSA) *http://www.mapsearch.com*.	Include access to pipeline terminal locations.
	Pennwell Mapsearch data via Pipeline and Hazardous Materials Safety Administration (PHMSA) *http://www.mapsearch.com*.	Include access to biodiesel and ethanol plants.
Population centers	2010 Census *http://www.census.gov/cgibin/geo/shapefiles2010/main*.	Connect top urbanized areas; Utilize Census Urbanized Area Boundary for geographic areas.
Network connectivity	FAF 3.4 *http://faf.ornl.gov/fafweb/Extraction0.aspx*	Reduce gaps by connecting highway-only PFN segments to each other or to the Interstate System, or begin/end at access point.

Methodology Used for the Designation of the Highway-Only Primary Freight Network

The FHWA developed the following methodology with the intention of generating a network that could include as many of the MAP–21 criteria as practicable. The FHWA undertook extensive research and numerous approaches to better understand and model the criteria. This research informed our finding that compliance with the mileage cap yields a network that does not sufficiently accommodate the full set of criteria. In order to comply with the mileage cap while still accommodating the statutory criteria, FHWA developed a methodology that prioritized the application of the criteria and set thresholds within the data sets. The FHWA used the following methodology to develop the highway-only PFN:

(1) Used the FAF and HPMS data sets to generate the top 20,000 miles of road segments that qualified in at least two of the following four factors: Value of freight moved by highway; tonnage of freight moved by highway; AADTT on principal arterials; and percentage of AADTT in the annual average daily traffic on principal arterials.

(2) Analyzed the segments identified in Step 1 and gaps between segments for network connectivity. Created the network by connecting segments if the gap between segments was equal to or less than 440 miles (440 miles being the distance a truck could reasonably travel in 1 day). Eliminated a segment if it was less than one-tenth of the length of the nearest qualifying segment on the highway-only PFN.

(3) Identified land ports of entry with truck traffic higher than 75,000 trucks per year. Connected these land ports of entry to the network created in Steps 1 and 2.

(4) Identified the NHS Freight Intermodal Connectors within urban areas with a population of 200,000 or more.[3] The NHS Freight Intermodal Connectors included any connectors categorized as connecting to a freight rail terminal, port, river terminal, or pipeline. In addition, these NHS Freight Intermodal Connectors included routes to the top 50 airports by landed weight of all cargo operations (representing 89 percent of the landed weight of all cargo operations in the U.S.). Connected the NHS Freight Intermodal Connectors back to the network created in Steps 1 and 2 along the route with the highest AADTT using HPMS data.

(5) Identified road segments within urban areas with a population of

[3] The Census defined urban areas (UZAs) were used rather than the adjusted UZAs since these were not available at the time of the analysis.

200,000 or more that have an AADTT of 8,500 trucks/day or more.[4] Connected segments to the network established in Steps 1 and 2 if they were equal to or greater than one-tenth of the length of the nearest qualifying segment on the highway-only PFN. Removed segments not meeting this rule as they were more likely to represent discrete local truck movement unrelated to the national system.

(6) Analyzed the network to determine the relationship to population centers, origins and destinations, ports, river terminals, airports, and rail yards and added minor network connectivity adjustments.

(7) Analyzed the road systems in Alaska, Hawaii, and Puerto Rico using HPMS data. These routes would not otherwise qualify under a connected network model but play a critical role in the movement of products from the agriculture and energy sectors, as well as international import/export functions for their States and urban areas and added roads connecting key seaports to population centers.

(8) Analyzed the network to determine the relationship to energy exploration, development, installation, or production areas. Since the data points for the energy sector are scattered around the United States, often in rural areas, and because some of the related freight may move by barge or other maritime vessel, rail, or even pipeline, FHWA did not presume a truck freight correlation.

(9) Steps 1 through 8 resulted in a network of 41,518 centerline miles, including 37,436 centerline miles of Interstate and 4,082 centerline miles of non-Interstate roads.[5] In order to obtain the 27,000 centerline miles, FHWA identified those segments with the highest AADTT. These road segments represented on the final highway-only PFN map comprise 26,966 miles of centerline roads.

Final Highway-Only Primary Freight Network Map

The FHWA has posted the details of the final initial highway-only PFN, including the 26,966-mile highway-only PFN map, State maps, and lists of designated routes and tables of mileage by State at: *http://ops.fhwa.dot.gov/freight/infrastructure/nfn/index.htm.*

This final highway-only PFN, which is unchanged from the draft released in November 2013, attempts to reflect the many criteria established in MAP–21 while also complying with the mileage cap. As a result, the highway-only PFN results in an unconnected network with major gaps in the system, including components of the global and domestic supply chains. Therefore, DOT is concurrently and simultaneously developing an MFN as part of the National Freight Strategic Plan that better represents the complex multimodal freight system in the U.S. and has proposed the GROW AMERICA legislation that is responsive to the many public comments outlined in this notice.

Authority: 23 U.S.C. 167; 49 CFR 1.85.

Issued on: October 15, 2015.

Gregory G. Nadeau,

FHWA Administrator.

[FR Doc. 2015–27036 Filed 10–22–15; 8:45 am]

BILLING CODE 4910–22–P

[4] Ibid.

[5] Readers should note the 2011 HPMS database and the current FAF database differ in the delineation and exact geo-location of the NHS system. This may result in plus/minus 1–2% variation on the total mileage because the mileage is based on the geospatial network and actual mileage reported by States may vary due to vertical and horizontal curves that are not always accurate in GIS databases. The DOT will look to integrate the 2011 HPMS database with the FAF database to reduce variation in future iterations.

DEPARTMENT OF TRANSPORTATION

Federal Highway Administration

Buy America Waiver Notification

AGENCY: Federal Highway Administration (FHWA), DOT.

ACTION: Notice.

SUMMARY: This notice provides information regarding FHWA's finding that a Buy America waiver is appropriate for the use of non-domestic fabrication of cable mesh for 8′–0″ high oxidized stainless steel cable net safety fence on Interstate 5, MP 28.7 in San Diego, California.

DATES: The effective date of the waiver is October 26, 2015.

FOR FURTHER INFORMATION CONTACT: For questions about this notice, please contact Mr. Gerald Yakowenko, FHWA Office of Program Administration, (202) 366–1562, or via email at *gerald.yakowenko@dot.gov.* For legal questions, please contact Mr. Jomar Maldonado, FHWA Office of the Chief Counsel, (202) 366–1373, or via email at *Jomar.Maldonado@dot.gov.* Office hours for the FHWA are from 8:00 a.m. to 4:30 p.m., E.T., Monday through Friday, except Federal holidays.

SUPPLEMENTARY INFORMATION:

Electronic Access

An electronic copy of this document may be downloaded from the **Federal Register**'s home page at: *http://www.archives.gov* and the Government Printing Office's database at: *http://www.access.gpo.gov/nara.*

Background

The FHWA's Buy America policy in 23 CFR 635.410 requires a domestic manufacturing process for any steel or iron products (including protective coatings) that are permanently incorporated in a Federal-aid construction project. The regulation also provides for a waiver of the Buy America requirements when the application would be inconsistent with the public interest or when satisfactory quality domestic steel and iron products are not sufficiently available. This notice provides information regarding FHWA's finding that a Buy America waiver is appropriate for use of non-domestic fabrication process to convert the stainless steel products into safety cable mesh. The stainless steel product for the cable mesh is produced domestically in the United States. However, there is no domestic manufacturer capable of fabricating the stainless steel products into safety cable mesh.

In accordance with Division K, section 122 of the ''Consolidated and Further Continuing Appropriations Act, 2015'' (Pub. L. 113–235), FHWA published a notice of intent to issue a waiver on its Web site (*http://www.fhwa.dot.gov/construction/contracts/waivers.cfm?id=113*) on September 9th. The FHWA received no comments in response to the publication. Based on all the information available to the agency, FHWA concludes that there are no domestic manufacturers capable of fabricating the safety cable mesh.

In accordance with the provisions of section 117 of the SAFETEA–LU Technical Corrections Act of 2008 (Pub. L. 110–244, 122 Stat. 1572), FHWA is providing this notice as its finding that a waiver of Buy America requirements is appropriate. The FHWA invites public comment on this finding for an additional 15 days following the effective date of the finding. Comments may be submitted to FHWA's Web site via the link provided to the waiver page noted above.

Authority: 23 U.S.C. 313; Pub. L. 110–161, 23 CFR 635.410.

Issued on: October 16, 2015.

Gregory G. Nadeau,

Administrator, Federal Highway Administration.

[FR Doc. 2015–27027 Filed 10–22–15; 8:45 am]

BILLING CODE 4910–22–P

DEPARTMENT OF TRANSPORTATION

Surface Transportation Board

[Docket No. FD 35962]

Terminal Railroad Association of St. Louis—Trackage Rights Exemption—Norfolk Southern Railway Company

Norfolk Southern Railway Company (NSR), pursuant to a written trackage rights agreement dated July 31, 2015, has agreed to grant limited local trackage rights to the Terminal Railroad Association of St. Louis (TRRA) over approximately 0.49 miles of rail line in St. Louis, Mo. (the Line). Specifically, TRRA will acquire trackage rights between TRRA's connection with NSR at approximately North Market Street, St. Louis, Mo., and the Kiesel Facility at approximately Dock Street, St. Louis, Mo.

TRRA may consummate its acquisition on or after November 7, 2015, the effective date of the exemption (30 days after the verified notice of exemption was filed).

TRRA states that NSR, who currently operates over TRRA via trackage rights to access the Line and serve the Kiesel Facility, intends to discontinue a nearby two-mile segment of trackage. According to TRRA, granting TRRA limited local trackage rights over the Line for the sole purpose of serving the Kiesel Facility (the only active shipper accessible via the Line) will allow NSR and TRRA to operate more efficiently in this area after NSR's nearby discontinuance while also preserving rail service to an existing customer. TRRA will assume maintenance of the Line until NSR decides to resume active operations over the Line.

As a condition to this exemption, any employees affected by the trackage rights will be protected by the conditions imposed in *Norfolk & Western Railway—Trackage Rights—Burlington Northern, Inc.,* 354 I.C.C. 605 (1978), as modified in *Mendocino Coast Railway—Lease & Operate—California Western Railroad,* 360 I.C.C. 653 (1980).

This notice is filed under 49 CFR 1180.2(d)(7). If the notice contains false or misleading information, the exemption is void ab initio. Petitions to revoke the exemption under 49 U.S.C. 10502(d) may be filed at any time. The filing of a petition to revoke will not automatically stay the effectiveness of the exemption. Petitions for stay must be filed by October 30, 2015 (at least seven days before the exemption becomes effective).

An original and 10 copies of all pleadings, referring to Docket No. FD 35962, must be filed with the Surface Transportation Board, 395 E Street SW., Washington, DC 20423–0001. In addition, a copy of each pleading must be served on Asim S. Raza, Terminal Railroad Association of St. Louis, 415 S. 18th Street, Suite 200, St. Louis, MO 63103.

Board decisions and notices are available on our Web site at *WWW.STB.DOT.GOV.*

Decided: October 20, 2015.

By the Board, Rachel D. Campbell, Director, Office of Proceedings.

Kenyatta Clay,

Clearance Clerk.

[FR Doc. 2015–26987 Filed 10–22–15; 8:45 am]

BILLING CODE 4915–01–P

DEPARTMENT OF TRANSPORTATION

Surface Transportation Board

[Docket No. FD 35966]

Martin Marietta Materials, Inc.—Acquisition of Control Exemption—Rock & Rail, Inc.

Martin Marietta Materials, Inc. (MMM), a noncarrier, has filed a verified notice of exemption under 49 CFR 1180.2(d)(2) to acquire control of Rock & Rail, Inc. (RRI), a Class III rail carrier.

According to MMM, it currently controls Alamo North Texas Railroad (ANT),[1] a Class III rail carrier, which has lines in Wise County, Tex., and Alamo Gulf Coast Railroad (AGC), a Class III rail carrier, which has lines in Bexar County, Tex. MMM states that RRI has lines in Pueblo and Canon City, Colo., and that the proposed transaction would not connect ANT, AGC, or RRI. MMM and RRI have signed a letter of intent [2] by which MMM will acquire indirect ownership of 100% of the stock of RRI. The transaction is scheduled to be consummated on or after November 8, 2015, the effective date of the exemption.

MMM states that: (i) The railroads do not connect with each other or any railroad in their corporate family; (ii) the proposed transaction is not part of a series of anticipated transactions that would connect the railroads with each other or any railroad in their corporate family; and (iii) the transaction does not involve a Class I carrier. Therefore, the transaction is exempt from the prior approval of requirements of 49 U.S.C. 11323. *See* 49 CFR 1180.2(d)(2).

Under 49 U.S.C. 10502(g), the Board may not use its exemption authority to relieve a rail carrier of its statutory obligation to protect the interests of its employees. Section 11326(c), however, does not provide for the labor protection for transactions under §§ 11324 and 11325 that involve only Class III rail carriers. Because this transaction involves Class III rail carriers only, the Board, under the statute, may not impose labor protective conditions for this transaction.

If the verified notice contains false or misleading information, the exemption is void ab initio. Petitions to revoke the exemption under 49 U.S.C. 10502(d) may be filed at any time. The filing of a petition to revoke will not automatically stay the transaction. Petitions to stay must be filed no later than October 30, 2015 (at least seven days before the exemption becomes effective).

An original and ten copies of all pleadings referring to Docket No. FD 35966, must be filed with the Surface Transportation Board, 395 E Street SW., Washington, DC 20423–0001. In addition, a copy of each pleading must be served on William A. Mullins, Baker & Miller PLLC, 2401 Pennsylvania Ave. NW., Suite 300, Washington, DC 20037.

Board decisions and notices are available on our Web site at *WWW.STB.DOT.GOV.*

Decided: October 20, 2015.

By the Board, Rachel D. Campbell, Director, Office of Proceedings.

Brendetta S. Jones,

Clearance Clerk.

[FR Doc. 2015–27052 Filed 10–22–15; 8:45 am]

BILLING CODE 4915–01–P

[1] *See Martin Marietta Materials, Inc.—Continuance in Control Exemption—Alamo N. Tex. R.R.,* FD 34266 (STB served Dec. 13, 2002).

[2] An unredacted copy of the letter of intent was filed concurrently under seal, along with a motion for protective order pursuant to 49 CFR 1104.14(b). That motion will be addressed in a separate decision.

DEPARTMENT OF TRANSPORTATION

Surface Transportation Board

[Docket No. AB 1112X]

Caldwell Railroad Commission—Abandonment Exemption—in Caldwell County, NC

Caldwell Railroad Commission (CRC) has filed an amended verified notice of exemption under 49 CFR pt. 1152 subpart F—*Exempt Abandonments* to abandon an approximately 3.91-mile rail segment extending between milepost 108.79 and milepost 112.7 in Caldwell County, N.C. (the Line).[1] The

[1] CRC previously filed a verified notice of exemption that was dismissed as moot, because CRC's predecessor had obtained a 49 U.S.C. Subtitle

Continued

Line traverses United States Postal Service Zip Code 28645.

CRC has certified that: (1) No freight traffic has moved over the Line for at least two years; (2) any overhead traffic over the Line can and has been rerouted; (3) no formal complaint filed by a user of rail service on the Line (or by a state or local government entity acting on behalf of such user) regarding cessation of service over the Line is either pending with the Surface Transportation Board (Board) or with any U.S. District Court or has been decided in favor of complainant within the two-year period; and (4) the requirements at 49 CFR 1105.7(c) (environmental report), 49 CFR 1105.11 (transmittal letter), 49 CFR 1105.12 (newspaper publication), and 49 CFR 1152.50(d)(1) (notice to governmental agencies) have been met.

As a condition to this exemption, any employee adversely affected by the abandonment shall be protected under *Oregon Short Line Railroad—Abandonment Portion Goshen Branch Between Firth & Ammon, in Bingham & Bonneville Counties, Idaho,* 360 I.C.C. 91 (1979). To address whether this condition adequately protects affected employees, a petition for partial revocation under 49 U.S.C. 10502(d) must be filed.

Provided no formal expression of intent to file an offer of financial assistance (OFA) has been received, this exemption will be effective on November 24, 2015, unless stayed pending reconsideration. Petitions to stay that do not involve environmental issues,[2] formal expressions of intent to file an OFA under 49 CFR 1152.27(c)(2),[3] and interim trail use/rail banking requests under 49 CFR 1152.29 must be filed by November 2, 2015. Petitions to reopen or requests for public use[4] conditions under 49 CFR 1152.28 must be filed by November 12, 2015, with the Surface Transportation Board, 395 E Street SW., Washington, DC 20423–0001.

A copy of any petition filed with the Board should be sent to CRC's representative: David H. Coburn, Steptoe & Johnson LLP, 1330 Connecticut Ave. NW., Washington, DC 20036.

If the verified notice contains false or misleading information, the exemption is void ab initio.

CRC has filed environmental and historic reports that address the effects, if any, of the abandonment on the environment and historic resources. OEA will issue an environmental assessment (EA) by October 30, 2015. Interested persons may obtain a copy of the EA by writing to OEA (Room 1100, Surface Transportation Board, Washington, DC 20423–0001) or by calling OEA at (202) 245–0305. Assistance for the hearing impaired is available through the Federal Information Relay Service at (800) 877–8339. Comments on environmental and historic preservation matters must be filed within 15 days after the EA becomes available to the public.

Environmental, historic preservation, public use, or interim trail use/rail banking conditions will be imposed, where appropriate, in a subsequent decision.

Pursuant to the provisions of 49 CFR 1152.29(e)(2), CRC shall file a notice of consummation with the Board to signify that it has exercised the authority granted and fully abandoned the Line. If consummation has not been effected by CRC's filing of a notice of consummation by October 23, 2016, and there are no legal or regulatory barriers to consummation, the authority to abandon will automatically expire.

Board decisions and notices are available on our Web site at *WWW.STB.DOT.GOV.*

Decided: October 20, 2015.

By the Board, Rachel D. Campbell, Director, Office of Proceedings.

Kenyatta Clay,

Clearance Clerk.

[FR Doc. 2015–27142 Filed 10–22–15; 8:45 am]

BILLING CODE 4915–01–P

IV exemption over the relevant portion of the Line, which encompassed authority to abandon the Line. *Caldwell R.R. Comm'n—Aban. Exemption—in Caldwell Cty., N.C.,* AB 1112X (STB served May 22, 2015). CRC subsequently obtained a partial revocation of that Subtitle IV exemption, which allows CRC to pursue abandonment authority. *Caldwell R.R. Comm'n—Exemption from 49 U.S.C. Subtitle IV,* FD 32659 (Sub-No. 2) (STB served Sept. 8, 2015).

[2] The Board will grant a stay if an informed decision on environmental issues (whether raised by a party or by the Board's Office of Environmental Analysis (OEA) in its independent investigation) cannot be made before the exemption's effective date. *See Exemption of Out-of-Serv. Rail Lines,* 5 I.C.C.2d 377 (1989). Any request for a stay should be filed as soon as possible so that the Board may take appropriate action before the exemption's effective date.

[3] Each OFA must be accompanied by the filing fee, which is currently set at $1,600. *See* 49 CFR 1002.2(f)(25).

[4] CRC states that the Line may be suitable for other public purposes or trail use, but may be subject to reversionary interests.

DEPARTMENT OF TRANSPORTATION

Office of the Secretary

[Docket No. DOT–OST–2015–0197]

Privacy Act of 1974; Department of Transportation, Office of the Secretary of Transportation; DOT/ALL–18, International Freight Data System (IFDS)

AGENCY: Office of the Departmental Chief Information Officer, Office of the Secretary of Transportation, DOT.

ACTION: Notice of retirement of one Privacy Act system of records.

SUMMARY: In accordance with the Privacy Act of 1974, the Department of Transportation (DOT) is giving notice that it will retire the following Privacy Act system of records: DOT/ALL 18, International Freight Data System (IFDS) (April 14, 2008, 73 FR 20084). The IFDS was never implemented by the DOT and the DOT will continue to rely upon the U.S. Customs and Border Protection's Automated Commercial Environment/International Trade Data System for its data needs.

DATES: This change will take effect upon publication.

FOR FURTHER INFORMATION CONTACT: For questions, please contact: Claire W. Barrett, Departmental Chief Privacy Officer, Privacy Office, Department of Transportation, Washington, DC 20590; *privacy@dot.gov;* or 202.527.3284.

SUPPLEMENTARY INFORMATION:

I. Background

Pursuant to the provisions of the Privacy Act of 1974, 5 U.S.C. 552a, and as part of its ongoing integration and management efforts, DOT is retiring the system of records notice, DOT/ALL 18 International Freight Data System (IFDS) (April 14, 2008, 73 FR 20084), which was intended to be an automated system that provided participating DOT Operating Administrations with international commercial information to perform their enforcement, statistical, analytical, modeling and policy responsibilities. The IFDS was never implemented by the DOT and the DOT will continue to rely upon DHS/CBP–001, Automated Commercial Environment/International Trade Data System (January 19, 2006, 71 FR 3109) for the collection and dissemination of international commercial information.

Eliminating the system of records notice DOT/ALL 18, International Freight Data System, will have no adverse impacts on individuals and will accurately characterize DOT Privacy Act record systems.

Claire W. Barrett,

Departmental Chief Privacy Officer.

[FR Doc. 2015–26366 Filed 10–22–15; 8:45 am]

BILLING CODE 4910–9X–P

DEPARTMENT OF TRANSPORTATION

Office of the Secretary

[Docket No. DOT–OST–2015–0160]

Privacy Act of 1974; Department of Transportation/ALL 8, Parking and Transit Benefit System

AGENCY: Privacy Office, Office of the Secretary of Transportation, DOT.

ACTION: Notice of Privacy Act system of records.

SUMMARY: In accordance with the Privacy Act of 1974, the U.S. Department of Transportation proposes to rename, update, and reissue the Department of Transportation system of records currently titled, ''Department of Transportation/ALL 8 Employee Transportation Facilitation System of Records.'' This system of records allows the Department of Transportation/Office of the Secretary to collect and maintain records on Department of Transportation employees who participate in the Department's transit, carpool/vanpool, bicycle and parking benefit program, employees of other Federal agencies for whom DOT administers a Federal carpool/vanpool, and/or parking and transit benefit program. It also allows the Federal Aviation Administration to collect and maintain records on behalf of its employees who participate in transit and parking benefit programs administered by the Federal Aviation Administration. In addition to non-substantive changes to simply the formatting and text of the previously published notice, we are revising this notice to reflect System Manager's address change, and clarify the routine uses of information in the system. This updated system will be renamed and included in the Department of Transportation's inventory of record systems and referred to as ''DOT/ALL 8—Parking and Transit Benefit System.''

DATES: Written comments should be submitted on or before November 23, 2015. The Department may publish an amended SORN in light of any comments received. This revised system will be effective November 23, 2015.

ADDRESSES: You may submit comments, identified by docket number DOT–OST–2015–0160 by any of the following methods:

- *Federal e-Rulemaking Portal: http://www.regulations.gov.* Follow the instructions for submitting comments.
- *Mail:* Docket Management Facility, U.S. Department of Transportation, 1200 New Jersey Ave. SE., West Building Ground Floor, Room W12–140, Washington, DC 20590–0001.
- *Hand Delivery or Courier:* West Building Ground Floor, Room W12–140, 1200 New Jersey Ave. SE., between 9 a.m. and 5 p.m. ET, Monday through Friday, except Federal Holidays.
- *Fax:* (202) 493–2251.

Instructions: You must include the agency name and docket number DOT–OST–2015–0160. All comments received will be posted without change to *http://www.regulations.gov,* including any personal information provided.

Privacy Act: Anyone is able to search the electronic form of all comments received in 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 January 17, 2008 (73 FR 3316–3317).

Docket: For access to the docket to read background documents or comments received, go to *http://www.regulations.gov* or to the street address listed above. Follow the online instructions for accessing the docket.

FOR FURTHER INFORMATION CONTACT: For questions, please contact: Claire W. Barrett, Departmental Chief Privacy Officer, Privacy Office, Department of Transportation, Washington, DC 20590; *privacy@dot.gov;* or (202) 527–3284.

SUPPLEMENTARY INFORMATION:

I. Background

The DOT/Office of the Secretary (OST) manages a Transportation Subsidy Program (TSP) and facilitates the distribution of public-transport fare media to DOT and other Federal Agency employees, to schedule distribution of the fare media, to maintain an inventory of fare media on hand, and to manage the fare media billing. DOT administers the TSP for its employees, and, also, for employees of other Federal agencies through Interagency Agreements between DOT and the employer-agency. Additionally, the Office of Transportation Services (TRANServe), within DOT's Office of the Assistant Secretary for Administration, manages the bicycle benefit program and the vehicle parking resources at the DOT South East Federal Center (SEFC) Headquarters Facility. Parking at the Headquarters Facility is allocated via the DOT Headquarters Parking Application (DOT HPA) reservation system. The Federal Aviation Administration (FAA) administers its own parking and transit benefit program for FAA employees in the Washington, DC area (transit and parking benefits for FAA field office employees are administered by OST).

In accordance with the Privacy Act of 1974, 5 U.S.C. 552a, the U.S. Department of Transportation (DOT)/Office of the Secretary of Transportation (OST) proposes to rename, update, and reissue the DOT system of records currently titled, ''DOT/ALL–8 Employee Transportation Facilitation.'' This system of records will be renamed ''DOT/ALL–8, Parking and Transit Benefit System.''

In addition, we are updating this system of records notice to reflect the change in the system manager's address resulting from DOT's move from its previous headquarters location at 400 7th Street SW., Washington, DC 20950, to its new location of 1200 New Jersey Ave. SE., Washington, DC 20590. We have also updated the system to provide greater detail about the categories of records collected and maintained, and include additional categories to reflect DOT's administration of the bicycle benefit program. Additionally, DOT will begin to collect the names of other riders in van pools (in addition to those individuals who are participating in the TSP). DOT will collect this information to aid in efforts to identify potential waste, fraud, and abuse. Finally, we are updating the routine uses to provide greater clarity and specificity to our routine uses of the information in this system. The current SORN generally describes the routine uses for this system in a narrative format. We wish to update this to provide great specificity about who we disclose these records to and the purposes for which we make the disclosure. We believe that these changes do not substantively alter the current routine uses, but merely provide greater transparency.

This updated system will be included in DOT's inventory of record systems.

II. Privacy Act

The Privacy Act (5 U.S.C. 552a) governs the means by which the Federal Government collects, maintains, and uses personally identifiable information (PII) in a System of Records. A ''System of Records'' is a group of any records under the control of a Federal agency from which information about individuals is retrieved by name or other personal identifier. The Privacy

Act requires each agency to publish in the **Federal Register** a System of Records notice (SORN) identifying and describing each System of Records the agency maintains, including the purposes for which the agency uses PII in the system, the routine uses for which the agency discloses such information outside the agency, and how individuals to whom a Privacy Act record pertains can exercise their rights under the Privacy Act (*e.g.,* to determine if the system contains information about them and to contest inaccurate information).

In accordance with 5 U.S.C. 552a(r), DOT has provided a report of this system of records to the Office of Management and Budget and to Congress.

SYSTEM OF RECORDS:

DOT/ALL 8

SYSTEM NAME:

Parking and Transit Benefit System.

SECURITY CLASSIFICATION:

Unclassified, sensitive.

SYSTEM LOCATION:

Department of Transportation, Office of the Secretary, Parking and Transit Benefit Office, 1200 New Jersey Ave. SE., Washington, DC 20950; Federal Aviation Administration, Transit Benefit Office, 800 Independence Ave. SW., Washington, DC 20591.

CATEGORIES OF INDIVIDUALS COVERED BY THE SYSTEM:

Federal employees' who receive transit or bicycle subsidies, who hold parking permits, or are members of carpools and vanpools; applicants for ridesharing information; recipients of match letters for carpooling; applicants for transit subsidies issued by DOT; vanpool operators.

CATEGORIES OF RECORDS IN THE SYSTEM:

Categories of records in the system include:

The following information about recipients of bicycle or transit subsidies; holders of parking permits, participants in carpools or vanpools; or applicants for ridesharing information:

Full name

Employee identification number (which, depending on the employer, may be the employee's social security number, the last four digits of the employee's social security number, or some other identification number used by a Federal agency as an employee's identification number)

Employer name

Employer's address

Home address

Business telephone number

Employee's work email address

Transit provider name, address, and mode of transportation used for commute

Location employee commutes to/from

Number of days employee commutes per month

Subsidy amount

System identifier (number randomly generated by DOT's system and assigned to files)

Transit card number

Parking permit number

License plate number and issuing state

Parking permit holder payment status (paid/unpaid) and payment information

Bicycle benefit recipients' itemized lists of expenditures eligible for bicycle benefit

The following information may be collected and maintained about van pool operators:

Full name

Business address

First and last name of individuals who use the van pool

AUTHORITY FOR MAINTENANCE OF THE SYSTEM:

5 U.S.C. 7905; 26 U.S.C. 132; 26 CFR 132f; Executive Order 13150 (April 21, 2001)

PURPOSE:

The purpose of this system is to collect and maintain information about Federal employees' and vanpool operators who participate in carpool/vanpool, transit, parking, or bicycle benefit programs in connection with the DOT's administration of these programs for its and other Federal agency employees.

ROUTINE USES OF RECORDS MAINTAINED IN THE SYSTEM, INCLUDING CATEGORIES OF USERS AND THE PURPOSES OF SUCH USES:

In addition to those disclosures generally permitted under 5 U.S.C. 552a(b) of the Privacy Act, all or a portion of the records or information contained in this system may be disclosed outside DOT as a routine use pursuant to 5 U.S.C. 552a(b)(3) as follows:

1. To the Federal agency for whom DOT administers a transit benefit program, for purposes of verifying that agency's employee's participation in the program, and auditing and verifying disbursements;

2. To the operators of transit systems or vanpools for purposes of activating, distributing, and verifying benefits;

3. To the entity that manages the parking facility at the DOT Headquarters in Southeast Washington, DC, information about individuals who have delinquent daily parking fees for purpose of ensuring eligibility of daily parkers;

4. To the Department of Treasury's approved Financial Agent for purposes of distributing transit benefits;

5. To consumer reporting agencies (collecting on behalf of the United States Government) as defined in the Fair Credit Reporting Act (15 U.S.C. 1681a(f)) or the Federal Claims Collection Act of 1982 (31 U.S.C. 3701(a)(3));

6. See ''Prefatory Statement of General Routine Uses'' (available at *http://www.dot.gov/privacy/privacyactnotices*). Other possible routine uses of the information, applicable to all DOT Privacy Act systems of records, are published in the **Federal Register** at 75 FR 82132, December 29, 2010, and 77 FR 42796, July 20, 2012, under ''Prefatory Statement of General Routine Uses'' (available at *http://www.dot.gov/privacy/privacyactnotices*).

DISCLOSURES TO CONSUMER REPORTING AGENCIES:

Disclosures may be made from this system to consumer reporting agencies (collecting on behalf of the United States Government) as defined in the Fair Credit Reporting Act (15 U.S.C. 1681a(f)) or the Federal Claims Collection Act of 1982 (31 U.S.C. 3701(a)(3)).

POLICIES AND PRACTICES FOR STORING, RETRIEVING, ACCESSING, RETAINING, AND DISPOSING OF RECORDS IN THE SYSTEM:

STORAGE:

Hard copy or electronically. Hard copies are maintained at the System Manager address.

RETRIEVABILITY:

Records can be retrieved by employer agency name, participant name, or any other identifier in the system

SAFEGUARDS:

Records in this system are safeguarded in accordance with applicable rules and policies, including all applicable DOT automated systems security and access policies. Appropriate controls have been imposed to minimize the risk of compromising the information that is being stored. Access to records in this system is limited to those individuals who have a need to know the information for the performance of their official duties and who have appropriate permissions.

RETENTION AND DISPOSAL:

Records in this system are retained for three years and then destroyed, in accordance with General Record Schedule 9, Item 7. Source documents provided to DOT by its Federal agencies customers are considered temporary records and are destroyed not more than 120 after of receipt by DOT.

SYSTEM MANAGER(S) AND ADDRESS:

OST Parking and Transit Office, 1200 New Jersey Ave. SE., Washington, DC 20950; FAA Transit Benefit Office, 800 Independence Ave. SW., Washington, DC 20591.

NOTIFICATION PROCEDURE:

Individuals seeking notification of and access to any record contained in this system of records, or seeking to contest its content, may submit a request in writing to the OST Parking and Transit Office at the contact information provided under ''System Manager and Address.'' FAA employees in the National Capital Region seeking notification of and access to any record contained in this system, or seeking to contest its content, may submit a request in writing to the FAA Transit Benefit Office at the contact information provided under ''System Manager and Address.''

When seeking records about yourself from this system of records or any other Departmental system of records your request must conform with the Privacy Act regulations set forth in 49 CFR part 10. You must sign your request, and your signature must either be notarized or submitted under 28 U.S.C. 1746, a law that permits statements to be made under penalty of perjury as a substitute for notarization. While no specific form is required, you may obtain forms for this purpose from the Departmental Freedom of Information Act Officer, *http://www.dot.gov/foia* or 202.366.4542. In addition you should provide the following:

- An explanation of why you believe the Department would have information on you;
- Identify which component(s) of the Department you believe may have the information about you;
- Specify when you believe the records would have been created;
- Provide any other information that will help the FOIA staff determine which DOT component agency may have responsive records; and

If your request is seeking records pertaining to another living individual, you must include a statement from that individual certifying his/her agreement for you to access his/her records. Without this bulleted information the component(s) may not be able to conduct an effective search, and your request may be denied due to lack of specificity or lack of compliance with applicable regulations.

RECORD ACCESS PROCEDURES:

See ''Notification procedure'' above.

CONTESTING RECORD PROCEDURES:

See ''Notification procedure'' above.

RECORD SOURCE CATEGORIES:

Records are obtain from applications submitted by individuals for parking permits, carpool and vanpool membership, ridesharing information, and fare subsidies; from notifications from other Federal agencies in the program; and from periodic certifications or recertifications and reports regarding fare subsidies.

EXEMPTIONS CLAIMED FOR THE SYSTEM:

None.

Claire W. Barrett,

Departmental Chief Privacy Officer.

[FR Doc. 2015–26974 Filed 10–22–15; 8:45 am]

BILLING CODE 4910–9X–P

DEPARTMENT OF THE TREASURY

Community Development Financial Institutions Fund

Funding Opportunity Title: Notice of Allocation Availability (NOAA) Inviting Applications for the Calendar Year (CY) 2015 Allocation Round of the New Markets Tax Credit (NMTC) Program

Announcement Type: Announcement of NMTC allocation availability.

DATES: Electronic applications must be received by 5:00 p.m. ET on December 16, 2015. Applications sent by mail, facsimile or other form will not be accepted. Please note the Community Development Financial Institutions Fund (CDFI Fund) will only accept applications and attachments (*i.e.,* the CDE's authorized representative signature page, the Controlling Entity's representative signature page, investor letters and organizational charts) in electronic form (see Section IV.C of this NOAA for more details). Applications must meet all eligibility and other requirements and deadlines, as applicable, set forth in this NOAA. Any Applicant that is not yet certified as a Community Development Entity (CDE) must submit an application for CDE certification through the CDFI Fund's Awards Management Information System (AMIS) on or before 5:00 p.m. ET on November 6, 2015 (see Section III.A.1 of this NOAA for more details on CDE certification).

Executive Summary: This NOAA is issued in connection with the CY 2015 allocation round (Allocation Round) of the New Markets Tax Credit (NMTC) Program, as authorized by Title I, subtitle C, section 121 of the Community Renewal Tax Relief Act of 2000 (Pub. L. 106–554) and amended by section 221 of the American Jobs Creation Act of 2004 (Pub. L. 108–357), section 101 of the Gulf Opportunity Zone Act of 2005 (Pub. L. 108–357), Division A, section 102 of the Tax Relief and Health Care Act of 2006 (Pub. L. 109–432), section 733 of the Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act of 2010 (Pub. L. 111–312), section 305 of the American Taxpayer Relief Act of 2012 (Pub. L. 112–240), and section 115 of the Tax Increase Prevention Act of 2014 (Pub. L. 113–295). Through the NMTC Program, the CDFI Fund provides authority to CDEs to offer an incentive to investors in the form of tax credits over seven years, which is expected to stimulate the provision of private investment capital that, in turn, will facilitate economic and community development in Low-Income Communities. Through this NOAA, the CDFI Fund announces the availability of up to $5.0 billion of NMTC investment authority in this Allocation Round, subject to Congressional authorization.

In this NOAA, the CDFI Fund specifically addresses how a CDE may apply to receive an allocation of NMTCs, the competitive procedure through which NMTC allocations will be made, and the actions that will be taken to ensure that proper allocations are made to appropriate entities.

I. Allocation Availability Description

A. *Programmatic changes from CY 2014 allocation round:*

1. As a condition of eligibility for this Allocation Round, the Applicant will not be permitted the use of the proceeds of Qualified Equity Investments (QEIs) to make Qualified Low-Income Community Investments (QLICIs) in Qualified Active Low-Income Community Businesses (QALICBs) where QLICI proceeds are used to repay or refinance any debt or equity provider or a party related to any debt or equity provider whose capital was used to fund the QEI except if: (i) The QLICI proceeds are used to repay documented reasonable expenditures that are directly attributable to the qualified business of the QALICB, and such past expenditures were incurred no more than 24 months prior to the QLICI closing date; or (ii) no more than five percent of the QLICI proceeds are used to repay or refinance prior investment in the QALICB. Refinance includes transferring cash or property directly to

any debt or equity provider or indirectly to a party related to any debt or equity provider.

2. *Prior QEI Issuance Requirements:* In order to be eligible to apply for a NMTC allocation in this Allocation Round, as described in Section III.A.3(a), any Applicant that received a NMTC allocation award in a previous Allocation round is required to meet the corresponding minimum Qualified Equity Investment (QEI) issuance threshold with respect to its prior-year allocation. These thresholds and deadlines have been revised in comparison to the CY 2014 NOAA.

B. *Program guidance and regulations:* This NOAA describes application and allocation requirements for this Allocation Round of the NMTC Program and should be read in conjunction with: (i) Guidance published by the CDFI Fund on how an entity may apply to become certified as a CDE (66 **Federal Register** 65806, December 20, 2001); (ii) the final regulations issued by the Internal Revenue Service (the IRS) (26 CFR 1.45D–1, published on December 28, 2004), as amended and related guidance, notices and other publications; and (iii) the application and related materials for this Allocation Round. All such materials may be found on the CDFI Fund's Web site at *https://www.cdfifund.gov.* The CDFI Fund encourages Applicants to review these documents. Capitalized terms used, but not defined, in this NOAA have the respective meanings assigned to them in the NMTC Program Allocation application, IRC § 45D or the IRS regulations. In the event of any inconsistency between this NOAA, the allocation application, and guidance issued by the CDFI Fund thereto, IRC § 45D or the IRS regulations, the provisions of IRC § 45D and the IRS regulations shall govern.

II. Allocation Information

A. *Allocation amounts:* Pursuant to the Act, the CDFI Fund expects that it may allocate to CDEs the authority to issue to their investors up to the aggregate amount of $5.0 billion in equity as to which NMTCs may be claimed, as permitted under IRC § 45D(f)(1)(D). Pursuant to this NOAA, the CDFI Fund anticipates that it will not issue more than $125 million in tax credit investment authority per Allocatee. The CDFI Fund, in its sole discretion, reserves the right to allocate amounts in excess of or less than the anticipated maximum allocation amount should the CDFI Fund deem it appropriate. In order to receive an allocation in excess of the $125 million cap, an Applicant, at a minimum, must demonstrate that: (i) No part of its strategy can be successfully implemented without an allocation in excess of the applicable cap; and/or (ii) its strategy will produce extraordinary community outcomes. The CDFI Fund reserves the right to allocate NMTC authority to any, all, or none of the entities that submit applications in response to this NOAA, and in any amounts it deems appropriate.

B. *Type of award:* NMTC Program awards are made in the form of allocations of tax credit investment authority.

C. *Allocation Agreement:* Each Allocatee must sign an Allocation Agreement, which must be countersigned by the CDFI Fund, before the NMTC allocation is effective. The Allocation Agreement contains the terms and conditions of the NMTC allocation. For further information, see Section VI of this NOAA.

III. Eligibility

A. *Eligible Applicants:* IRC § 45D specifies certain eligibility requirements that each Applicant must meet to be eligible to apply for an allocation of NMTCs. The following sets forth additional detail and certain additional dates that relate to the submission of applications under this NOAA for the available NMTC investment authority.

1. *CDE certification:* For purposes of this NOAA, the CDFI Fund will not consider an application for an allocation of NMTCs unless: (a) The Applicant is certified as a CDE at the time the CDFI Fund receives its NMTC Program allocation application; or (b) the Applicant submits an application for certification as a CDE through the CDFI Fund's Awards Management Information System (AMIS) on or before 5:00 p.m. ET on November 6, 2015. Applicants for CDE certification may obtain information regarding CDE certification and the CDE certification application process in AMIS on the CDFI Fund's Web site at *https://www.cdfifund.gov.* Applications for CDE certification must be submitted in AMIS. Paper versions of the CDE certification application will not be accepted.

The CDFI Fund will not provide NMTC allocation authority to Applicants that are not certified as CDEs or to entities that are certified as Subsidiary CDEs.

If an Applicant that has already been certified as a CDE wishes to change its designated CDE Service Area, it must submit its request for such change to the CDFI Fund, and the request must be received by the CDFI Fund by 5:00 p.m. ET on November 6, 2015. A request to change a CDE's Service Area must be submitted through the CDFI Fund's Awards Management Information System (AMIS) as a Service Request. Such requests will need to include, at a minimum, the applicable CDE control number, the revised service area designation, and updated accountability information that demonstrates that the CDE has the required representation from Low-Income Communities in the revised Service Area.

2. As a condition of eligibility for this Allocation Round, the Applicant will not be permitted the use of the proceeds of Qualified Equity Investments (QEIs) to make Qualified Low-Income Community Investments (QLICIs) in Qualified Active Low-Income Community Businesses (QALICBs) where QLICI proceeds are used to repay or refinance any debt or equity provider or a party related to any debt or equity provider whose capital was used to fund the QEI except if: (i) The QLICI proceeds are used to repay documented reasonable expenditures that are directly attributable to the qualified business of the QALICB, and such past expenditures were incurred no more than 24 months prior to the QLICI closing date; or (ii) no more than five percent of the QLICI proceeds are used to repay or refinance prior investment in the QALICB. Refinance includes transferring cash or property directly to any debt or equity provider or indirectly to a party related to any debt or equity provider.

3. *Prior award recipients or Allocatees:* Applicants must be aware that success in a prior application or allocation round of any of the CDFI Fund's programs is not indicative of success under this NOAA. For purposes of this section, the CDFI Fund will consider an Affiliate to be any entity that meets the definition of Affiliate as defined in the NMTC allocation application materials, or any entity otherwise identified as an Affiliate by the Applicant in its NMTC allocation application materials. Prior award recipients of any CDFI Fund program are eligible to apply under this NOAA, except as follows:

(a) *Prior Allocatees and Qualified Equity Investment (QEI) issuance requirements:* The following describes the QEI issuance requirements applicable to prior Allocatees.

An Allocatee in the CY 2010 allocation round of the NMTC Program is not eligible to receive a NMTC allocation pursuant to this NOAA unless the Allocatee is able to affirmatively demonstrate that, as of 11:59 p.m. ET on January 29, 2016, it has finalized at least 95 percent of its

QEIs relating to its CY 2010 NMTC allocation.

An Allocatee in the CY 2011 allocation round of the NMTC Program is not eligible to receive a NMTC allocation pursuant to this NOAA unless the Allocatee is able to affirmatively demonstrate that, as of 11:59 p.m. ET on January 29, 2016, it has: (i) Finalized at least 80 percent of its QEIs relating to its CY 2011 NMTC allocation; or (ii) it has finalized at least 70 percent of its QEIs and that at least 100 percent of its total CY 2011 NMTC allocation has been finalized, or has been committed by its investors.

An Allocatee in the CY 2012 allocation round of the NMTC Program is not eligible to receive a NMTC allocation pursuant to this NOAA unless the Allocatee is able to affirmatively demonstrate that, as of 11:59 p.m. ET on January 29, 2016, it has: (i) Finalized at least 70 percent of its QEIs relating to its CY 2012 NMTC allocation; or (ii) it has finalized at least 60 percent of its QEIs and that at least 80 percent of its total CY 2012 NMTC allocation has been finalized, or has been committed by its investors.

An Allocatee (with the exception of a Rural CDE Allocatee) in the CY 2013 allocation round of the NMTC Program is not eligible to receive a NMTC allocation pursuant to this NOAA unless the Allocatee is able to affirmatively demonstrate that, as of 11:59 p.m. ET on January 29, 2016, it has: (i) Finalized at least 50 percent of its QEIs relating to its CY 2013 NMTC allocation; or (ii) it has finalized at least 40 percent of its QEIs and that at least 60 percent of its total CY 2013 NMTC allocation has been finalized, or has been committed by its investors. A prior Rural CDE Allocatee in the CY 2013 is not eligible to receive a NMTC allocation pursuant to this NOAA unless the Allocatee can demonstrate that, as of 11:59 p.m. ET on January 29, 2016, it has finalized at least 30 percent of its CY 2013 NMTC Allocation.

An Allocatee (with the exception of a Rural CDE Allocatee) in the CY 2014 allocation round of the NMTC Program is not eligible to receive a NMTC allocation pursuant to this NOAA unless the Allocatee is able to affirmatively demonstrate that, as of 11:59 p.m. ET on January 29, 2016, it has: (i) Finalized at least 30 percent of its QEIs relating to its CY 2014 NMTC allocation; or (ii) finalized at least 20 percent of its QEIs and that at least 50 percent of its total CY 2014 NMTC allocation has been finalized, or has been committed by its investors. A Rural CDE is not required to meet the above QEI issuance and commitment thresholds with regard to its CY 2014 NMTC allocation award.

Alternatively, an Applicant that has received multiple NMTC allocations between CY 2010 and CY 2014 can also meet the QEI issuance requirements on a cumulative basis. If an Applicant has received multiple NMTC allocation awards between CY 2010 and CY 2014, the Applicant shall be deemed to be eligible to apply for a NMTC allocation pursuant to this NOAA if the Applicant is able to affirmatively demonstrate that, as of 11:59 p.m. ET on January 29, 2016, it has finalized at least 90 percent of its QEIs relating to its cumulative allocation amounts from these prior NMTC Program rounds. Rural CDEs that received allocations under the CY 2013 allocation round may choose to exclude such allocations from this cumulative calculation, provided that the Allocatee has finalized at least 20 percent of its QEIs relating to its CY 2013 allocation. Rural CDEs that received allocations under the CY 2014 allocation round may choose to exclude such allocation from this cumulative calculation.

In addition to the requirements described above, an entity is not eligible to receive a NMTC allocation pursuant to this NOAA if an Affiliate of the Applicant is a prior Allocatee and has not met the requirements for the issuance and/or commitment of QEIs as set forth above for the Allocatees in the prior allocation rounds of the NMTC Program.

For purposes of this section of the NOAA, the CDFI Fund will only recognize as ''finalized'' those QEIs that have been properly reported in the CDFI Fund's Allocation Tracking System (ATS) by the deadlines specified above. Allocatees and their Subsidiary Allocatees, if any, are advised to access ATS to record each QEI that they issue to an investor in exchange for funds in-hand. For purposes of this section of the NOAA, ''committed'' QEIs are only those Equity Investments that are evidenced by a written, signed document in which an investor: (i) Commits to make a QEI in the Allocatee in a specified amount and on specified terms; (ii) has made an initial disbursement of the investment proceeds to the Allocatee, and such initial disbursement has been recorded in ATS as a QEI; (iii) commits to disburse the remaining investment proceeds to the Allocatee based on specified amounts and payment dates; and (iv) commits to make the final disbursement to the Allocatee no later than January 29, 2018.

The Applicant will be required, upon notification from the CDFI Fund, to submit adequate documentation to substantiate the required issuances of and commitments for QEIs.

Applicants should be aware that these QEI issuance requirements represent the minimum threshold requirements that must be met in order to submit an application for assistance under this NOAA. As stated in Section V.C.1 of this NOAA, the CDFI Fund reserves the right to reject an application and/or adjust award amounts as appropriate based on information obtained during the review process—including an Applicant's track record of raising QEIs and/or deploying its Qualified Low Income Community Investments (QLICIs).

Any prior Allocatees that requires any action by the CDFI Fund (*i.e.,* certifying a subsidiary entity as a CDE; adding a subsidiary CDE to an Allocation Agreement; etc.) in order to meet the QEI issuance requirements above must submit a Certification Application for subsidiary CDEs by no later than November 6, 2015 and Allocation Agreement Amendment requests by no later than December 31, 2015 in order to guarantee that the CDFI Fund completes all necessary approvals prior to January 29, 2016. Applicants for CDE certification may obtain information regarding CDE certification and the CDE certification application process in AMIS on the CDFI Fund's Web site at *https://www.cdfifund.gov.* Applications for CDE certification must be submitted in AMIS. Paper versions of the CDE certification application will not be accepted.

(b) *Pending determination of noncompliance or default:* If an Applicant is a prior award recipient or Allocatee under any CDFI Fund program and if: (i) It has submitted reports to the CDFI Fund that demonstrate potential noncompliance with or default under a previous assistance, award or Allocation Agreement; and (ii) the CDFI Fund has yet to make a final determination as to whether the entity is in noncompliance or default of its previous assistance, award or Allocation Agreement, the CDFI Fund will consider the Applicant's application under this NOAA pending final determination of whether the entity is in noncompliance or default, in the sole determination of the CDFI Fund. Further, if an Affiliate of the Applicant is a prior CDFI Fund award recipient or Allocatee and if such entity: (i) Has submitted reports to the CDFI Fund that demonstrate potential noncompliance with or default under a previous assistance, award or Allocation Agreement; and (ii) the CDFI Fund has yet to make a final determination as to whether the entity is in noncompliance or default of its previous assistance, award or Allocation Agreement, the CDFI Fund will consider the Applicant's application under this NOAA pending final determination of whether the entity is in noncompliance or default, in the sole determination of the CDFI Fund.

Any Applicant or Affiliate that is in default of its previously executed Allocation Agreement is deemed ineligible under this NOAA if: (i) The CDFI Fund has made a determination that such Applicant is in default of a previously executed Allocation Agreement and (ii) the CDFI Fund has provided written notification of such determination to the Applicant. Moreover, any Applicant that is otherwise eligible as of the application deadline must continue to be compliant with its Allocation Agreement(s) after the application deadline, in order for the CDFI Fund to continue evaluating its application. If an Applicant fails to do such, the CDFI Fund will no longer deem the Applicant eligible.

(c) *Default status:* The CDFI Fund will not consider an application submitted by an Applicant that is a prior CDFI Fund award recipient or Allocatee under any CDFI Fund program if, as of the application deadline of this NOAA: (i) The CDFI Fund has made a determination that such Applicant is in default of a previously executed assistance, allocation, or award agreement; (ii) the CDFI Fund has provided written notification of such determination to the Applicant; and (iii) the application deadline of the NOAA is within a period of time specified in the CDFI Fund's notification to the prior CDFI Fund award recipient or Allocatee for which any new application from the Applicant to the CDFI Fund for an award, allocation, or assistance is prohibited. Further, the CDFI Fund will not consider an application submitted by an Applicant for which there is an Affiliate that is a prior award recipient or Allocatee under any CDFI Fund Program if, as of the application deadline of this NOAA: (i) The CDFI Fund has made a determination that such Affiliate is in default of a previously executed assistance, allocation, or award agreement; (ii) the CDFI Fund has provided written notification of such determination to the Affiliate; and (iii) the application deadline of the NOAA is within a period of time specified in a notification to the prior CDFI Fund award recipient or Allocatee for which any new application from the Affiliate to the CDFI Fund for an award, allocation, or assistance is prohibited.

(d) *Undisbursed award funds:* The CDFI Fund will not consider an application submitted by an Applicant that is a prior award recipient under the CDFI Program (CDFI), Native Initiatives (NI), and Bank Enterprise Award (BEA) Program if the Applicant has a balance of undisbursed award funds (defined below) under said prior award(s), as of the applicable application deadline of this NOAA. Furthermore, an entity is not eligible to apply for an award pursuant to this NOAA if an Affiliate of the Applicant is a prior award recipient under any CDFI Fund program, and has a balance of undisbursed award funds under said prior award(s), as of the applicable application deadline of this NOAA. In a case where an Affiliate of the Applicant is a prior award recipient under any CDFI Fund program and has a balance of undisbursed award funds under said prior award(s) as of the applicable application deadline of this NOAA, the CDFI Fund will include the combined awards of the Applicant and such Affiliated entities when calculating the amount of undisbursed award funds.

For purposes of the calculation of undisbursed award funds for the BEA Program, only awards made to the Applicant (and any Affiliates) three to five calendar years prior to the end of the calendar year of the application deadline of this NOAA are included (''includable BEA awards''). Thus, for purposes of this NOAA, undisbursed BEA Program award funds are the amount of FYs 2010, 2011, 2012 awards that remain undisbursed as of the application deadline of this NOAA.

For purposes of the calculation of undisbursed award funds for the CDFI Program and the NI, only awards made to the Applicant (and any entity that Controls the Applicant, is Controlled by the Applicant or shares common management officials with the Applicant, as determined by the CDFI Fund) two to five calendar years prior to the end of the calendar year of the application deadline of this NOAA are included (''includable CDFI/NI awards''). Thus, for purposes of this NOAA, undisbursed CDFI Program and NI awards are the amount of FYs 2010, 2011, 2012, and 2013 awards that remain undisbursed as of the application deadline of this NOAA.

To calculate total includable BEA/CDFI/NI awards: Amounts that are undisbursed as of the application deadline of this NOAA cannot exceed five percent (5%) of the total includable awards. Please refer to an example of this calculation in the Round Allocation Application Q&A document, available on the CDFI Fund's Web site.

The ''undisbursed award funds'' calculation does not include: (i) NMTC allocation authority; (ii) any award funds for which the CDFI Fund received a full and complete disbursement request from the award recipient by the applicable application deadline of this NOAA; (iii) any award funds for an award that has been terminated, in writing, by the CDFI Fund or de-obligated by the CDFI Fund; or (iv) any award funds for an award that does not have a fully executed assistance or award agreement. The CDFI Fund strongly encourages Applicants requesting disbursements of ''undisbursed funds'' from prior awards to provide the CDFI Fund with a complete disbursement request at least 30 business days prior to the application deadline of this NOAA.

(e) *Contact the CDFI Fund:* Accordingly, Applicants that are prior award recipients and/or Allocatees under any other CDFI Fund program are advised to: (i) Comply with the requirements specified in assistance, allocation and/or award agreement(s), and (ii) contact the CDFI Fund as necessary to ensure that all required actions are underway for the disbursement of any outstanding balance of a prior award(s). All outstanding reports and compliance questions should be directed to the Office of Certification, Compliance Monitoring, and Evaluation through a Service Request initiated in AMIS. All disbursement questions related to the CDFI and NACA Programs should be directed to the CDFI Fund Help Desk by telephone at (202) 653–0421 (Option 1 for CDFI Program, Option 2 for the NACA Program) or via email at *cdfihelp@cdfi.treas.gov.* All disbursement questions related to the BEA Program should be directed to the CDFI Fund Help Desk by telephone at (202) 653–0421 (Option 4 for BEA Program) or via email at *cdfihelp@cdfi.treas.gov.* Requests submitted less than thirty calendar days prior to the application deadline may not receive a response before the application deadline.

The CDFI Fund will respond to Applicants' reporting, compliance or disbursement questions between the hours of 9:00 a.m. and 5:00 p.m. ET, starting the date of publication of this NOAA through December 14, 2015 (two days before the application deadline). The CDFI Fund will not respond to Applicants' reporting, compliance, CDE certification, or disbursement phone calls or email inquiries that are received after 5:00 p.m. ET on December 14, 2015 until after the funding application deadline of December 16, 2015.

4. *Failure to accurately respond to a question in the Assurances and Certifications section of the application and submit the required written explanation:* In its sole discretion, the CDFI Fund may deem the Applicant's application ineligible, if the CDFI Fund determines that the Applicant inaccurately responded to a question and failed to submit a required written explanation, or accurately answered a question yet failed to submit a required written explanation, with respect to the application Assurances and Certifications. In making this determination, the CDFI Fund will take into consideration, among other factors, the materiality of the question, the substance of any supplemental responses provided, and whether the information in the Applicant's supplemental responses will have a material adverse effect on the Applicant, its financial condition or its ability to perform under an allocation agreement, should the Applicant receive an allocation.

5. *Entities that propose to transfer NMTCs to Subsidiaries:* Both for-profit and non-profit CDEs may apply for NMTC allocation authority, but only a for-profit CDE is permitted to provide NMTCs to its investors. A non-profit Applicant wishing to apply for a NMTC allocation must demonstrate, prior to entering into an Allocation Agreement with the CDFI Fund, that: (i) It controls one or more Subsidiaries that are for-profit entities; and (ii) it intends to transfer the full amount of any NMTC allocation it receives to said Subsidiaries.

An Applicant wishing to transfer all or a portion of its NMTC allocation to a Subsidiary is not required to create the Subsidiary prior to submitting a NMTC allocation application to the CDFI Fund. However, the Subsidiary entities must be certified as CDEs by the CDFI Fund, and enjoined as parties to the Allocation Agreement at closing or by amendment to the Allocation Agreement after closing. Before the NMTC allocation transfer may occur it must be pre-approved by the CDFI Fund, in its sole discretion.

The CDFI Fund strongly encourages a non-profit Applicant to submit a CDE certification application to the CDFI Fund on behalf of at least one Subsidiary within 60 days after the non-profit Applicant receives the Notice of Allocation (NOA) from the CDFI Fund, as such Subsidiary must be certified as a CDE prior to entering into an Allocation Agreement with the CDFI Fund. A non-profit Applicant that does not already have a certified for-profit Subsidiary and that fails to submit a certification application for one or more for-profit Subsidiaries within 60 days of the date of the NOA from the CDFI Fund is subject to the CDFI Fund rescinding the award.

6. *Entities that submit applications together with Affiliates; applications from common enterprises:*

(a) As part of the allocation application review process, the CDFI Fund will evaluate whether Applicants are Affiliates, as such term is defined in the allocation application. If an Applicant and its Affiliate(s) wish to submit allocation applications, they must do so collectively, in one application; an Applicant and its Affiliate(s) may not submit separate allocation applications. If Affiliated entities submit multiple applications, the CDFI Fund will reject all such applications received, except for those State–owned or State–controlled governmental Affiliated entities. In the case of State-owned or State-controlled governmental entities, the CDFI Fund may accept applications submitted by different government bodies within the same State, but only to the extent the CDFI Fund determines that the business strategies and/or activities described in such applications, submitted by separate entities, are distinctly dissimilar and/or are operated and/or managed by distinctly dissimilar personnel, including staff, board members or identified consultants. If the CDFI Fund determines that the applications submitted by different government bodies in the same State are not distinctly dissimilar and/or operated and/or managed by distinctly dissimilar personnel, it will reject all such applications. In such cases, the CDFI Fund reserves the right to limit award amounts to such entities to ensure that the entities do not collectively receive more than the $125 million cap.

(b) For purposes of this NOAA, the CDFI Fund will also evaluate whether each Applicant is operated or managed as a ''common enterprise'' with another Applicant in this Allocation Round using the following indicia, among others: (i) Whether different Applicants have the same individual(s), including the Authorized Representative, staff, board members and/or consultants, involved in day-to-day management, operations and/or investment responsibilities; (ii) whether the Applicants have business strategies and/or proposed activities that are so similar or so closely related that, in fact or effect, they may be viewed as a single entity; and/or (iii) whether the applications submitted by separate Applicants contain significant narrative, textual or other similarities such that they may, in fact or effect, be viewed as substantially identical applications. In such cases, the CDFI Fund will reject all applications received from such entities.

(c) Furthermore, an Applicant that receives an allocation in this Allocation Round (or its Subsidiary Allocatee) may not become an Affiliate of or member of a common enterprise (as defined above) with another Applicant that receives an allocation in this Allocation Round (or its Subsidiary Allocatee) at any time after the submission of an allocation application under this NOAA. This prohibition, however, generally does not apply to entities that are commonly Controlled solely because of common ownership by QEI investors. This requirement will also be a term and condition of the Allocation Agreement (see Section VI.B of this NOAA and additional application guidance materials on the CDFI Fund's Web site at *https://www.cdfifund.gov* for more details).

7. *Entities created as a series of funds:* An Applicant whose business structure consists of an entity with a series of funds must apply for CDE certification for each fund. If such an Applicant represents that it is properly classified for Federal tax purposes as a single partnership or corporation, it may apply for CDE certification as a single entity. If an Applicant represents that it is properly classified for Federal tax purposes as multiple partnerships or corporations, then it must submit a CDE certification application for the Applicant and each fund it would like to participate in the NMTC Program, and each fund must be separately certified as a CDE. Applicants should note, however, that receipt of CDE certification as a single entity or as multiple entities is not a determination that an Applicant and its related funds are properly classified as a single entity or as multiple entities for Federal tax purposes. Regardless of whether the series of funds is classified as a single partnership or corporation or as multiple partnerships or corporations, an Applicant may not transfer any NMTC allocations it receives to one or more of its funds unless the fund is a certified CDE that is a Subsidiary of the Applicant, enjoined to the Allocation Agreement as a Subsidiary Allocatee.

8. *Entities that are BEA Program award recipients:* An insured depository institution investor (and its Affiliates and Subsidiaries) may not receive a NMTC allocation in addition to a BEA Program award for the same investment in a CDE. Likewise, an insured depository institution investor (and its Affiliates and Subsidiaries) may not receive a BEA Program award in

addition to a NMTC allocation for the same investment in a CDE.

IV. Application and Submission Information

A. *Address to request application package:* Applicants must submit applications electronically under this NOAA, through the CDFI Fund Web site. Following the publication of this NOAA, the CDFI Fund will make the electronic allocation application available on its Web site at *https://www.cdfifund.gov.* Applications sent by mail, facsimile or other form will not be accepted. Please note the CDFI Fund will only accept the application and attachments (*i.e.,* the Applicant's authorized representative signature page, the Controlling Entity's representative signature page, investor letters and organizational charts) in electronic form.

B. *Application content requirements:* Detailed application content requirements are found in the application related to this NOAA. Applicants must submit all materials described in and required by the application by the applicable deadlines. Applicants will not be afforded an opportunity to provide any missing materials or documentation, except, if necessary and at the request of the CDFI Fund. Electronic applications must be submitted solely by using the format made available at the CDFI Fund's Web site. Additional information, including instructions relating to the submission of supporting information (*i.e.,* the Applicant's authorized representative signature page, the Controlling Entity's representative signature page, investor letters and organizational charts), is set forth in further detail in the electronic application. An application must include a valid and current Employer Identification Number (EIN) issued by the Internal Revenue Service (IRS) and assigned to the Applicant and, if applicable, its Controlling Entity. Electronic applications without a valid EIN are incomplete and cannot be transmitted to the CDFI Fund. For more information on obtaining an EIN, please contact the IRS at (800) 829–4933 or *www.irs.gov.* Do not include any personal Social Security Numbers as part of the application.

An Applicant may not submit more than one application in response to this NOAA. In addition, as stated in Section III.A.6 of this NOAA, an Applicant and its Affiliates must collectively submit only one allocation application; an Applicant and its Affiliates may not submit separate allocation applications except as outlined in Section III.A.6 above. Once an application is submitted, an Applicant will not be allowed to change any element of its application.

C. *Form of application submission:* Applicants may only submit applications under this NOAA electronically. Applications sent by facsimile or by email will not be accepted. Submission of an electronic application will facilitate the processing and review of applications and the selection of Allocatees; further, it will assist the CDFI Fund in the implementation of electronic reporting requirements.

1. *Electronic applications:* Electronic applications must be submitted solely by using the CDFI Fund's Web site and must be sent in accordance with the submission instructions provided in the electronic application form. The CDFI Fund recommends use of Internet Explorer version 8 or higher on a Microsoft Windows-based computer (Windows Vista or higher), and optimally at least a 56Kbps Internet connection in order to meet the electronic application submission requirements. Use of other browsers (*i.e.,* Firefox, Chrome, Safari), other versions of Internet Explorer, or other systems (*i.e.,* Mac) might result in problems during submission of the application. The CDFI Fund's electronic application system will only permit the submission of applications in which all required questions and tables are fully completed. Additional information, including instructions relating to the submission of supporting information (*i.e.,* the Applicant's authorized representative signature page, the Controlling Entity's representative signature page, investor letters and organizational charts) is set forth in further detail in the electronic application and the Online Application Instructions for this Allocation Round.

D. *Application submission dates and times:*

1. *Application deadlines:*

(a) *Electronic applications:* Must be received by 5:00 p.m. ET on December 16, 2015. Electronic applications cannot be transmitted or received after 5:00 p.m. ET on December 16, 2015. In addition, Applicants must separately submit supporting information (*i.e.,* the Applicant's authorized representative signature page, the Controlling Entity's representative signature page, investor letters and organizational charts) via their myCDFIFund account. The Applicant's authorized representative signature page, the Controlling Entity's representative signature page, investor letters and organizational charts must be submitted on or before 11:59 p.m. on December 18, 2015. Attachments may not exceed a size limit of 5 megabytes (MB). See application instructions, provided in the electronic application and the Round Allocation Application Q&A, for further detail. Applications and other required documents received after this date and time will be rejected. If the Applicant's authorized representative signature page is not received by the deadline specified above, the CDFI Fund reserves the right to reject the application. Please note that the document submission deadlines in this NOAA and/or the allocation application are strictly enforced.

E. *Intergovernmental Review:* Not applicable.

F. *Funding Restrictions:* For allowable uses of investment proceeds related to a NMTC allocation, please see 26 U.S.C. 45D and the final regulations issued by the Internal Revenue Service (26 CFR 1.45D–1, published December 28, 2004 and as amended) and related guidance. Please see Section I, above, for the Programmatic Changes of this NOAA.

G. *Paperwork Reduction:* Under the Paperwork Reduction Act (44 U.S.C. chapter 35), an agency may not conduct or sponsor a collection of information, and an individual is not required to respond to a collection of information, unless it displays a valid OMB control number. Pursuant to the Paperwork Reduction Act, the application has been assigned the following control number: 1559–0016.

V. Application Review Information

A. *Review and selection process:* All allocation applications will be reviewed for eligibility and completeness. To be complete, the application must contain, at a minimum, all information described as required in the application form. An incomplete application will be rejected. Once the application has been determined to be eligible and complete, the CDFI Fund will conduct the substantive review of each application in two parts (Phase 1 and Phase 2) in accordance with the criteria and procedures generally described in this NOAA and the allocation application.

In Phase 1, three reviewers will evaluate and score the Business Strategy and Community Outcomes sections of each application. An Applicant must exceed a minimum overall aggregate base score threshold *and* exceed a minimum aggregate section score threshold in each scored section in order to advance from the Phase 1 to the Phase 2 part of the substantive review process. In Phase 2, the CDFI Fund will rank Applicants and determine the dollar amount of allocation authority awarded in accordance with the procedures set forth below.

B. *Criteria:*

1. *Business Strategy* (25-point maximum):

(a) When assessing an Applicant's business strategy, reviewers will consider, among other things: The Applicant's products, services and investment criteria; the prior performance of the Applicant or its Controlling Entity, particularly as it relates to making similar kinds of investments as those it proposes to make with the proceeds of QEIs; the Applicant's prior performance in providing capital or technical assistance to disadvantaged businesses or communities; the projected level of the Applicant's pipeline of potential investments; the extent to which the Applicant intends to make QLICIs in one or more businesses in which persons unrelated to the entity hold a majority equity interest; and the extent to which Applicants that otherwise have notable relationships with the Qualified Active Low Income Community Businesses (QALICBs) financed will create benefits (beyond those created in the normal course of a NMTC transaction) to Low-Income Communities.

Under the Business Strategy criterion, an Applicant will generally score well to the extent that it will deploy debt or investment capital in products or services which are flexible or non-traditional in form and on better terms than available in the marketplace. An Applicant will also score well to the extent that, among other things: (i) It has a track record of successfully deploying loans or equity investments and providing services similar to those it intends to provide with the proceeds of QEIs; (ii) it has identified a set of clearly-defined potential borrowers or investees; (iii) its projected dollar volume of NMTC deployment is supported by its track record of deployment; (iv) in the case of an Applicant proposing to purchase loans from CDEs, the Applicant will require the CDE selling such loans to re-invest the proceeds of the loan sale to provide additional products and services to Low-Income Communities.

(b) *Priority Points:* In addition, as provided by IRC § 45D(f)(2), the CDFI Fund will ascribe additional points to entities that meet one or both of the statutory priorities. First, the CDFI Fund will give up to five (5) additional points to any Applicant that has a record of having successfully provided capital or technical assistance to disadvantaged businesses or communities. Second, the CDFI Fund will give five (5) additional points to any Applicant that intends to satisfy the requirement of IRC § 45D(b)(1)(B) by making QLICIs in one or more businesses in which persons unrelated (within the meaning of IRC § 267(b) or IRC § 707(b)(1)) to an Applicant (or the Applicant's subsidiary CDEs) hold the majority equity interest. Applicants may earn points for one or both statutory priorities. Thus, Applicants that meet the requirements of both priority categories can receive up to a total of ten (10) additional points. A record of having successfully provided capital or technical assistance to disadvantaged businesses or communities may be demonstrated either by the past actions of an Applicant itself or by its Controlling Entity (*i.e.,* where a new CDE is established by a nonprofit corporation with a history of providing assistance to disadvantaged communities). An Applicant that receives additional points for intending to make investments in unrelated businesses and is awarded a NMTC allocation must meet the requirements of IRC § 45D(b)(1)(B) by investing substantially all of the proceeds from its QEIs in unrelated businesses. The CDFI Fund will factor in an Applicant's priority points when ranking Applicants during Phase 2 of the review process, as described below.

2. *Community Outcomes* (25-point maximum): In assessing the potential benefits to Low-Income Communities that may result from the Applicant's proposed investments, reviewers will consider, among other things, the degree to which the Applicant is likely to: (i) Achieve significant and measurable community development outcomes in its Low-Income Communities; (ii) invest in particularly economically distressed markets: (iii) Engage with local communities regarding investments; (iv) the level of involvement of community representatives in the Governing Board and/or Advisory Board in approving investment criteria or decisions; and (v) demonstrate a track record of investing in businesses that spur additional private capital investment in Low-Income Communities.

An Applicant will generally score well under this section to the extent that, among other things: (a) It has a track record of producing quantitative and qualitative community outcomes that are similar to those projected to be achieved with an NMTC allocation; (b) it is working in particularly economically distressed or otherwise underserved communities; (c) its activities are part of a broader community or economic development strategy; (d) it demonstrates a track record of community engagement around past investment decisions; (e) it ensures that an NMTC investment into a project or business is supported by and will be beneficial to Low-Income Persons and residents of Low-Income Communities (LICs); and (f) it is likely to engage in activities that will spur additional private capital investment.

C. *Phase 2 Evaluation.*

1. *Final Rank Score*

(a). *Anomaly Reviews:* Using the numeric scores from Phase 1, Applicants are ranked on the basis of each Applicant's combined scores in the Business Strategy and Community Outcomes sections of the application plus one half of the priority points. If, in the case of a particular application, a reviewer's total base score or section score(s) (in one or more of the two application scored sections) varies significantly from the median of the three reviewers' total base scores or section scores for such application, the CDFI Fund may, in its sole discretion, obtain the evaluation and numeric scoring of an additional fourth reviewer to determine whether the anomalous score should be replaced with the score of the additional fourth reviewer.

(b). *Late Reports:* In the case of an Applicant or any Affiliates that has previously received an award or allocation from the CDFI Fund through any CDFI Fund program, the CDFI Fund will deduct points from the Applicant's ''Final Rank Score'' for the Applicant's (or its Affiliate's) failure to meet any of the reporting deadlines set forth in any assistance, award or Allocation Agreement(s), if the reporting deadlines occurred during the period from October 1, 2014 to the application deadline in this NOAA (December 16, 2015).

(c). *Prior Year Allocatees:* In the case of Applicants (or their Affiliates) that are prior year Allocatees, the CDFI Fund will review the activities of the prior year Allocatee to determine whether the entity has: (i) Effectively utilized its prior-year allocations in a manner generally consistent with the representations made in the relevant allocation application; and (ii) substantiated a need for additional allocation authority.

The CDFI Fund will award allocations in the order of the ''Final Rank Score,'' subject to Applicants meeting all other eligibility requirements; provided, however, that the CDFI Fund, in its sole discretion, reserves the right to reject an application and/or adjust award amounts as appropriate based on information obtained during the review process.

2. *Management Capacity:* In assessing an Applicant's management capacity, CDFI Fund will consider, among other

things, the qualifications of the Applicant's Principals, its board members, its management team, and other essential staff or contractors, with specific focus on: Experience in deploying capital or technical assistance, including activities similar to those described in the Applicant's business strategy; asset management and risk management experience; experience with fulfilling compliance requirements of other governmental programs, including other tax programs; and the Applicant's (or its Controlling Entity's) financial health. CDFI Fund evaluators will also consider the extent to which an Applicant has protocols in place to ensure ongoing compliance with NMTC Program requirements and the Applicant's projected income and expenses related to managing an NMTC allocation.

An Applicant will be generally evaluated more favorably under this section to the extent that its management team or other essential personnel have experience in: (a) Deploying capital or technical assistance in Low-Income Communities, particularly those likely to be served by the Applicant with the proceeds of QEIs; (b) asset and risk management; and (c) fulfilling government compliance requirements, particularly tax credit program compliance. An Applicant will also be evaluated favorably to the extent it demonstrates strong financial health and a high likelihood of remaining a going-concern; it clearly explains levels of income and expenses; has policies and systems in place to ensure ongoing compliance with NMTC Program requirements; and, if it is a Federally-insured financial institution, its most recent Community Reinvestment Act (CRA) rating was ''outstanding.''

3. *Capitalization Strategy:* When assessing an Applicant's capitalization strategy, CDFI Fund will consider, among other things: The key personnel of the Applicant (or Controlling Entity) and their track record of raising capital, particularly from for-profit investors; the extent to which the Applicant has secured investments or commitments to invest in NMTC (if applicable), or indications of investor interest commensurate with its requested amount of tax credit allocations, or, if a prior Allocatee, the track record of the Applicant or its Affiliates in raising Qualified Equity Investments in the past five years; the Applicant's strategy for identifying additional investors, if necessary, including the Applicant's (or its Controlling Entity's) prior performance with raising equity from investors, particularly for-profit investors; the distribution of the economic benefits of the tax credit; and the extent to which the Applicant intends to invest the proceeds from the aggregate amount of its QEIs at a level that exceeds the requirements of IRC § 45D(b)(1)(B) and the IRS regulations.

An Applicant will be evaluated more favorably under this section to the extent that: (a) It or its Controlling Entity demonstrate a track record of raising investment capital; (b) it has secured investor commitments, or has a reasonable strategy for obtaining such commitments, or, if it or its Affiliates is a prior Allocatee with a track record in the past five years of raising Qualified Equity Investments or; (c) it generally demonstrates that the economic benefits of the tax credit will be passed through to a QALICB; and (d) it intends to invest the proceeds from the aggregate amount of its QEIs at a level that exceeds the requirements of IRC § 45D(b)(1)(B) and the IRS regulations. In the case of an Applicant proposing to raise investor funds from organizations that also will identify or originate transactions for the Applicant or from Affiliated entities, said Applicant will be evaluated more favorably to the extent that it will offer products with more favorable rates or terms than those currently offered by its investor(s) or Affiliated entities and/or will target its activities to areas of greater economic distress than those currently targeted by the investor or Affiliated entities.

D. *Allocations serving Non-Metropolitan counties:* As provided for under Section 102(b) of the Tax Relief and Health Care Act of 2006 (P. L. 109–432), the CDFI Fund shall ensure that Non-Metropolitan counties receive a proportional allocation of QEIs under the NMTC Program. To this end, the CDFI Fund will ensure that the proportion of Allocatees that are Rural CDEs is, at a minimum, equal to the proportion of Applicants in the highly qualified pool that are Rural CDEs. The CDFI Fund will also endeavor to ensure that 20 percent of the QLICIs to be made using QEI proceeds are invested in Non-Metropolitan counties. A Rural CDE is one that has a track record of at least three years of direct financing experience, has dedicated at least 50 percent of its direct financing dollars to Non-Metropolitan counties over the past five years, and has committed that at least 50 percent of its NMTC financing dollars with this Allocation will be deployed in such areas. Non-Metropolitan counties are counties not contained within a Metropolitan Statistical Area, as such term is defined in OMB Bulletin No. 10–02 (Update of Statistical Area Definitions and Guidance on Their Uses) and applied using 2010 census tracts.

Applicants that meet the minimum scoring thresholds will be advanced to Phase 2 review and will be provided with ''preliminary'' awards, in descending order of Final Rank Score, until the available allocation authority is fulfilled. Once these ''preliminary'' award amounts are determined, the CDFI Fund will then analyze the Allocatee pool to determine whether the two Non-Metropolitan proportionality objectives have been met.

The CDFI Fund will first examine the ''preliminary'' awards and Allocatees to determine whether the percentage of Allocatees that are Rural CDEs is, at a minimum, equal to the percentage of Applicants in the highly qualified pool that are Rural CDEs. If this objective is not achieved, the CDFI Fund will provide awards to additional Rural CDEs from the highly qualified pool, in descending order of their Final Rank Score, until the appropriate percentage balance is achieved. In order to accommodate the additional Rural CDEs in the Allocatee pool within the available allocation limitations, a formula reduction will be applied as uniformly as possible to the allocation amount for all Allocatees in the pool that have not committed to investing a minimum of 20 percent of their QLICIs in Non-Metropolitan counties.

The CDFI Fund will then determine whether the pool of Allocatees will, in the aggregate, invest at least 20 percent of their QLICIs (as measured by dollar amount) in Non-Metropolitan counties. The CDFI Fund will first apply the ''minimum'' percentage of QLICIs that Allocatees indicated in their applications would be targeted to Non-Metropolitan areas to the total allocation award amount of each Allocatee (less whatever percentage the Allocatee indicated would be retained for non-QLICI activities), and total these figures for all Allocatees. If this aggregate total is greater than or equal to 20 percent of the QLICIs to be made by the Allocatees, then the pool is considered balanced and the CDFI Fund will proceed with the allocation process. However, if the aggregate total is less than 20 percent of the QLICIs to be made by the Allocatees, the CDFI Fund will consider requiring any or all of the Allocatees to direct up to the ''maximum'' percentage of QLICIs that the Allocatees indicated would be targeted to Non-Metropolitan counties, taking into consideration their track record and ability to deploy dollars in Non-Metropolitan counties. If the CDFI Fund cannot meet the goal of 20 percent of QLICIs in Non-Metropolitan counties by requiring any or all Allocatees to commit up to the maximum percentage of QLICIs that they indicated would be targeted to Non-Metropolitan counties, the CDFI Fund may add additional Rural CDEs (in descending order of final rank score) to the Allocatee pool. In order to accommodate any additional Allocatees within the allocation limitations, a formula reduction will be applied as uniformly as possible, to the allocation amount for all Allocatees in the pool that have not committed to investing a minimum of 20 percent of their QLICIs in Non-Metropolitan counties.

E. *Questions:* All outstanding reports or compliance questions should be directed to the Office of Certification, Compliance Monitoring, and Evaluation through the submission of a Service Request in AMIS or by telephone at (202) 653–0423. The CDFI Fund will respond to reporting or compliance questions between the hours of 9:00 a.m. and 5:00 p.m. ET, starting the date of the publication of this NOAA through December 14, 2015. The CDFI Fund will not respond to reporting or compliance phone calls or email inquiries that are received after 5:00 p.m. ET on December 14, 2015 until after the funding application deadline of December 16, 2015.

F. *Right of rejection:* The CDFI Fund reserves the right to reject any NMTC allocation application in the case of a prior CDFI Fund award recipient, if such Applicant has failed to comply with the terms, conditions, and other requirements of the prior or existing assistance or award agreement(s) with the CDFI Fund. The CDFI Fund reserves the right to reject any NMTC allocation application in the case of a prior CDFI Fund Allocatee, if such Applicant has failed to comply with the terms, conditions, and other requirements of its prior or existing Allocation Agreement(s) with the CDFI Fund. The CDFI Fund reserves the right to reject any NMTC allocation application in the case of any Applicant, if an Affiliate of the Applicant has failed to meet the terms, conditions and other requirements of any prior or existing assistance agreement, award agreement or Allocation Agreement with the CDFI Fund.

The CDFI Fund reserves the right to reject any NMTC allocation application in the case of a prior Allocatee, if such Applicant has failed to use its prior NMTC allocation(s) in a manner that is generally consistent with the business strategy (including, but not limited to, the proposed product offerings, QALICB type, and markets served) set forth in the allocation application(s) related to such prior allocation(s) or such Applicant has been found by the IRS to have engaged in a transaction or series of transactions designed to achieve a result that is inconsistent with the purposes of IRC § 45D. The CDFI Fund also reserves the right to reject any NMTC allocation application in the case of an Affiliate of the Applicant that is a prior Allocatee and has failed to use its prior NMTC allocation(s) in a manner that is generally consistent with the business strategy set forth in the allocation application(s) related to such prior allocation(s) or has been found by the IRS to have engaged in a transaction or series of transactions designed to achieve a result that is inconsistent with the purposes of IRC § 45D.

The CDFI Fund reserves the right to reject an NMTC allocation application if information (including administrative errors or omission of information) comes to the attention of the CDFI Fund that adversely affects an Applicant's eligibility for an award, adversely affects the CDFI Fund's evaluation or scoring of an application, adversely affects the CDFI Fund's prior determinations of CDE certification, or indicates fraud or mismanagement on the part of an Applicant or the Controlling Entity, if such fraud or mismanagement by the Controlling Entity would hinder the Applicant's ability to perform under the Allocation Agreement. If the CDFI Fund determines that any portion of the application is incorrect in any material respect, the CDFI Fund reserves the right, in its sole discretion, to reject the application.

As a part of the substantive review process, the CDFI Fund may permit the Allocation Recommendation Panel member(s) to request information from Applicants for the sole purpose of obtaining, clarifying or confirming application information or omission of information. In no event shall such contact be construed to permit an Applicant to change any element of its application. At this point in the process, an Applicant may be required to submit additional information about its application in order to assist the CDFI Fund with its final evaluation process. If the Applicant (or the Controlling Entity or any Affiliate) has previously been awarded an NMTC allocation, the CDFI Fund may also request information on the use of those NMTC allocations, to the extent that this information has not already been reported to the CDFI Fund. Such requests must be responded to within the time parameters set by the CDFI Fund. The selecting official(s) will make a final allocation determination based on an Applicant's file, including, without limitation, eligibility under IRC§ 45D, the reviewers' scores and the amount of allocation authority available.

In the case of Applicants (or the Controlling Entity, or Affiliates) that are regulated or receive oversight by the Federal government or a State agency (or comparable entity), the CDFI Fund may request additional information from the Applicant regarding Assurances and Certifications or other information about the ability of the Applicant to effectively perform under the Allocation Agreement. The Allocation Recommendation Panel or selecting official(s) reserve(s) the right to consult with and take into consideration the views of the appropriate Federal or State banking and other regulatory agencies. The CDFI Fund reserves the right to reject any NMTC Allocation Application if additional information is obtained that, after further due diligence and in the discretion of the CDFI Fund, would hinder the Applicant's ability to effectively perform under the Allocation Agreement. In the case of Applicants (or Affiliates of Applicants) that are also Small Business Investment Companies, Specialized Small Business Investment Companies or New Markets Venture Capital Companies, the CDFI Fund reserves the right to consult with and take into consideration the views of the Small Business Administration.

The CDFI Fund reserves the right to conduct additional due diligence, as determined reasonable and appropriate by the CDFI Fund, in its sole discretion, related to the Applicant, Affiliates, the Applicant's Controlling Entity and the officers, directors, owners, partners and key employees of each. This includes the right to consult with the IRS if the Applicant (or the Controlling Entity, or Affiliates) has previously been awarded an NMTC allocation.

Each Applicant will be informed of the CDFI Fund's award decision through an electronic notification whether selected for an allocation or not selected for an allocation, which may be for reasons of application incompleteness, ineligibility or substantive issues. All Applicants that are not selected for an allocation based on substantive issues will likely be given the opportunity to receive feedback on their applications. This feedback will be provided in a format and within a timeframe to be determined by the CDFI Fund, based on available resources.

The CDFI Fund further reserves the right to change its eligibility and evaluation criteria and procedures, if the CDFI Fund deems it appropriate. If said changes materially affect the CDFI Fund's award decisions, the CDFI Fund will provide information regarding the changes through the CDFI Fund's Web site.

There is no right to appeal the CDFI Fund's NMTC allocation decisions. The CDFI Fund's NMTC allocation decisions are final.

VI. Award Administration Information

A. *Allocation Award Compliance.*

1. *Failure to meet reporting requirements:* If an Allocatee, or an Affiliate of an Allocatee, is a prior CDFI Fund award recipient or Allocatee under any CDFI Fund program and is not current on the reporting requirements set forth in the previously executed assistance, allocation, or award agreement(s), as of the date of the NOAA or thereafter, the CDFI Fund reserves the right, in its sole discretion, to reject the application, delay entering into an Allocation Agreement, and/or impose limitations on an Allocatee's ability to issue QEIs to investors until said prior award recipient or Allocatee is current on the reporting requirements in the previously executed assistance, allocation, or award agreement(s). Please note that the automated systems the CDFI Fund uses for receipt of reports submitted electronically typically acknowledges only a report's receipt; such an acknowledgment does not warrant that the report received was complete and therefore met reporting requirements. If said prior award recipient or Allocatee is unable to meet this requirement within the timeframe set by the CDFI Fund, the CDFI Fund reserves the right, in its sole discretion, to terminate and rescind the allocation made under this NOAA.

2. *Pending determination of noncompliance or default:* If an Allocatee is a prior award recipient or Allocatee under any CDFI Fund program and if: (i) It has submitted reports to the CDFI Fund that demonstrate potential noncompliance with or a default under a previous assistance, award, or Allocation Agreement; and (ii) the CDFI Fund has yet to make a final determination as to whether the entity is in noncompliance with or default under its previous assistance, award, or Allocation Agreement, the CDFI Fund reserves the right, in its sole discretion, to delay entering into an Allocation Agreement and/or to impose limitations on the Allocatee's ability to issue Qualified Equity Investments to investors, pending final determination of whether the entity is in noncompliance or default, and determination of remedies, if applicable, in the sole determination of the CDFI Fund. Further, if an Affiliate of an Allocatee is a prior CDFI Fund award recipient or Allocatee and if such entity: (i) Has submitted reports to the CDFI Fund that demonstrate potential noncompliance/default under a previous assistance, award, or Allocation Agreement; and (ii) the CDFI Fund has yet to make a final determination as to whether the entity is in noncompliance/default under its previous assistance, award, or Allocation Agreement, the CDFI Fund reserves the right, in its sole discretion, to delay entering into an Allocation Agreement and/or to impose limitations on the Allocatee's ability to issue QEIs to investors, pending final determination of whether the entity is in noncompliance or default, and determination of remedies, if applicable, in the sole determination of the CDFI Fund. If the prior award recipient or Allocatee in question is unable to satisfactorily resolve the issues of noncompliance, in the sole determination of the CDFI Fund, the CDFI Fund reserves the right, in its sole discretion, to terminate and rescind the award notification made under this NOAA.

3. *Default status:* If prior to entering into an Allocation Agreement through this NOAA: (i) The CDFI Fund has made a determination that an Allocatee that is a prior CDFI Fund award recipient or Allocatee under any CDFI Fund program is in default of a previously executed assistance, allocation, or assistance agreement(s); (ii) the CDFI Fund has provided written notification of such determination to such organization; and (iii) the anticipated date for entering into an Allocation Agreement is within a period of time specified in such notification throughout which any new award, allocation, or assistance is prohibited, the CDFI Fund reserves the right, in its sole discretion, to delay entering into an Allocation Agreement and/or to impose limitations on the Allocatee's ability to issue QEIs to investors, or to terminate and rescind the Notice of Allocation and the allocation made under this NOAA. Furthermore, if prior to entering into an Allocation Agreement through this NOAA: (i) The CDFI Fund has made a determination that an Affiliate of the Allocatee that is a prior CDFI Fund award recipient or Allocatee under any CDFI Fund program is in default of a previously executed assistance, allocation, or award agreement(s); (ii) the CDFI Fund has provided written notification of such determination to such organization; and (iii) the anticipated date for entering into an Allocation Agreement is within a period of time specified in such notification throughout which any new award, allocation, or assistance is prohibited, the CDFI Fund reserves the right, in its sole discretion, to delay entering into an Allocation Agreement and/or to impose limitations on the Allocatee's ability to issue QEIs to investors, or to terminate and rescind the Notice of Allocation and the allocation made under this NOAA.

B. *Allocation Agreement:* Each Applicant that is selected to receive a NMTC allocation (including the Applicant's Subsidiary Allocatees) must enter into an Allocation Agreement with the CDFI Fund. The Allocation Agreement will set forth certain required terms and conditions of the NMTC allocation which may include, but are not limited to, the following: (i) The amount of the awarded NMTC allocation; (ii) the approved uses of the awarded NMTC allocation (*i.e.,* loans to or equity investments in Qualified Active Low-Income Businesses or loans to or equity investments in other CDEs); (iii) the approved service area(s) in which the proceeds of QEIs may be used, including the dollar amount of QLICIs that must be invested in Non-Metropolitan counties; (iv) commitments to specific ''innovative activities'' discussed by the Applicant in its Allocation Application; (v) the time period by which the Applicant may obtain QEIs from investors; (vi) reporting requirements for all Applicants receiving NMTC allocations; and (vii) a requirement to maintain certification as a CDE throughout the term of the Allocation Agreement. If an Applicant has represented in its NMTC allocation application that it intends to invest substantially all of the proceeds from its investors in businesses in which persons unrelated to the Applicant hold a majority equity interest, the Allocation Agreement will contain a covenant whereby said Applicant agrees that it will invest substantially all of said proceeds in businesses in which persons unrelated to the Applicant hold a majority equity interest.

In addition to entering into an Allocation Agreement, each Applicant selected to receive a NMTC allocation must furnish to the CDFI Fund an opinion from its legal counsel or a similar certification, the content of which will be further specified in the Allocation Agreement, to include, among other matters, an opinion that an Applicant (and its Subsidiary Allocatees, if any): (i) Is duly formed and in good standing in the jurisdiction in which it was formed and the jurisdiction(s) in which it operates; (ii) has the authority to enter into the Allocation Agreement and undertake the activities that are specified therein;

(iii) has no pending or threatened litigation that would materially affect its ability to enter into and carry out the activities specified in the Allocation Agreement; and (iv) is not in default of its articles of incorporation, bylaws or other organizational documents, or any agreements with the Federal government.

If an Allocatee identifies Subsidiary Allocatees, the CDFI Fund reserves the right to require an Allocatee to provide supporting documentation evidencing that it Controls such entities prior to entering into an Allocation Agreement with the Allocatee and its Subsidiary Allocatees. The CDFI Fund reserves the right, in its sole discretion, to rescind its allocation award if the Allocatee fails to return the Allocation Agreement, signed by the authorized representative of the Allocatee, and/or provide the CDFI Fund with any other requested documentation, including an approved legal opinion, within the deadlines set by the CDFI Fund.

C. *Fees:* The CDFI Fund reserves the right, in accordance with applicable Federal law and, if authorized, to charge allocation reservation and/or compliance monitoring fees to all entities receiving NMTC allocations. Prior to imposing any such fee, the CDFI Fund will publish additional information concerning the nature and amount of the fee.

D. *Reporting:* The CDFI Fund will collect information, on at least an annual basis from all Applicants that are awarded NMTC allocations and/or are recipients of QLICIs, including such audited financial statements and opinions of counsel as the CDFI Fund deems necessary or desirable, in its sole discretion. The CDFI Fund will require the Applicant to retain information as the CDFI Fund deems necessary or desirable and shall provide such information to the CDFI Fund when requested to monitor each Allocatee's compliance with the provisions of its Allocation Agreement and to assess the impact of the NMTC Program in Low-Income Communities. The CDFI Fund may also provide such information to the IRS in a manner consistent with IRC § 6103 so that the IRS may determine, among other things, whether the Allocatee has used substantially all of the proceeds of each QEI raised through its NMTC allocation to make QLICIs. The Allocation Agreement shall further describe the Allocatee's reporting requirements.

The CDFI Fund reserves the right, in its sole discretion, to modify these reporting requirements if it determines it to be appropriate and necessary; however, such reporting requirements will be modified only after due notice to Allocatees.

VII. Agency Contacts

The CDFI Fund will provide programmatic and information technology support related to the allocation application between the hours of 9:00 a.m. and 5:00 p.m. ET through December 14, 2015. The CDFI Fund will not respond to phone calls or emails concerning the application that are received after 5:00 p.m. ET on December 14, 2015 until after the allocation application deadline of December 16, 2015. Applications and other information regarding the CDFI Fund and its programs may be obtained from the CDFI Fund's Web site at *https://www.cdfifund.gov.* The CDFI Fund will post on its Web site responses to questions of general applicability regarding the NMTC Program.

A. *Information technology support:* Technical support can be obtained by calling (202) 653–0422 or by email at *ithelpdesk@cdfi.treas.gov.* People who have visual or mobility impairments that prevent them from accessing the Low-Income Community maps using the CDFI Fund's Web site should call (202) 653–0422 for assistance. These are not toll free numbers.

B. *Programmatic support:* If you have any questions about the programmatic requirements of this NOAA, contact the CDFI Fund's NMTC Program Manager by email at *cdfihelp@cdfi.treas.gov;* or by telephone at (202) 653–0421. These are not toll-free numbers.

C. *Administrative support:* If you have any questions regarding the administrative requirements of this NOAA, contact the CDFI Fund's NMTC Program Manager by email at *cdfihelp@cdfi.treas.gov,* or by telephone at (202) 653–0421. These are not toll free numbers.

D. *IRS support:* For questions regarding the tax aspects of the NMTC Program, contact Jian Grant and James Holmes, Office of the Associate Chief Counsel (Passthroughs and Special Industries), IRS, by telephone at (202) 317–4137, or by facsimile at (202) 317–6731. These are not toll free numbers. Applicants wishing formal ruling request should see IRS Internal Revenue Bulletin 2015–1, issued January 2, 2015.

VIII. Information Sessions

In connection with this NOAA, the CDFI Fund may conduct one or more information sessions that will be produced in Washington, DC and broadcast over the internet via webcasting as well as telephone conference calls. For further information on these upcoming information sessions, please visit the CDFI Fund's Web site at *https://www.cdfifund.gov.*

Authority: 26 U.S.C. 45D; 31 U.S.C. 321; 26 CFR 1.45D–1.

Dated: October 20, 2015.

Mary Ann Donovan,

Director, Community Development Financial Institutions Fund.

[FR Doc. 2015–26971 Filed 10–22–15; 8:45 am]

BILLING CODE 4810–70–P

DEPARTMENT OF THE TREASURY

Internal Revenue Service

Proposed Collection; Comment Request for Revenue Procedure 2011–4, Revenue Procedure 2011–5, Revenue Procedure 2011–6, and Revenue Procedure 2011–8

AGENCY: Internal Revenue Service (IRS), Treasury.

ACTION: Notice and request for comments.

SUMMARY: The Department of the Treasury, 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 proposed and/or continuing information collections, as required by the Paperwork Reduction Act of 1995, Public Law 104–13 (44 U.S.C. 3506(c)(2)(A)). Currently, the IRS is soliciting comments concerning Revenue Procedure 2011–4 (Letter Rulings), Revenue Procedure 2011–5 (Technical Advice), Revenue Procedure 2011–6 (Determination Letters), and Revenue Procedure 2011–8 (User Fees).

DATES: Written comments should be received on or before December 22, 2015 to be assured of consideration.

ADDRESSES: Direct all written comments to Elaine Christophe, Internal Revenue Service, Room 6129, 1111 Constitution Avenue NW., Washington, DC 20224.

FOR FURTHER INFORMATION CONTACT: Requests for additional information or copies of the revenue procedures should be directed to Allan Hopkins, at Internal Revenue Service, Room 6129, 1111 Constitution Avenue NW., Washington, DC 20224, or through the Internet, at *Allan.M.Hopkins@irs.gov.*

SUPPLEMENTARY INFORMATION:

Title: Revenue Procedure 2011–4 (Letter Rulings), Revenue Procedure 2011–5 (Technical Advice), Revenue Procedure 2011–6 (Determination Letters), and Revenue Procedure 2011–8 (User Fees).

OMB Number: 1545–1520.

Revenue Procedure Number: Revenue Procedure 2011–4, Revenue Procedure 2011–5, Revenue Procedure 2011–6, and Revenue Procedure 2011–8.

Abstract: The information requested in these revenue procedures is required to enable the Office of the Division Commissioner (Tax Exempt and Government Entities) of the Internal Revenue Service to give advice on filing letter ruling, determination letter, and technical advice requests, to process such requests, and to determine the amount of any user fees.

Current Actions: There are no changes being made to these revenue procedures at this time.

Type of Review: Extension of a currently approved collection.

Affected Public: Individuals or households, business or other for-profit organizations, not-for-profit institutions, farms, and state, local or tribal governments.

Estimated Number of Respondents: 83,074.

Estimated Time per Respondent: 2 hours, 8 minutes.

Estimated Total Annual Burden Hours: 178,146.

The following paragraph applies to all of the collections of information covered by this notice:

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless the collection of information displays a valid OMB 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 tax return information are confidential, as required by 26 U.S.C. 6103.

Request for Comments: Comments submitted in response to this notice will be summarized and/or included in the request for OMB approval. All comments will become a matter of public record. Comments are invited on: (a) Whether the collection of information is necessary for the proper performance of the functions of the agency, including whether the information shall have practical utility; (b) the accuracy of the agency's estimate of the burden 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 of information 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.

Approved: October 13, 2015.

Elaine Christophe,

OMB Reports Clearance Officer.

[FR Doc. 2015–26934 Filed 10–22–15; 8:45 am]

BILLING CODE 4830–01–P

DEPARTMENT OF THE TREASURY

Internal Revenue Service

Proposed Collection; Comment Request for Notice 2009–31 and Revenue Procedure 2009–43

AGENCY: Internal Revenue Service (IRS), Treasury.

ACTION: Notice and request for comments.

SUMMARY: The Department of the Treasury, 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 proposed and/or continuing information collections, as required by the Paperwork Reduction Act of 1995, Public Law 104–13 (44 U.S.C. 3506(c)(2)(A)). Currently, the IRS is soliciting comments concerning Notice 2009–31, Election and Notice Procedures for Multiemployer Plans under Sections 204 and 205 of WRERA and Revenue Procedure 2009–43, Revocation of Elections by Multiemployer Plans to Freeze Funded Status under section 204 of WRERA.

DATES: Written comments should be received on or before December 22, 2015 to be assured of consideration.

ADDRESSES: Direct all written comments to Elaine Christophe, Internal Revenue Service, Room 6129, 1111 Constitution Avenue NW., Washington, DC 20224.

FOR FURTHER INFORMATION CONTACT: Requests for additional information or copies of notice should be directed to Allan Hopkins, at Internal Revenue Service, Room 6129, 1111 Constitution Avenue NW., Washington, DC 20224, or through the internet, at *Allan.M.Hopkins@irs.gov.*

SUPPLEMENTARY INFORMATION:

Title: Election and Notice Procedures for Multiemployer Plans under Sections 204 and 205 of WRERA.

OMB Number: 1545–2141.

Notice Number: Notice 2009–31 and Revenue Procedure 2009–43.

Abstract: Notice 2009–31 provides guidance for sponsors of multiemployer defined benefit plans relating to the elections described in sections 204 and 205 of the Worker, Retiree, and Employer Recovery Act of 2008, Public Law 110–458 (WRERA), and on the notice required to be provided if a plan sponsor makes an election under section 204. Revenue Procedure 2009–43 provides follow-up guidance to Notice 2009–31. This new guidance describes procedures for revoking elections under WRERA.

Current Actions: Renewal of OMB approval. There is no change to the paperwork burden previously approved by OMB.

Type of Review: Extension of a currently approved collection.

Affected Public: State, local, or tribal governments.

Estimated Number of Respondents: 1,600.

Estimated Average Time Per Respondent: 1 hour.

Estimated Total Annual Burden Hours: 1,600.

The following paragraph applies to all of the collections of information covered by this notice:

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless the collection of information displays a valid OMB 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 tax return information are confidential, as required by 26 U.S.C. 6103.

Request for Comments: Comments submitted in response to this notice will be summarized and/or included in the request for OMB approval. All comments will become a matter of public record. Comments are invited on: (a) Whether the collection of information is necessary for the proper performance of the functions of the agency, including whether the information shall have practical utility; (b) the accuracy of the agency's estimate of the burden 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 of information 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.

Approved: October 13, 2015.

Elaine Christophe,

IRS Reports Clearance Officer.

[FR Doc. 2015–26933 Filed 10–22–15; 8:45 am]

BILLING CODE 4830–01–P

DEPARTMENT OF THE TREASURY

Internal Revenue Service

Proposed Collection; Comment Request for Forms 5498–QA and 1099–QA

AGENCY: Internal Revenue Service (IRS), Treasury.

ACTION: Notice and request for comments.

SUMMARY: The Department of the Treasury, 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 proposed and/or continuing information collections, as required by the Paperwork Reduction Act of 1995, Public Law 104–13(44 U.S.C. 3506(c)(2)(A)). Currently, the IRS is soliciting comments concerning Form 5498–QA, ABLE Account Contribution Information, and Form 1099–QA, Distributions from ABLE Accounts.

DATES: Written comments should be received on or before December 22, 2015 to be assured of consideration.

ADDRESSES: Direct all written comments to Elaine Christophe, Internal Revenue Service, Room 6129, 1111 Constitution Avenue NW., Washington, DC 20224.

FOR FURTHER INFORMATION CONTACT: Requests for additional information or copies of the form and instructions should be directed to Allan Hopkins, at Internal Revenue Service, Room 6129, 1111 Constitution Avenue NW., Washington, DC 20224, or through the internet, at *Allan.M.Hopkins@irs.gov.*

SUPPLEMENTARY INFORMATION:

Title: ABLE Account Contribution Information; Distributions from ABLE Accounts.

OMB Number: 1545–2262. *Form Numbers:* 5498–QA; 1099–QA.

Abstract: Form 5498–QA, ABLE Account Contributions Information. Public Law 113–295, ABLE Act of 2014 allows individuals and families to set money aside in this special account for the purpose of supporting individuals with disabilities to maintain health, independence, and quality of life, without impacting eligibility for other social service financial assistance programs such as Medicaid. Form 1099–QA allows these individuals and families to draw from the special account.

Current Actions: There are no changes being made to the forms at this time.

Type of Review: Extension of a currently approved collection.

Affected Public: Individuals or households.

Estimated Number of Respondents: 20,000.

Estimated Time per Respondent: 11 min.

Estimated Total Annual Burden Hours: 3,600.

The following paragraph applies to all of the collections of information covered by this notice:

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless the collection of information displays a valid OMB 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 tax return information are confidential, as required by 26 U.S.C. 6103.

Request for Comments: Comments submitted in response to this notice will be summarized and/or included in the request for OMB approval. All comments will become a matter of public record. Comments are invited on: (a) Whether the collection of information is necessary for the proper performance of the functions of the agency, including whether the information shall have practical utility; (b) the accuracy of the agency's estimate of the burden 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 of information 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.

Approved: October 13, 2015.

Elaine Christophe,

IRS Reports Clearance Officer.

[FR Doc. 2015–26921 Filed 10–22–15; 8:45 am]

BILLING CODE 4830–01–P

DEPARTMENT OF THE TREASURY

Proposed Collection; Comment Request; Office of Investment Security

AGENCY: Departmental Offices, Department of the Treasury.

ACTION: Notice and request for comments.

SUMMARY: The Department of the Treasury, 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 continuing information collections, as required by the Paperwork Reduction Act of 1995, Public Law 104–13 (44 U.S.C. 3506(c)(2)(A)). Currently, the Office of Investment Security, within the Department of the Treasury, is soliciting comments concerning the information collection provisions of the Regulations Pertaining to Mergers, Acquisitions and Takeovers by Foreign Persons, 31 CFR 800.402.

DATES: Written comments must be received on or before December 22, 2015 to be assured of consideration.

ADDRESSES: Direct all written comments to Stephen Hanson, Director, Office of Investment Security, Department of the Treasury, 1500 Pennsylvania Avenue NW., Room 5221, Washington, DC 20220; *CFIUS@treasury.gov.*

FOR FURTHER INFORMATION CONTACT: Requests for additional information should be directed to Justin Huff, Office of Investment Security, Department of the Treasury, 1500 Pennsylvania Avenue NW., Washington, DC 20220; (202) 622–6133.

SUPPLEMENTARY INFORMATION:

OMB Number: 1505–0121.

Title: Regulations Pertaining to Mergers, Acquisitions and Takeovers by Foreign Persons.

Abstract: The information request in this proposed collection is contained in 31 CFR 800.402. The information collected under these regulations is used by the Committee on Foreign Investment in the United States (CFIUS), an inter-agency committee chaired by the Secretary of the Treasury and comprised of the Secretaries of State, Defense, Treasury, Commerce, Homeland Security, Energy, and Labor; the Attorney General; the U.S. Trade Representative; and the Directors of National Intelligence and the Office of Science and Technology Policy. CFIUS, on behalf of the President, is authorized under section 721 of the Defense Production Act of 1950 to conduct reviews to determine the effects on the national security of transactions proposed or pending after the date of enactment (August 23, 1988) by or with foreign persons that could result in foreign control of any person engaged in interstate commerce in the United States (''covered transactions'').

Current Actions: Revision of a currently approved collection.

Affected Public: Parties to mergers, acquisitions, and takeovers of U.S businesses.

Estimated Number of Responses: 130.

Estimated Time per Respondent: This varies, depending on individual circumstances, with an average of 116 hours.

Estimated Total Annual Burden Hours: 15,080 hours.

Reason for change: There is an adjustment in the number of respondents from 105 to 130.

Requests for Comments: Comments submitted in response to this notice will be summarized and/or included in the request for OMB approval. All comments will become a matter of public record. Comments are invited on: (a) Whether the collection of information is necessary for the proper performance of the functions of the agency, including whether the information shall have practical utility; (b) the accuracy of the agency's estimate of the burden 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 of information on respondents, including through 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: October 19, 2015.

Dawn D. Wolfgang,

Treasury PRA Clearance Officer.

[FR Doc. 2015–26909 Filed 10–22–15; 8:45 am]

BILLING CODE 4810–25–P

DEPARTMENT OF THE TREASURY

Multiemployer Pension Plan Application To Reduce Benefits

AGENCY: Department of the Treasury.

ACTION: Notice of availability; request for comments.

SUMMARY: The Board of Trustees of the Central States, Southeast and Southwest Areas Pension Plan (Central States Pension Plan), a multiemployer pension plan, has submitted an application to Treasury to reduce benefits under the Central States Pension Plan in accordance with the Multiemployer Pension Reform Act of 2014 (MPRA). The purpose of this notice is to announce that the application submitted by the Board of Trustees of the Central States Pension Plan has been published on the Treasury Web site, and to request public comments on the application from interested parties, including contributing employers, employee organizations, and participants and beneficiaries of the Central States Pension Plan.

DATES: Comments must be received by December 7, 2015.

ADDRESSES: You may submit comments electronically through the Federal eRulemaking Portal at *http://www.regulations.gov,* in accordance with the instructions on that site. Electronic submissions through *www.regulations.gov* are encouraged.

Comments may also be mailed to the Department of the Treasury, MPRA Office, 1500 Pennsylvania Avenue NW., Room 1224, Washington, DC 20220. Attn: Deva Kyle. Comments sent via facsimile and email will not be accepted.

Additional Instructions. All comments received, including attachments and other supporting materials, will be made available to the public. Do not include any personally identifiable information (such as Social Security number, name, address, or other contact information) or any other information in your comment or supporting materials that you do not want publicly disclosed. Treasury will make comments available for public inspection and copying on *www.regulations.gov* or upon request. Comments posted on the Internet can be retrieved by most Internet search engines.

FOR FURTHER INFORMATION CONTACT: For information regarding the application from the Board of Trustees of the Central States Pension Plan, please contact Treasury at (202) 622–1534 (not a toll-free number).

SUPPLEMENTARY INFORMATION: The Multiemployer Pension Reform Act of 2014 (MPRA) amended the Internal Revenue Code to permit a multiemployer plan that is projected to have insufficient funds to reduce pension benefits payable to participants and beneficiaries if certain conditions are satisfied. In order to reduce benefits, the plan sponsor is required to submit an application to the Secretary of the Treasury, which the Department of the Treasury (Treasury), in consultation with the Pension Benefit Guaranty Corporation (PBGC) and the Secretary of Labor, is required to approve or deny.

On September 25, 2015, the Board of Trustees of the Central States Pension Plan submitted an application for approval to reduce benefits under the Central States Pension Plan. As required by the MPRA, that application has been published on Treasury's Web site at *http://www.treasury.gov/services/Pages/central-states-application.aspx.* Treasury is publishing this notice in the **Federal Register**, in consultation with PBGC and the Department of Labor, to solicit public comments on all aspects of the Central States Pension Plan application, including with respect to the interpretation of section 432(e)(9)(D)(vii) of the Internal Revenue Code that is reflected in the application.

Comments are requested from interested parties, including contributing employers, employee organizations, and participants and beneficiaries of the Central States Pension Plan. Consideration will be given to any comments that are timely received by Treasury.

Dated: October 20, 2015.

David R. Pearl,

Executive Secretary, Department of the Treasury.

[FR Doc. 2015–27037 Filed 10–22–15; 8:45 am]

BILLING CODE 4810–25–P

FEDERAL REGISTER

Vol. 80 Friday,

No. 205 October 23, 2015

Part II

Environmental Protection Agency

40 CFR Parts 60, 70, 71, et al.

Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units; Final Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 60, 70, 71, and 98

[EPA–HQ–OAR–2013–0495; EPA–HQ–OAR–2013–0603; FRL–9930–66–OAR]

RIN 2060–AQ91

Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: The Environmental Protection Agency (EPA) is finalizing new source performance standards (NSPS) under Clean Air Act (CAA) section 111(b) that, for the first time, will establish standards for emissions of carbon dioxide (CO_2) for newly constructed, modified, and reconstructed affected fossil fuel-fired electric utility generating units (EGUs). This action establishes separate standards of performance for fossil fuel-fired electric utility steam generating units and fossil fuel-fired stationary combustion turbines. This action also addresses related permitting and reporting issues. In a separate action, under CAA section 111(d), the EPA is issuing final emission guidelines for states to use in developing plans to limit CO_2 emissions from existing fossil fuel-fired EGUs.

DATES: This final rule is effective on October 23, 2015. The incorporation by reference of certain publications listed in the rule is approved by the Director of the Federal Register as of October 23, 2015.

ADDRESSES: The EPA has established dockets for this action under Docket ID No. EPA–HQ–OAR–2013–0495 (Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units) and Docket ID No. EPA–HQ–OAR–2013–0603 (Carbon Pollution Standards for Modified and Reconstructed Stationary Sources: Electric Utility Generating Units). All documents in the dockets 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 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: Dr. Nick Hutson, Energy Strategies Group, Sector Policies and Programs Division (D243–01), U.S. EPA, Research Triangle Park, NC 27711; telephone number (919) 541–2968, facsimile number (919) 541–5450; email address: *hutson.nick@epa.gov* or Mr. Christian Fellner, Energy Strategies Group, Sector Policies and Programs Division (D243–01), U.S. EPA, Research Triangle Park, NC 27711; telephone number (919) 541–4003, facsimile number (919) 541–5450; email address: *fellner.christian@epa.gov.*

SUPPLEMENTARY INFORMATION: *Acronyms.* A number of acronyms and chemical symbols are used in this preamble. While this may not be an exhaustive list, to ease the reading of this preamble and for reference purposes, the following terms and acronyms are defined as follows:

AB Assembly Bill
AEO Annual Energy Outlook
AEP American Electric Power
ANSI American National Standards Institute
ASME American Society of Mechanical Engineers
BACT Best Available Control Technology
BDT Best Demonstrated Technology
BSER Best System of Emission Reduction
Btu/kWh British Thermal Units per Kilowatt-hour
Btu/lb British Thermal Units per Pound
CAA Clean Air Act
CAIR Clean Air Interstate Rule
CBI Confidential Business Information
CCS Carbon Capture and Storage (or Sequestration)
CDX Central Data Exchange
CEDRI Compliance and Emissions Data Reporting Interface
CEMS Continuous Emissions Monitoring System
CFB Circulating Fluidized Bed
CH_4 Methane
CHP Combined Heat and Power
CO_2 Carbon Dioxide
CSAPR Cross-State Air Pollution Rule
DOE Department of Energy
DOT Department of Transportation
ECMPS Emissions Collection and Monitoring Plan System
EERS Energy Efficiency Resource Standards
EGU Electric Generating Unit
EIA Energy Information Administration
EO Executive Order
EOR Enhanced Oil Recovery
EPA Environmental Protection Agency
FB Fluidized Bed
FGD Flue Gas Desulfurization
FOAK First-of-a-kind
FR Federal Register
GHG Greenhouse Gas
GHGRP Greenhouse Gas Reporting Program
GPM Gallons per Minute
GS Geologic Sequestration
GW Gigawatts
H_2 Hydrogen Gas
HAP Hazardous Air Pollutant
HFC Hydrofluorocarbon
HRSG Heat Recovery Steam Generator
IGCC Integrated Gasification Combined Cycle
IPCC Intergovernmental Panel on Climate Change
IPM Integrated Planning Model
IRPs Integrated Resource Plans
kg/MWh Kilogram per Megawatt-hour
kJ/kg Kilojoules per Kilogram
kWh Kilowatt-hour
lb CO_2/MMBtu Pounds of CO_2 per Million British Thermal Unit
lb CO_2/MWh Pounds of CO_2 per Megawatt-hour
lb CO_2/yr Pounds of CO_2 per Year
lb/lb-mole Pounds per Pound-Mole
LCOE Levelized Cost of Electricity
MATS Mercury and Air Toxic Standards
MMBtu/hr Million British Thermal Units per Hour
MRV Monitoring, Reporting, and Verification
MW Megawatt
MWe Megawatt Electrical
MWh Megawatt-hour
MWh-g Megawatt-hour gross
MWh-n Megawatt-hour net
N_2O Nitrous Oxide
NAAQS National Ambient Air Quality Standards
NAICS North American Industry Classification System
NAS National Academy of Sciences
NETL National Energy Technology Laboratory
NGCC Natural Gas Combined Cycle
NOAK n^{th}-of-a-kind
NRC National Research Council
NSPS New Source Performance Standards
NSR New Source Review
NTTAA National Technology Transfer and Advancement Act
O_2 Oxygen Gas
OMB Office of Management and Budget
PC Pulverized Coal
PFC Perfluorocarbon
PM Particulate Matter
$PM_{2.5}$ Fine Particulate Matter
PRA Paperwork Reduction Act
PSD Prevention of Significant Deterioration
PUC Public Utilities Commission
RCRA Resource Conservation and Recovery Act
RFA Regulatory Flexibility Act
RGGI Regional Greenhouse Gas Initiative
RIA Regulatory Impact Analysis
RPS Renewable Portfolio Standard
RTC Response to Comments
RTP Response to Petitions
SBA Small Business Administration
SCC Social Cost of Carbon
SCR Selective Catalytic Reduction
SCPC Supercritical Pulverized Coal
SDWA Safe Drinking Water Act
SF_6 Sulfur Hexafluoride
SIP State Implementation Plan

SNCR Selective Non-Catalytic Reduction
SO_2 Sulfur Dioxide
SSM Startup, Shutdown, and Malfunction
Tg Teragram (one trillion (10^{12}) grams)
Tpy Tons per Year
TSD Technical Support Document
TTN Technology Transfer Network
UIC Underground Injection Control
UMRA Unfunded Mandates Reform Act of 1995
U.S. United States
USDW Underground Source of Drinking Water
USGCRP U.S. Global Change Research Program
VCS Voluntary Consensus Standard
WGS Water Gas Shift
WWW World Wide Web

Organization of This Document. The information presented in this preamble is organized as follows:

I. General Information

A. Executive Summary

1. Purpose of the Regulatory Action

In this final action the EPA is establishing standards that limit greenhouse gas (GHG) emissions from newly constructed, modified, and reconstructed fossil fuel-fired electric utility steam generating units and stationary combustion turbines, following the issuance of proposals for such standards and an accompanying Notice of Data Availability.

On June 25, 2013, in conjunction with the announcement of his Climate Action Plan (CAP), President Obama issued a

Presidential Memorandum directing the EPA to issue a proposal to address carbon pollution from new power plants by September 30, 2013, and to issue ''standards, regulations, or guidelines, as appropriate, which address carbon pollution from modified, reconstructed, and existing power plants.'' Pursuant to authority in section 111(b) of the CAA, on September 20, 2013, the EPA issued proposed carbon pollution standards for newly constructed fossil fuel-fired power plants. The proposal was published in the **Federal Register** on January 8, 2014 (79 FR 1430; ''January 2014 proposal'').[1] In that proposal, the EPA proposed to limit emissions of CO_2 from newly constructed fossil fuel-fired electric utility steam generating units and newly constructed natural gas-fired stationary combustion turbines.

The EPA subsequently issued a Notice of Data Availability (NODA) in which the EPA solicited comment on its initial interpretation of provisions in the Energy Policy Act of 2005 (EPAct05) and associated provisions in the Internal Revenue Code (IRC) and also solicited comment on a companion Technical Support Document (TSD) that addressed these provisions' relationship to the factual record supporting the proposed rule. 79 FR 10750 (February 26, 2014).

On June 2, 2014, the EPA proposed standards of performance, also pursuant to CAA section 111(b), to limit emissions of CO_2 from modified and reconstructed fossil fuel-fired electric utility steam generating units and natural gas-fired stationary combustion turbines. 79 FR 34960 (June 18, 2014) (''June 2014 proposal''). Specifically, the EPA proposed standards of performance for: (1) Modified fossil fuel-fired steam generating units, (2) modified natural gas-fired stationary combustion turbines, (3) reconstructed fossil fuel-fired steam generating units, and (4) reconstructed natural gas-fired stationary combustion turbines.

In this action, the EPA is issuing final standards of performance to limit emissions of GHG pollution manifested as CO_2 from newly constructed, modified, and reconstructed fossil fuel-fired electric utility steam generating units (*i.e.,* utility boilers and integrated gasification combined cycle (IGCC) units) and from newly constructed and reconstructed stationary combustion turbines. Consistent with the requirements of CAA section 111(b), these standards reflect the degree of emission limitation achievable through the application of the best system of emission reduction (BSER) that the EPA has determined has been adequately demonstrated for each type of unit. These final standards are codified in 40 CFR part 60, subpart TTTT, a new subpart specifically created for CAA 111(b) standards of performance for GHG emissions from fossil fuel-fired EGUs.

In a separate action that affects the same source category, the EPA is issuing final emission guidelines under CAA section 111(d) for states to use in developing plans to limit CO_2 emissions from existing fossil fuel-fired EGUs. Pursuant to those guidelines, states must submit plans to the EPA following a schedule set by the guidelines.

The EPA received numerous comments and conducted extensive outreach to stakeholders for this rulemaking. After careful consideration of public comments and input from a variety of stakeholders, the final standards of performance in this action reflect certain changes from the proposals. Comments considered include written comments that were submitted during the public comment period and oral testimony provided during the public hearing for the proposed standards.

2. Summary of Major Provisions and Changes to the Proposed Standards

The BSER determinations and final standards of performance for affected newly constructed, modified, and reconstructed EGUs are summarized in Table 1 and discussed in more detail below. The final standards for new, modified, and reconstructed EGUs apply to sources that commenced construction—or modification or reconstruction, as appropriate—on or after the date of publication of corresponding proposed standards.[2] The final standards for newly constructed fossil fuel-fired EGUs apply to those sources that commenced construction on or after the date of publication of the proposed standards, January 8, 2014. The final standards for modified and reconstructed fossil fuel-fired EGUs apply to those sources that modify or reconstruct on or after the date of publication of the proposed standards, June 18, 2014.

TABLE 1—SUMMARY OF BSER AND FINAL STANDARDS FOR AFFECTED EGUS

Affected EGUs	BSER	Final standards of performance
Newly Constructed Fossil Fuel-Fired Steam Generating Units.	Efficient new supercritical pulverized coal (SCPC) utility boiler implementing partial carbon capture and storage (CCS).	1,400 lb CO_2/MWh-g.
Modified Fossil Fuel-Fired Steam Generating Units.	Most efficient generation at the affected EGU achievable through a combination of best operating practices and equipment upgrades.	Sources making modifications resulting in an increase in CO_2 hourly emissions of more than 10 percent are required to meet a unit-specific emission limit determined by the unit's best historical annual CO_2 emission rate (from 2002 to the date of the modification); the emission limit will be no more stringent than: 1. 1,800 lb CO_2/MWh-g for sources with heat input >2,000 MMBtu/h. 2. 2,000 lb CO_2/MWh-g for sources with heat input ≤2,000 MMBtu/h.
Reconstructed Fossil Fuel-Fired Steam Generating Units.	Most efficient generating technology at the affected source (supercritical steam conditions for the larger; and subcritical conditions for the smaller).	1. Sources with heat input >2,000 MMBtu/h are required to meet an emission limit of 1,800 lb CO_2/MWh-g. 2. Sources with heat input ≤2,000 MMBtu/h are required to meet an emission limit of 2,000 lb CO_2/MWh-g.

[1] The EPA previously proposed performance standards for newly reconstructed fossil fuel-fired EGUs in April 2012 (77 FR 22392). In that action, the EPA proposed standards for steam generating units and natural gas-fired combustion turbines based on a single Best System of Emission Reduction determination. On January 8, 2014, the EPA withdrew that proposal (79 FR 1352).

[2] See CAA section 111(a)(2).

TABLE 1—SUMMARY OF BSER AND FINAL STANDARDS FOR AFFECTED EGUS—Continued

Affected EGUs	BSER	Final standards of performance
Newly Constructed and Reconstructed Fossil Fuel-Fired Stationary Combustion Turbines.	Efficient NGCC technology for base load natural gas-fired units and clean fuels for non-base load and multi-fuel-fired units.[3]	1. 1,000 lb CO_2/MWh-g or 1,030 lb CO_2/MWh-n for base load natural gas-fired units. 2. 120 lb CO_2/MMBtu for non-base load natural gas-fired units. 3. 120 to 160 lb CO_2/MMBtu for multi-fuel-fired units.[4]

a. Fossil Fuel-Fired Electric Utility Steam Generating Units

This action establishes standards of performance for newly constructed fossil fuel-fired steam generating units[5] based on the performance of a new highly efficient SCPC EGU implementing post-combustion partial carbon capture and storage (CCS) technology, which the EPA determines to be the BSER for these sources. After consideration of a wide range of comments, technical input received on the availability, technical feasibility, and cost of CCS implementation, and publicly available information about projects that are implementing or planning to implement CCS, the EPA confirms its proposed determination that CCS technology is available and technically feasible to implement at fossil fuel-fired steam generating units. However, the EPA's final standard reflects the consideration of legitimate concerns regarding the cost to implement available CCS technology on a new steam generating unit. Accordingly, the EPA is finalizing an emission standard for newly constructed fossil fuel-fired steam generating units at 1,400 lb CO_2/MWh-g, a level that is less stringent than the proposed limitation of 1,100 lb CO_2/MWh-g. This final standard reflects our identification of the BSER for such units to be a lower level of partial CCS than we identified as the basis of the proposed standards—one that we conclude better represents the requirement that the BSER be implementable at reasonable cost.

The EPA proposed that the BSER for newly constructed steam generating EGUs was highly efficient new generating technology (*i.e.,* a supercritical utility boiler or IGCC unit) implementing partial CCS technology to achieve CO_2 emission reductions resulting in an emission limit of 1,100 lb CO_2/MWh-g.[6]

The BSER for newly constructed steam generating EGUs in the final rule is very similar to that in the January 2014 proposal. In this final action, the EPA finds that a highly efficient new supercritical pulverized coal (SCPC) utility boiler EGU implementing partial CCS to the degree necessary to achieve an emission of 1,400 lb CO_2/MWh-g is the BSER. Contrary to the January 2014 proposal, the EPA finds that IGCC technology—either with natural gas co-firing or implementing partial CCS—is not part of the BSER, but recognizes that IGCC technology can serve as an alternative method of compliance.

The EPA finds that a highly efficient SCPC implementing partial CCS is the BSER because CCS technology has been demonstrated to be technically feasible and is in use or under construction in various industrial sectors, including the power generation sector. For example, the Boundary Dam Unit #3 CCS project in Saskatchewan, Canada is a full-scale, fully integrated CCS project that is currently operating and is designed to capture more than 90 percent of the CO_2 from the lignite-fired boiler. A newly constructed, highly efficient SCPC utility boiler burning bituminous coal will be able to meet this final standard of performance by capturing and storing approximately 16 percent of the CO_2 produced from the facility. A newly constructed, highly efficient SCPC utility boiler burning subbituminous coal or dried lignite[7] will be able to meet this final standard of performance by capturing and storing approximately 23 percent of the CO_2 produced from the facility. As an alternative compliance option, utilities and project developers will also be able to construct new steam generating units (both utility boilers and IGCC units) that meet the final standard of performance by co-firing with natural gas. This final standard of performance for newly constructed fossil fuel-fired steam generating units provides a clear and achievable path forward for the construction of such sources while addressing GHG emissions and supporting technological innovation. The standard of 1,400 lb CO_2/MWh-g is achievable by fossil fuel-fired steam generating units for all fuel types, under a wide range of conditions, and throughout the United States.

We note that identifying a highly efficient new SCPC EGU implementing partial CCS as the BSER provides a path forward for new fossil fuel-fired steam generation in the current market context. Numerous studies have predicted that few new fossil fuel-fired steam generating units will be constructed in the future. These analyses identify a range of factors unrelated to this rulemaking, including low electricity demand growth, highly competitive natural gas prices, and increases in the supply of renewable energy. The EPA recognizes that, in certain circumstances, there may be interest in building fossil fuel-fired steam generating units despite these market conditions. In particular, utilities and project developers may build new fossil fuel-fired steam generating EGUs in order to achieve or maintain fuel diversity within generating fleets, as a hedge against the possibility of natural gas prices far exceeding projections, or to co-produce both power and chemicals, including capturing CO_2 for use in enhanced oil

[3] The term ''multi-fuel-fired'' refers to a stationary combustion turbine that is physically connected to a natural gas pipeline, but that burns a fuel other than natural gas for 10 percent or more of the unit's heat input capacity during the 12-operating-month compliance period.

[4] The emission standard for combustion turbines co-firing natural gas with other fuels shall be determined at the end of each operating month based on the amount of co-fired natural gas. Units only burning natural gas with other fuels with a relatively consistent chemical composition and an emission factor of 160 lb CO_2/MMBtu or less (*e.g.,* natural gas, distillate oil, etc.) only need to maintain records of the fuels burned at the unit to demonstrate compliance. Units burning fuels with variable chemical composition or with an emission factor greater than 160 lb CO_2/MMBtu (*e.g.,* residual oil) must conduct periodic fuel sampling and testing to determine the overall CO_2 emission rate.

[5] Also referred to as just ''steam generating units'' or as ''utility boilers and IGCC units''. These are units that are covered under 40 CFR part 60, subpart Da for criteria pollutants.

[6] Using the most recent data on partial capture rates to meet an emission standard of 1,100 lb CO_2/MWh-gross, about 35 percent capture would be required at an SCPC unit and about 22 percent capture would be required at an IGCC unit.

[7] For a summary of lignite drying technologies, see ''Techno-economics of modern pre-drying technologies for lignite-fired power plants'' available at *www.iea-coal.org.uk/documents/83436/9095/Techno-economics-of-modern-pre-drying-technologies-for-lignite-fired-power-plants,-CCC/241*; ''Drying the lignite prior to combustion in the boiler is thus an effective way to increase the thermal efficiencies and reduce the CO_2 emissions from lignite-fired power plants.''

recovery (EOR) projects.[8] As regulatory history has shown, identifying a new highly efficient SCPC EGU implementing partial CCS as the BSER in this rule is likely to further boost research and development in CCS technologies, making the implementation even more efficacious and cost-effective, while providing a competitive, low emission future for fossil fuel-fired steam generation.

The EPA is also issuing final standards for steam generating units that implement ''large modifications,'' (*i.e.,* modifications resulting in an increase in hourly CO_2 emissions of more than 10 percent when compared to the source's highest hourly emissions in the previous 5 years).[9] The EPA is not issuing final standards, at this time, for steam generating units that implement ''small modifications'' (*i.e.,* modifications resulting in an increase in hourly CO_2 emissions of less than or equal to 10 percent when compared to the source's highest hourly emissions in the previous 5 years).

The standards of performance for modified steam generating units that make large modifications are based on each affected unit's own best potential performance as the BSER. Specifically, such a modified steam generating unit will be required to meet a unit-specific CO_2 emission limit determined by that unit's best demonstrated historical performance (in the years from 2002 to the time of the modification).[10] The EPA has determined that this standard based on each unit's own best potential performance can be met through a combination of best operating practices and equipment upgrades and that these steps can be implemented cost-effectively at the time when a source is undertaking a large modification. To account for facilities that have already implemented best practices and equipment upgrades, the final rule also specifies that modified facilities will not have to meet an emission standard more stringent than the corresponding standard for reconstructed steam generating units (*i.e.,* 1,800 lb CO_2/MWh-g for units with heat input greater than 2,000 MMBtu/h and 2,000 lb CO_2/MWh-g for units with heat input less than or equal to 2,000 MMBtu/h).

The final standards for steam generating units implementing large modifications are similar to the proposed standards for such units. In the proposal, we suggested that the standard should be based on when the modification is undertaken (*i.e.,* before being subject to requirements under a CAA section 111(d) state plan or after being subject to such a plan). We also suggested that for units that undertake modifications prior to becoming subject to an approved CAA section 111(d) state plan, the standard should be its best historical performance plus an additional two percent reduction. In response to comments on the proposal, we are not finalizing separate standards that are dependent upon when the modification takes place, nor are we finalizing the proposed additional two percentage reduction.

The EPA is not promulgating final standards of performance for, and is withdrawing the proposed standards for steam generating sources that make modifications resulting in an increase of hourly CO_2 emissions of less than or equal to 10 percent (see Section XV of this preamble). As we indicated in the proposal, the EPA has been notified of very few modifications for criteria pollutant emissions from the power sector to which NSPS requirements have applied. As such, we expect that there will be few NSPS modifications for GHG emissions as well. Even so, we also recognize (and we discuss in this preamble) that the power sector is undergoing significant change and realignment in response to a variety of influences and incentives in the industry. We do not have sufficient information at this time, however, to anticipate the types of modifications, if any, that may result from these changes. In particular, we do not have sufficient information about the types of modifications, if any, that would result in increases in CO_2 emissions of 10 percent or less, and what the appropriate standard for such sources would be. Therefore, we conclude that it is prudent to delay issuing standards for sources that undertake small modifications (*i.e.,* those resulting in an increase in CO_2 emissions of less than or equal to 10 percent).

For reconstructed steam generating units, the EPA is finalizing standards based on the performance of the most efficient generating technology for these types of units as the BSER (*i.e.,* reconstructing the boiler if necessary to use steam with higher temperature and pressure, even if the boiler was not originally designed to do so).[11] The emission standard for these sources is 1,800 lb CO_2/MWh-g for large sources, (*i.e.* those with a heat input rating of greater than 2,000 MMBtu/h) or 2,000 lb CO_2/MWh-g for small sources (*i.e.,* those with a heat input rating of 2,000 MMBtu/h or less). The difference in the standards for larger and smaller units is based on greater availability of higher pressure/temperature steam turbines (*e.g.,* supercritical steam turbines) for larger units. The standards can also be met through other non-BSER options, such as natural gas co-firing.

b. Stationary Combustion Turbines

This action also finalizes standards of performance for newly constructed and reconstructed stationary combustion turbines. In the January 2014 proposal for newly constructed EGUs, the EPA proposed that natural gas-fired stationary combustion turbines (*i.e.,* turbines combusting over 90 percent natural gas) would be subject to a standard of performance for CO_2 emissions if they are constructed for the purpose of supplying and actually annually supply to the grid (1) one-third or more of their potential electric output[12] and (2) more than 219,000 MWh,[13] based on a three-year rolling average. We refer to units that operate above the electric sales thresholds as ''base load units,'' and we refer to units that operate below these thresholds as ''non-base load units.''

In the January 2014 proposal for newly constructed combustion turbines, the EPA proposed standards for two subcategories of base load natural gas-fired stationary combustion turbines. The proposed standard for small combustion turbines (units with base load ratings less than or equal to 850 MMBtu/h) was 1,100 lb CO_2/MWh-g. The proposed standard for large combustion turbines (units with base

[8] As the EIA has stated: Policy-related factors, such as environmental regulations and investment or production tax credits for specified generation sources, can also impact investment decisions. Finally, although levelized cost calculations are generally made using an assumed set of capital and operating costs, the inherent uncertainty about future fuel prices and future policies may cause plant owners or investors who finance plants to place a value on *portfolio diversification.* While EIA considers many of these factors in its analysis of technology choice in the electricity sector, these concepts are not included in LCOE or LACE calculations. *http://www.eia.gov/forecasts/aeo/electricity_generation.cfm.*

[9] 40 CFR 60.14(h) provides that no physical change, or change in the method of operation, at an existing electric utility steam generating unit will be treated as a modification provided that such change does not increase the maximum hourly emissions above the maximum hourly emissions achievable at that unit during the 5 years prior to the change.

[10] For the 2002 reporting year the EPA introduced new automated checks in the software that integrated automated quality assurance (QA) checks on the hourly data. Thus, the EPA believes that the data from 2002 and forward are of higher quality.

[11] Steam with higher temperature and pressure has more thermal energy that can be more efficiently converted to electrical energy.

[12] We refer to thresholds related to an EGU's actual annual electrical sales (as a fraction of potential annual output) as ''percentage electric sales criteria.''

[13] We refer to thresholds related to an EGU's actual annual electrical sales in megawatt-hours as ''total electric sales criteria.''

load ratings greater than 850 MMBtu/h) was 1,000 lb CO_2/MWh-g. The EPA did not propose standards for non-base load units.

In the June 2014 proposal for modified and reconstructed combustion turbines, the EPA solicited comment on alternative approaches for establishing applicability and subcategorization criteria, including (1) eliminating the ''constructed for the purpose of supplying'' qualifier for the total electric sales and percentage electric sales criteria, (2) eliminating the 219,000 MWh total electric sales criterion altogether, (3) replacing the fixed percentage electric sales criterion with a variable percentage electric sales criterion (*i.e.,* the sliding-scale approach [14]), and (4) eliminating the proposed small and large subcategories for base load natural gas-fired combustion turbines. These proposed applicability requirements were intended to exclude combustion turbines that are used for the purpose of meeting peak power demand, as opposed to those that are used to meet base load power demand.

In both proposals, the EPA also solicited comment on a broad applicability approach that would include non-base load natural gas-fired units (primarily simple cycle combustion turbines) and multi-fuel-fired units (primarily distillate oil-fired combustion turbines) in the general applicability of subpart TTTT. As part of the broad applicability approach, the EPA solicited comment on imposing ''no emission standard'' or establishing separate numerical limits for these two subcategories.

In this action, the EPA is finalizing a variation of the approaches put forward in the January 2014 proposal for new sources and the June 2014 proposal for modified and reconstructed sources. Based on our review of public comments related to the proposed subcategories for small and large combustion turbines and our additional data analyses, we have determined that there is no need to set two separate standards for different sizes of combustion turbines for base load natural gas-fired combustion turbines. The EPA has determined that all sizes of affected newly constructed and reconstructed stationary combustion turbines can achieve the final standards. For newly constructed and reconstructed base load natural gas-fired stationary combustion turbines, the EPA is finalizing a standard of 1,000 lb CO_2/MWh-g based on efficient natural gas combined cycled (NGCC) technology as the BSER. Alternatively, owners and operators of base load natural gas-fired combustion turbines may elect to comply with a standard based on net output of 1,030 lb CO_2/MWh-n.

The EPA is eliminating the 219,000 MWh total annual electric sales criterion for non-CHP units. In addition, the EPA is finalizing the sliding-scale approach for deriving the unit-specific, percentage electric sales threshold above which a combustion turbine transitions from the subcategory for non-base load units to the subcategory for base load units. For newly constructed and reconstructed non-base load natural gas-fired stationary combustion turbines, the EPA is finalizing the combustion of clean fuels (natural gas with a small allowance for distillate oil) as the BSER with a corresponding heat input-based standard of 120 lb CO_2/MMBtu. This standard of performance will apply to the vast majority of simple cycle combustion turbines. The EPA is finalizing a heat input-based clean fuels standard because we have insufficient information at this time to set a uniform output-based standard that can be achieved by all new and reconstructed non-base load units.

In addition, for newly constructed and reconstructed multi-fuel-fired stationary combustion turbines, the EPA is finalizing an input-based standard of 120 to 160 lb CO_2/MMBtu based on the combustion of clean fuels as the BSER.[15] The EPA has similarly determined that it has insufficient information at this time to set a uniform output-based standard for stationary combustion turbines that operate with significant quantities of a fuel other than natural gas.

We are not promulgating final standards of performance for stationary combustion turbines that make modifications at this time. We are simultaneously withdrawing the proposed standards for modifications (see Section XV of this preamble). As we indicated in the proposal, sources from the power sector have notified the EPA of very few NSPS modifications, and we expect that there will be few NSPS modifications for CO_2 emissions as well. Moreover, our decision to eliminate the subcategories for small and large EGUs and set a single standard of 1,000 lb CO_2/MWh-g has raised questions as to whether smaller existing combustion turbines that undertake a modification can meet this standard. As a result, we have concluded that it is prudent to delay issuing standards for sources that undertake modifications until we can gather more information.

A more detailed discussion of the final standards of performance for stationary combustion turbines, the applicability criteria, and the comments that influenced the final standards is provided in Sections VIII and IX of this preamble.

3. Costs and Benefits

As explained in the regulatory impact analysis (RIA) for this final rule, available data—including utility announcements and Energy Information Administration (EIA) modeling—indicate that, even in the absence of this rule, (i) existing and anticipated economic conditions are such that few, if any, fossil fuel-fired steam-generating EGUs will be built in the foreseeable future, and (ii) utilities and project developers are expected to choose new generation technologies (primarily NGCC) that would meet the final standards and renewable generating sources that are not affected by these final standards. These projections are consistent with utility announcements and EIA modeling that indicate that new units are likely to be NGCC and that any coal-fired steam generating units built between now and 2030 would have CCS, even in the absence of this rule.[16] Therefore, based on the analysis presented in Chapter 4 of the RIA, the EPA projects that this final rule will result in negligible CO_2 emission changes, quantified benefits, and costs by 2022 as a result of the performance standards for newly constructed EGUs.[17] However, as noted earlier, for a variety of reasons, some companies may consider coal-fired steam generating units that the modeling does not anticipate. Thus, in Chapter 5 of the RIA, we also present an analysis of the project-level costs of a newly constructed coal-fired steam generating unit with partial CCS that meets the requirements of this final rule alongside the project-level costs of a newly constructed coal-fired unit without CCS. This analysis indicates that the

[14] The sliding-scale approach determines a unit-specific percentage electric sales threshold equivalent to a unit's net design efficiency (the maximum value is capped at 50 percent).

[15] Combustion turbines co-firing natural gas with other fuels shall determine fuel-based site-specific standards at the end of each operating month. The site-specific standards depend on the amount of co-fired natural gas.

[16] The EPA's Integrated Planning Model (IPM) projects no new non-compliant coal (*i.e.,* newly constructed coal-fired plants that do not meet the final standard of performance) throughout the model horizon of 2030 (there is a small amount of new coal with CCS that is hardwired into the modelling, consistent with EIA assumptions to represent units already under construction or under development).

[17] Conditions in the analysis year of 2022 are represented by a model year of 2020.

quantified benefits of the standards of performance would exceed their costs under a range of assumptions.

As explained in the RIA and further below, the EPA has been notified of few power sector NSPS modifications or reconstructions. Based on that experience, the EPA expects that few EGUs will trigger either the modification or the reconstruction provisions that we are finalizing in this action. In Chapter 6 of the RIA, we discuss factors that limit our ability to quantify the costs and benefits of the standards for modified and reconstructed sources.

B. Does this action apply to me?

The entities potentially affected by the standards are shown in Table 2 below.

TABLE 2—POTENTIALLY AFFECTED ENTITIES [a]

Category	NAICS code	Examples of potentially affected entities
Industry	221112	Fossil fuel electric power generating units.
Federal Government	[b]221112	Fossil fuel electric power generating units owned by the federal government.
State/Local Government	[b]221112	Fossil fuel electric power generating units owned by municipalities.
Tribal Government	921150	Fossil fuel electric power generating units in Indian Country.

[a] Includes NAICS categories for source categories that own and operate electric power generating units (including boilers and stationary combined cycle combustion turbines).

[b] Federal, state, or local government-owned and operated establishments are classified according to the activity in which they are engaged.

This table is not intended to be exhaustive, but rather to provide a guide for readers regarding entities likely to be affected by this action. To determine whether your facility, company, business, organization, etc., would be regulated by this action, refer to Section III of this preamble for more information and examine the applicability criteria in 40 CFR 60.1 (General Provisions) and § 60.550840 of subpart TTTT (Standards of Performance for Greenhouse Gas Emissions for Electric Utility Generating Units). 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).

C. Where can I get a copy of this document?

In addition to being available in the docket, an electronic copy of this final action will also be available on the Worldwide Web (WWW). Following signature, a copy of this final action will be posted at the following address: *http://www2.epa.gov/carbon-pollution-standards.*

D. Judicial Review

Under section 307(b)(1) of the CAA, judicial review of this final rule is available only by filing a petition for review in the U.S. Court of Appeals for the District of Columbia Circuit by December 22, 2015. Moreover, under section 307(b)(2) of the CAA, the requirements established by this final rule may not be challenged separately in any civil or criminal proceedings brought by the EPA to enforce these 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 mandating the EPA to convene a proceeding for reconsideration if the person raising an objection can demonstrate 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, Ariel Rios 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.

E. How is this preamble organized?

This action presents the EPA's final standards of performance for newly constructed, modified, and reconstructed fossil fuel-fired electric utility steam generating units and newly constructed and reconstructed stationary combustion turbines. Section II provides background information on climate change impacts from GHG emissions, GHG emissions from fossil fuel-fired EGUs, the utility power sector, the statutory and regulatory background relating to CAA section 111(b), EPA actions prior to this final action, and public comments regarding the proposed actions. Section III explains the EPA's authority to regulate CO_2 and EGUs, identifies affected EGUs, and describes the source categories. Section IV provides a summary of the final standards for newly constructed, modified, and reconstructed fossil fuel-fired steam generating units. Sections V through VII present the rationale for the final standards for newly constructed, modified, and reconstructed steam generating units, respectively. Sections VIII and IX provide a summary of the final standards for stationary combustion turbines and present the rationale for the final standards for newly constructed and reconstructed combustion turbines, respectively. Section X provides a summary of other final requirements for newly constructed, modified, and reconstructed fossil fuel-fired steam generating units and stationary combustion turbines. Section XI addresses the consistency of the respective BSER determinations in these rules and under the emission guidelines issued separately under CAA section 111(d). Interactions with other EPA programs and rules are described in Section XII. Projected impacts of the final action are then described in Section XIII, followed by a discussion of statutory and executive order reviews in Section XIV. Section XV addresses the withdrawal of the proposed standards for steam generating EGUs that make modifications resulting in an increase of hourly CO_2 emissions of less than or equal to 10 percent and the proposed standards for modified stationary combustion turbines. The statutory authority for this action is provided in Section XVI. We address major comments throughout this preamble and in greater detail in an accompanying response-to-comments document located in the docket.

II. Background

In this section, we discuss climate change impacts from GHG emissions, both on public health and public welfare. We also present information about GHG emissions from fossil fuel-fired EGUs and describe the utility power sector and its changing structure. We then summarize the statutory and regulatory background relevant to this final rulemaking. In addition, we provide background information on the EPA's January 8, 2014 proposed carbon pollution standards for newly constructed fossil fuel-fired EGUs, the June 18, 2014 proposed carbon pollution standards for modified and reconstructed EGUs, and other actions associated with this final rulemaking. We close this section with a general discussion of comments and stakeholder input that the EPA received prior to issuing this final rulemaking.

A. Climate Change Impacts From GHG Emissions

According to the National Research Council, ''Emissions of CO_2 from the burning of fossil fuels have ushered in a new epoch where human activities will largely determine the evolution of Earth's climate. Because CO_2 in the atmosphere is long lived, it can effectively lock Earth and future generations into a range of impacts, some of which could become very severe. Therefore, emission reduction choices made today matter in determining impacts experienced not just over the next few decades, but in the coming centuries and millennia.'' [18]

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).[19] 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.

1. 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.

2. 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 flood 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.

3. 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 (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), the 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 III.A of the 2009 Endangerment Finding, which was to rely primarily upon the major assessments by the USGCRP, the IPCC, and the NRC of the National Academies 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

[18] National Research Council, Climate Stabilization Targets, p. 3.

[19] ''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'').

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 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.'' [20] 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.[21] In fact, that assessment stated that ''the magnitude and rate of the present greenhouse gas 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.'' [22] Because of these unprecedented changes, several assessments state that we may be approaching critical, poorly understood thresholds. As stated in the assessment, ''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 irreversible impacts that are 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 any given concentration of CO_2 reached 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

[20] 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.

[21] National Research Council, Understanding Earth's Deep Past, p. 1.

[22] *Id.*, p. 138.

average global temperatures by the end of the century will likely be 2.6 degrees Celsius (°C) to 4.8 °C (4.7 to 8.6 degrees Fahrenheit (°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 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 was 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 CO_2 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,'' [23] 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.'' [24] 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 CO_2 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 that 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 U.S. 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.'' [25] 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.'' [26]

CO_2 in particular has unique impacts on ocean ecosystems. The NRC *Climate Stabilization Targets* assessment found that coral bleaching will increase due both to warming and ocean acidification. Ocean surface waters have already become 30 percent more acidic over the past 250 years due to absorption of CO_2 from the atmosphere. According to the NCA3, this acidification will reduce the ability of organisms such as corals, krill, oysters, clams, and crabs to survive, grow, and reproduce. The NRC *Understanding Earth's Deep Past* assessment notes that four of the five major coral reef crises of the past 500 million years were caused by acidification and warming that followed GHG increases of similar magnitude to the emissions increases expected over the next hundred years. The NRC *Abrupt Impacts* assessment specifically highlighted similarities between the projections for future acidification and warming and the extinction at the end of the Permian which resulted in the loss of an estimated 90 percent of known species. Similarly, the NRC *Ocean Acidification* assessment finds that ''[t]he chemistry of the ocean is changing at an unprecedented rate and magnitude due to anthropogenic CO_2 emissions; the rate of change exceeds any known to have occurred for at least the past

[23] NRC, 2011: *National Security Implications of Climate Change for U.S. Naval Forces.* The National Academies Press, p. 28.

[24] 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.

[25] 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.

[26] 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.

hundreds of thousands of years.'' [27] The assessment notes that the full range of consequences is still unknown, but the risks ''threaten coral reefs, fisheries, protected species, and other natural resources of value to society.'' [28]

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 percent probability) that human influence was the dominant cause of the observed warming since the mid-20th century, and likely (>66 percent 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 °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 have 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 has increased substantially in recent years, to 215 gigatons per year and 147 gigatons per year respectively, since 2002. For context, 360 gigatons of ice melt is sufficient to cause global sea levels to rise 1 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. In 2009, the year of the Endangerment Finding, the average concentration of CO_2 as measured on top of Mauna Loa was 387 parts per million, far above preindustrial concentrations of about 280 parts per million.[29] The average concentration in 2013, the last full year before this rule was proposed, was 396 parts per million. The average concentration in 2014 was 399 parts per million. And the monthly concentration in April of 2014 was 401 parts per million, the first time a monthly average has exceeded 400 parts per million since record keeping began at Mauna Loa in 1958, and for at least the past 800,000 years based on ice core records.[30] 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.[31] 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.[32] 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.'' [33] 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 greenhouse gases is on the higher end of the estimated range.
- Waiting for unacceptable impacts to occur before taking action is imprudent because the effects of greenhouse gas 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.

4. Observed and Projected U.S. Regional Changes

The NCA3 assessed the climate impacts in eight regions of the United States, noting that changes in physical climate parameters such as temperatures, precipitation, and sea ice retreat were already having impacts on forests, water supplies, ecosystems, flooding, heat waves, and air quality. Moreover, the NCA3 found that future warming is projected to be much larger than recent observed variations in temperature, with precipitation likely to increase in the northern states, decrease in the southern states, and with the heaviest precipitation events projected to increase everywhere.

In the Northeast, temperatures increased almost 2 °F from 1895 to 2011, precipitation increased by about 5 inches (10 percent), and sea level rise of about a foot has led to an increase in coastal flooding. The 70 percent increase in the amount of rainfall falling in the 1 percent of the most intense events is a larger increase in extreme precipitation than experienced in any other U.S. region.

In the future, if emissions continue increasing, the Northeast is expected to experience 4.5 to 10 °F of warming by

[27] NRC, 2010: *Ocean Acidification: A National Strategy to Meet the Challenges of a Changing Ocean.* The National Academies Press, p. 5.

[28] *Id.*

[29] *ftp://aftp.cmdl.noaa.gov/products/trends/co2/co2_annmean_mlo.txt.*

[30] *http://www.esrl.noaa.gov/gmd/ccgg/trends/.*

[31] Blunden, J., and D. S. Arndt, Eds., 2014: State of the Climate in 2013. Bull. Amer. Meteor. Soc., 95 (7), S1–S238.

[32] *http://www.ncdc.noaa.gov/sotc/global/2014/13.*

[33] NRC, 2011: *America's Climate Choices,* The National Academies Press.

the 2080s. This will lead to more heat waves, coastal and river flooding, and intense precipitation events. The southern portion of the region is projected to see 60 additional days per year above 90 °F by mid-century. Sea levels in the Northeast are expected to increase faster than the global average because of subsidence, and changing ocean currents may further increase the rate of sea level rise. Specific vulnerabilities highlighted by the NCA include large urban populations particularly vulnerable to climate-related heat waves and poor air quality episodes, prevalence of climate sensitive vector-borne diseases like Lyme and West Nile Virus, usage of combined sewer systems that may lead to untreated water being released into local water bodies after climate-related heavy precipitation events, and 1.6 million people living within the 100-year coastal flood zone who are expected to experience more frequent floods due to sea level rise and tropical-storm induced storm-surge. The NCA also highlighted infrastructure vulnerable to inundation in coastal metropolitan areas, potential agricultural impacts from increased rain in the spring delaying planting or damaging crops or increased heat in the summer leading to decreased yields and increased water demand, and shifts in ecosystems leading to declines in iconic species in some regions, such as cod and lobster south of Cape Cod.

In the Southeast, average annual temperature during the last century cycled between warm and cool periods. A warm peak occurred during the 1930s and 1940s, followed by a cool period, and temperatures then increased again from 1970 to the present by an average of 2 °F. There have been increasing numbers of days above 95 °F and nights above 75 °F, and decreasing numbers of extremely cold days since 1970. Daily and five-day rainfall intensities have also increased, and summers have been either increasingly dry or extremely wet. Louisiana has already lost 1,880 square miles of land in the last 80 years due to sea level rise and other contributing factors.

The Southeast is exceptionally vulnerable to sea level rise, extreme heat events, hurricanes, and decreased water availability. Major consequences of further warming include significant increases in the number of hot days (95 °F or above) and decreases in freezing events, as well as exacerbated ground-level ozone in urban areas. Although projected warming for some parts of the region by the year 2100 is generally smaller than for other regions of the United States, projected warming for interior states of the region is larger than coastal regions by 1 °F to 2 °F. Projections further suggest that there will be fewer tropical storms globally, but that they will be more intense, with more Category 4 and 5 storms. The NCA identified New Orleans, Miami, Tampa, Charleston, and Virginia Beach as being specific cities that are at risk due to sea level rise, with homes and infrastructure increasingly prone to flooding. Additional impacts of sea level rise are expected for coastal highways, wetlands, fresh water supplies, and energy infrastructure.

In the Northwest, temperatures increased by about 1.3 °F between 1895 and 2011. A small average increase in precipitation was observed over this time period. However, warming temperatures have caused increased rainfall relative to snowfall, which has altered water availability from snowpack across parts of the region. Snowpack in the Northwest is an important freshwater source for the region. More precipitation falling as rain instead of snow has reduced the snowpack, and warmer springs have corresponded to earlier snowpack melting and reduced streamflows during summer months. Drier conditions have increased the extent of wildfires in the region.

Average annual temperatures are projected to increase by 3.3 °F to 9.7 °F by the end of the century (depending on future global GHG emissions), with the greatest warming expected during the summer. Continued increases in global GHG emissions are projected to result in up to a 30 percent decrease in summer precipitation. Earlier snowpack melt and lower summer stream flows are expected by the end of the century and will affect drinking water supplies, agriculture, ecosystems, and hydropower production. Warmer waters are expected to increase disease and mortality in important fish species, including Chinook and sockeye salmon. Ocean acidification also threatens species such as oysters, with the Northwest coastal waters already being some of the most acidified worldwide due to coastal upwelling and other local factors. Forest pests are expected to spread and wildfires to burn larger areas. Other high-elevation ecosystems are projected to be lost because they can no longer survive the climatic conditions. Low lying coastal areas, including the cities of Seattle and Olympia, will experience heightened risks of sea level rise, erosion, seawater inundation and damage to infrastructure and coastal ecosystems.

In Alaska, temperatures have changed faster than anywhere else in the United States. Annual temperatures increased by about 3 °F in the past 60 years. Warming in the winter has been even greater, rising by an average of 6 °F. Arctic sea ice is thinning and shrinking in area, with the summer minimum ice extent now covering only half the area it did when satellite records began in 1979. Glaciers in Alaska are melting at some of the fastest rates on Earth. Permafrost soils are also warming and beginning to thaw. Drier conditions have contributed to more large wildfires in the last 10 years than in any previous decade since the 1940s, when recordkeeping began. Climate change impacts are harming the health, safety, and livelihoods of Native Alaskan communities.

By the end of this century, continued increases in GHG emissions are expected to increase temperatures by 10 to 12 °F in the northernmost parts of Alaska, by 8 to 10 °F in the interior, and by 6 to 8 °F across the rest of the state. These increases will exacerbate ongoing arctic sea ice loss, glacial melt, permafrost thaw and increased wildfire, and threaten humans, ecosystems, and infrastructure. Precipitation is expected to increase to varying degrees across the state. However, warmer air temperatures and a longer growing season are expected to result in drier conditions. Native Alaskans are expected to experience declines in economically, nutritionally, and culturally important wildlife and plant species. Health threats will also increase, including loss of clean water, saltwater intrusion, sewage contamination from thawing permafrost, and northward extension of diseases. Wildfires will increasingly pose threats to human health as a result of smoke and direct contact. Areas underlain by ice-rich permafrost across the state are likely to experience ground subsidence and extensive damage to infrastructure as the permafrost thaws. Important ecosystems will continue to be affected. Surface waters and wetlands that are drying provide breeding habitat for millions of waterfowl and shorebirds that winter in the lower 48 states. Warmer ocean temperatures, acidification, and declining sea ice will contribute to changes in the location and availability of commercially and culturally important marine fish.

In the Southwest, temperatures are now about 2 °F higher than the past century, and are already the warmest that region has experienced in at least 600 years. The NCA notes that there is evidence that climate change-induced warming on top of recent drought has influenced tree mortality, wildfire frequency and area, and forest insect outbreaks. Sea levels have risen about 7 or 8 inches in this region, contributing to inundation of Highway 101 and back up of seawater into sewage systems in the San Francisco area.

Projections indicate that the Southwest will warm an additional 5.5 to 9.5 °F over the next century if emissions continue to increase. Winter snowpack in the Southwest is projected to decline (consistent with the record lows from this past winter), reducing the reliability of surface water supplies for cities, agriculture, cooling for power plants, and ecosystems. Sea level rise along the California coast will worsen coastal erosion, increase flooding risk for coastal highways, bridges, and low-lying airports, pose a threat to groundwater supplies in coastal cities such as Los Angeles, and increase vulnerability to floods for hundreds of thousands of residents in coastal areas. Climate change will also have impacts on the high-value specialty crops grown in the region as a drier climate will increase demands for irrigation, more frequent heat waves will reduce yields, and decreased winter chills may impair fruit and nut production for trees in California. Increased drought, higher temperatures, and bark beetle outbreaks are likely to contribute to continued increases in wildfires. The highly urbanized population of the Southwest is vulnerable to heat waves and water supply disruptions, which can be exacerbated in cases where high use of air conditioning triggers energy system failures.

The rate of warming in the Midwest has markedly accelerated over the past few decades. Temperatures rose by more than 1.5 °F from 1900 to 2010, but between 1980 and 2010, the rate of warming was three times faster than from 1900 through 2010. Precipitation generally increased over the last century, with much of the increase driven by intensification of the heaviest rainfalls. Several types of extreme weather events in the Midwest (*e.g.,* heat waves and flooding) have already increased in frequency and/or intensity due to climate change.

In the future, if emissions continue increasing, the Midwest is expected to experience 5.6 to 8.5 °F of warming by the 2080s, leading to more heat waves. Though projections of changes in total precipitation vary across the regions, more precipitation is expected to fall in the form of heavy downpours across the entire region, leading to an increase in flooding. Specific vulnerabilities highlighted by the NCA include long-term decreases in agricultural productivity, changes in the composition of the region's forests, increased public health threats from heat waves and degraded air and water quality, negative impacts on transportation and other infrastructure associated with extreme rainfall events and flooding, and risks to the Great Lakes including shifts in invasive species, increases in harmful algal blooms, and declining beach health.

High temperatures (more than 100 °F in the Southern Plains and more than 95 °F in the Northern Plains) are projected to occur much more frequently by mid-century. Increases in extreme heat will increase heat stress for residents, energy demand for air conditioning, and water losses. North Dakota's increase in annual temperatures over the past 130 years is the fastest in the contiguous U.S., mainly driven by warming winters. Specific vulnerabilities highlighted by the NCA include increased demand for water and energy, changes to crop-growth cycles and agricultural practices, and negative impacts on local plant and animal species from habitat fragmentation, wildfires, and changes in the timing of flowering or pest patterns. Communities that are already the most vulnerable to weather and climate extremes will be stressed even further by more frequent extreme events occurring within an already highly variable climate system.

In Hawaii, other Pacific islands, and the Caribbean, rising air and ocean temperatures, shifting rainfall patterns, changing frequencies and intensities of storms and drought, decreasing baseflow in streams, rising sea levels, and changing ocean chemistry will affect ecosystems on land and in the oceans, as well as local communities, livelihoods, and cultures. Low islands are particularly at risk.

Rising sea levels, coupled with high water levels caused by tropical and extra-tropical storms, will incrementally increase coastal flooding and erosion, damaging coastal ecosystems, infrastructure, and agriculture, and negatively affecting tourism. Ocean temperatures in the Pacific region exhibit strong year-to-year and decadal fluctuations, but since the 1950s, they have exhibited a warming trend, with temperatures from the surface to a depth of 660 feet rising by as much as 3.6 °F. As a result of current sea level rise, the coastline of Puerto Rico around Rincón is being eroded at a rate of 3.3 feet per year. Freshwater supplies are already constrained and will become more limited on many islands. Saltwater intrusion associated with sea level rise will reduce the quantity and quality of freshwater in coastal aquifers, especially on low islands. In areas where precipitation does not increase, freshwater supplies will be adversely affected as air temperature rises.

Warmer oceans are leading to increased coral bleaching events and disease outbreaks in coral reefs, as well as changed distribution patterns of tuna fisheries. Ocean acidification will reduce coral growth and health. Warming and acidification, combined with existing stresses, will strongly affect coral-reef fish communities. For Hawaii and the Pacific islands, future sea surface temperatures are projected to increase 2.3 °F by 2055 and 4.7 °F by 2090 under a scenario that assumes continued increases in emissions. Ocean acidification is also taking place in the region, which adds to ecosystem stress from increasing temperatures. Ocean acidity has increased by about 30 percent since the pre-industrial era and is projected to further increase by 37 percent to 50 percent from present levels by 2100.

The NCA also discussed impacts that occur along the coasts and in the oceans adjacent to many regions, and noted that other impacts occur across regions and landscapes in ways that do not follow political boundaries.

B. GHG Emissions From Fossil Fuel-Fired EGUs

Fossil fuel-fired EGUs are by far the largest emitters of GHGs among stationary sources in the U.S., primarily in the form of CO_2. Among fossil fuel-fired EGUs, coal-fired units are by far the largest emitters. This section describes the amounts of these emissions and places these amounts in the context of the U.S. Inventory of Greenhouse Gas Emissions and Sinks [34] (the U.S. GHG Inventory).

The EPA implements a separate program under 40 CFR part 98 called the Greenhouse Gas Reporting Program [35] (GHGRP) that requires emitting facilities that emit over certain threshold amounts of GHGs to report their emissions to the EPA annually. Using data from the GHGRP, this section also places emissions from fossil fuel-fired EGUs in the context of the total emissions reported to the GHGRP from facilities in the other largest-emitting industries.

The EPA prepares the official U.S. GHG Inventory to comply with commitments under the United Nations Framework Convention on Climate

[34] "Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2013", Report EPA 430–R–15–004, United States Environmental Protection Agency, April 15, 2015. *http://epa.gov/climatechange/ghgemissions/usinventoryreport.html.*

[35] U.S. EPA Greenhouse Gas Reporting Program Dataset, see *http://www.epa.gov/ghgreporting/ghgdata/reportingdatasets.html.*

Change (UNFCCC). This inventory, which includes recent trends, is organized by industrial sector. It provides the information in Table 3 below, which presents total U.S. anthropogenic emissions and sinks[36] of GHGs, including CO_2 emissions, for the years 1990, 2005 and 2013.

TABLE 3—U.S. GHG EMISSIONS AND SINKS BY SECTOR (MILLION METRIC TONS CARBON DIOXIDE EQUIVALENT (MMT CO_2e))[37 38]

Sector	1990	2005	2013
Energy[39]	5,290.5	6,273.6	5,636.6
Industrial Processes and Product Use	342.1	367.4	359.1
Agriculture	448.7	494.5	515.7
Land Use, Land-Use Change and Forestry	13.8	25.5	23.3
Waste	206.0	189.2	138.3
Total Emissions	6,301.1	7,350.2	6,673.0
Land Use, Land-Use Change and Forestry (Sinks)	(775.8)	(911.9)	(881.7)
Net Emissions (Sources and Sinks)	5,525.2	6,438.3	5,791.2

Total fossil energy-related CO_2 emissions (including both stationary and mobile sources) are the largest contributor to total U.S. GHG emissions, representing 77.3 percent of total 2013 GHG emissions.[40] In 2013, fossil fuel combustion by the utility power sector—entities that burn fossil fuel and whose primary business is the generation of electricity—accounted for 38.3 percent of all energy-related CO_2 emissions.[41] Table 4 below presents total CO_2 emissions from fossil fuel-fired EGUs, for years 1990, 2005, and 2013.

TABLE 4—U.S. GHG EMISSIONS FROM GENERATION OF ELECTRICITY FROM COMBUSTION OF FOSSIL FUELS (MMT CO_2)[42]

GHG emissions	1990	2005	2013
Total CO_2 from fossil fuel-fired EGUs	1,820.8	2,400.9	2,039.8
—from coal	1,547.6	1,983.8	1,575.0
—from natural gas	175.3	318.8	441.9
—from petroleum	97.5	97.9	22.4

In addition to preparing the official U.S. GHG Inventory to present comprehensive total U.S. GHG emissions and comply with commitments under the UNFCCC, the EPA collects detailed GHG emissions data from the largest emitting facilities in the U.S. through its GHGRP. Data collected by the GHGRP from large stationary sources in the industrial sector show that the utility power sector emits far greater CO_2 emissions than any other industrial sector. Table 5 below presents total GHG emissions in 2013 for the largest emitting industrial sectors as reported to the GHGRP. As shown in Table 4 and Table 5, respectively, CO_2 emissions from fossil fuel-fired EGUs are nearly three times as large as the total reported GHG emissions from the next ten largest emitting industrial sectors in the GHGRP database combined.

TABLE 5—DIRECT GHG EMISSIONS REPORTED TO GHGRP BY LARGEST EMITTING INDUSTRIAL SECTORS (MMT CO_2e)[43]

Industrial sector	2013
Fossil Fuel-Fired EGUs	2,039.8
Petroleum Refineries	176.7
Onshore Oil & Gas Production	94.8
Municipal Solid Waste Landfills	93.0
Iron & Steel Production	84.2
Cement Production	62.8
Natural Gas Processing Plants	59.0
Petrochemical Production	52.7
Hydrogen Production	41.9
Underground Coal Mines	39.8
Food Processing Facilities	30.8

[36] Sinks are physical units or processes that store GHGs, such as forests or underground or deep sea reservoirs of CO_2.

[37] From Table ES–4 of ''Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2013'', Report EPA 430–R–15–004, United States Environmental Protection Agency, April 15, 2015. *http://epa.gov/climatechange/ghgemissions/usinventoryreport.html.*

[38] 1 metric ton (tonne) is equivalent to 1,000 kilograms (kg) and is equivalent to 1.1023 short tons or 2,204.62 pounds (lb).

[39] The energy sector includes all greenhouse gases resulting from stationary and mobile energy activities including fuel combustion and fugitive fuel emissions.

[40] From Table ES–2 ''Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2013'', Report EPA 430–R–15–004, United States Environmental Protection Agency, April 15, 2015. *http://epa.gov/climatechange/ghgemissions/usinventoryreport.html.*

[41] From Table 3–1 ''Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2013'', Report EPA 430–R–15–004, United States Environmental Protection Agency, April 15, 2015. *http://epa.gov/climatechange/ghgemissions/usinventoryreport.html.*

[42] From Table 3–5 ''Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2013'', Report EPA 430–R–15–004, United States Environmental Protection Agency, April 15 2015. *http://epa.gov/climatechange/ghgemissions/usinventoryreport.html.*

[43] U.S. EPA Greenhouse Gas Reporting Program Dataset as of August 18, 2014. *http://ghgdata.epa.gov/ghgp/main.do.*

It should be noted that the discussion above concerned all fossil fuel-fired EGUs. Steam generators emitted 1,627 MMT CO_2e and combustion turbines emitted 401 MMT CO_2e in 2013.[44]

C. The Utility Power Sector

1. Modern Electric System Trends

The EPA includes a background discussion of the electricity system in the Clean Power Plan (CPP) rulemaking, which is the companion rulemaking to this rule that promulgates emission guidelines for states to use in regulating emissions of CO_2 from existing fossil fuel-fired EGUs. Readers are referred to that rulemaking. The following discussion of electricity sector trends is of particular relevance for this rulemaking.

The electricity sector is undergoing a period of intense change. Fossil fuels—such as coal, natural gas, and oil—have historically provided a large percentage of electricity in the U.S., with smaller amounts being provided by other types of generation, including nuclear and renewables such as wind, solar, and hydroelectric power. Coal has historically provided the largest percentage of fossil-fuel generation.[45] In recent years, the nation has seen a sizeable increase in renewable generation such as wind and solar, as well as a shift from coal to natural gas.[46] In 2013, fossil fuels supplied 67 percent of U.S. electricity, but renewables made up 38 percent of the new generation capacity (over 5 GW out of 13.5 GW).[47] From 2007 to 2014, use of lower- and zero-carbon energy sources has grown, while other major energy sources such as coal and oil have experienced declines. Renewable electricity generation, including from large hydro-electric projects, grew from 8 percent to 13 percent over that time period.[48] Between 2000 and 2013, approximately 90 percent of new power generation capacity built in the U.S. has come in the form of natural gas or renewable energy facilities.[49] In 2015, the U.S. Energy Information Administration (EIA) projected the need for 28.4 GW of additional base load or intermediate load generation capacity through 2020, with approximately 0.7 GW of new coal-fired capacity, 5.5 GW of new nuclear capacity, and 14.2 GW of new NGCC capacity already in development.[50]

The change in the resource mix has accelerated in recent years, but wind, solar, other renewables, and energy-efficiency resources have been reliably participating in the electric sector for a number of years. This rapid development of non-fossil fuel resources is occurring as much of the existing power generation fleet in the U.S. is aging and in need of modernization and replacement.[51] For example, the average age of U.S. coal steam units in 2015 is 45 years.[52] In its *2013 Report Card for America's Infrastructure,* the American Society for Civil Engineers noted that ''America relies on an aging electrical grid and pipeline distribution systems, some of which originated in the 1880s.'' [53] While there has been an increased investment in electric transmission infrastructure since 2005, the report also found that ''ongoing permitting issues, weather events, and limited maintenance have contributed to an increasing number of failures and power interruptions.''[54] However, innovative technologies have increasingly entered the electric energy space, helping to provide new answers to how to meet the electricity needs of the nation. These new technologies can enable the nation to answer not just questions as to how to reliably meet electricity demand, but also how to meet electricity demand reliably and cost-effectively[55] with the lowest possible emissions and the greatest efficiency.

Natural gas has a long history of meeting electricity demand in the U.S. with a rapidly growing role as domestic supplies of natural gas have dramatically increased. Natural gas net generation increased by approximately 36 percent between 2004 and 2014.[56] In 2014, natural gas accounted for approximately 27 percent of net generation.[57] The EIA projects that this demand growth will continue, with its *Annual Energy Outlook 2015* (AEO 2015) reference case forecasting that natural gas will produce 31 percent of U.S. electric generation in 2040.[58]

Renewable sources of electric generation also have a history of meeting electricity demand in the U.S. and are expected to have an increasing role going forward. A series of energy crises provided the impetus for renewable energy development in the early 1970s. The OPEC oil embargo in 1973 and oil crisis of 1979 caused oil price spikes, more frequent energy shortages, and significantly affected the national and global economy. In 1978, partly in response to fuel security concerns, Congress passed the Public Utilities Regulatory Policies Act (PURPA) which required local electric utilities to buy power from qualifying facilities (QFs).[59] QFs were either cogeneration facilities [60] or small

[44] These figures are based on data for EGUs in the Acid Rain Program plus additional ones that report to the EPA under the Regional Greenhouse Gas Initiative.

[45] U.S. Energy Information Administration, ''Table 7.2b Electricity Net Generation: Electric Power Sector'' data from April 2014 Monthly Energy Review, release data April 25, 2014, *available at http://www.eia.gov/totalenergy/data/monthly/pdf/sec7_6.pdf.*

[46] U.S. Energy Information Administration, ''Table 7.2b Electricity Net Generation: Electric Power Sector'' data from April 2014 Monthly Energy Review, release data April 25, 2014, *available at http://www.eia.gov/totalenergy/data/monthly/pdf/sec7_6.pdf.*

[47] Based on Table 6.3 (New Utility Scale Generating Units by Operating Company, Plant, Month, and Year) of the U.S. Energy Information Administration (EIA) Electric Power Monthly, data for December 2013, for the following renewable energy sources: Solar, wind, hydro, geothermal, landfill gas, and biomass. Available at: *http://www.eia.gov/electricity/monthly/epm_table_grapher.cfm?t=epmt_6_03.*

[48] Bloomberg New Energy Finance and the Business Council for Sustainable Energy, *2015 Factbook: Sustainable Energy in America,* at 16 (2015), *available at http://www.bcse.org/images/2015%20Sustainable%20Energy%20in%20America%20Factbook.pdf.*

[49] Energy Information Administration, *Electricity: Form EIA–860 detailed data* (Feb. 17, 2015), *available at http://www.eia.gov/electricity/data/eia860/.*

[50] EIA, *Annual Energy Outlook for 2015 with Projections to 2040,* Final Release, *available at http://www.eia.gov/forecasts/AEO/pdf/0383(2015).* The AEO numbers include projects that are under development and model-projected nuclear, coal, and NGCC projects.

[51] Quadrennial Energy Review, *http://energy.gov/epsa/quadrennial-energy-review-qer.*

[52] We calculated the average age of coal steam units based on the NEEDS inventory, and included units with planned retirements in 2015–2016. *See http://www.epa.gov/airmarkets/documents/ipm/needs_v514.xlsx.*

[53] American Society for Civil Engineers, *2013 Report Card for America's Infrastructure* (2013), *available at http://www.infrastructurereportcard.org/energy/.*

[54] American Society for Civil Engineers, *2013 Report Card for America's Infrastructure* (2013), *available at http://www.infrastructurereportcard.org/energy/.*

[55] Business Council for Sustainable Energy Comments in Docket Id. No. EPA–HQ–OAR–2013–0602 at 2 (Nov. 19, 2014).

[56] U.S. Energy Information Administration (EIA), *Electric Power Monthly: Table 1.1 Net Generation by Energy Source: Total (All Sectors), 2004–December 2014* (2015), *available at http://www.eia.gov/electricity/monthly/epm_table_grapher.cfm?t=epmt_1_1.*

[57] *Id.*

[58] The AEO 2015 Reference case projection is a business-as-usual trend estimate, given known technology and technological and demographic trends. EIA explores the impacts of alternative assumptions in other cases with different macroeconomic growth rates, world oil prices, and resource assumptions. U.S. Energy Information Administration (EIA), *Annual Energy Outlook 2015 with Projections to 2040,* at 24–25 (2015), *available at http://www.eia.gov/forecasts/aeo/pdf/0383(2015).pdf.*

[59] Casazza, J. and Delea, F., *Understanding Electric Power Systems,* IEEE Press, at 220–221 (2d ed. 2010).

[60] Cogeneration facilities utilize a single source of fuel to produce both electricity and another form of energy such as heat or steam. Casazza, J. and Delea, F., *Understanding Electric Power Systems,* IEEE Press, at 220–221 (2d ed. 2010).

generation resources that use renewables such as wind, solar, biomass, geothermal, or hydroelectric power as their primary fuels.[61] Through PURPA, Congress supported the development of more renewable energy generation in the U.S. States have taken a significant lead in requiring the development of renewable resources. In particular, a number of states have adopted renewable portfolio standards (RPS). As of 2013, 29 states and the District of Columbia have enforceable RPS or similar laws.[62] In its AEO 2015 Reference case, the EIA found that renewable energy will account for 38 percent of the overall growth in electricity generation from 2013 to 2040.[63] The AEO 2015 Reference case forecasts that the renewables share of U.S. electricity generation will grow from 13 percent in 2013 to 18 percent in 2040.[64]

Price pressures caused by oil embargoes in the 1970s also brought the issues of conservation and energy efficiency to the forefront of U.S. energy policy.[65] This trend continued in the early 1990s. Some state regulatory commissions and utilities supported energy efficiency through least-cost planning, with the National Association of Regulatory Utility Commissioners (NARUC) ''adopting a resolution that called for the utility's least cost plan to be the utility's most profitable plan.'' [66] Energy efficiency has been utilized to meet energy demand to varying levels since that time. As of April 2014, 25 states [67] have ''enacted long-term (3+ years), binding energy savings targets, or energy efficiency resource standards (EERS).'' [68] Funding for energy efficiency programs has grown rapidly in recent years, with budgets for electric efficiency programs totaling $5.9 billion in 2012.[69]

Advancements and innovation in power sector technologies provide the opportunity to address CO_2 emission levels at affected power plants while at the same time improving the overall power system in the U.S. by lowering the carbon intensity of power generation, and ensuring a reliable supply of power at a reasonable cost.

2. Fossil Fuel-Fired EGUs Regulated by this Action, Generally

Natural gas-fired EGUs typically use one of two technologies: NGCC or simple cycle combustion turbines. NGCC units first generate power from a combustion turbine (the combustion cycle). The unused heat from the combustion turbine is then routed to a heat recovery steam generator (HRSG) that generates steam, which is then used to produce power using a steam turbine (the steam cycle). Combining these generation cycles increases the overall efficiency of the system. Simple cycle combustion turbines use a single combustion turbine to produce electricity (*i.e.,* there is no heat recovery or steam cycle). The power output from these simple cycle combustion turbines can be easily ramped up and down making them ideal for ''peaking'' operations.

Coal-fired utility boilers are primarily either pulverized coal (PC) boilers or fluidized bed (FB) boilers. At a PC boiler, the coal is crushed (pulverized) into a powder in order to increase its surface area. The coal powder is then blown into a boiler and burned. In a coal-fired boiler using FB combustion, the coal is burned in a layer of heated particles suspended in flowing air.

Power can also be generated using gasification technology. An IGCC unit gasifies coal or petroleum coke to form a synthetic gas (or syngas) composed of carbon monoxide (CO) and hydrogen (H_2), which can be combusted in a combined cycle system to generate power.

3. Technological Developments and Costs

Natural gas prices have decreased dramatically and generally stabilized in recent years as new drilling techniques have brought additional supply to the marketplace and greatly increased the domestic resource base. As a result, natural gas prices are expected to be competitive for the foreseeable future, and EIA modeling and utility announcements confirm that utilities are likely to rely heavily on natural gas to meet new demand for electricity generation. On average, as discussed below, the cost of generation from a new natural-gas fired power plant (a NGCC unit) is expected to be significantly lower than the cost of generation from a new coal-fired power plant.[70]

Other drivers that may influence decisions to build new power plants are increases in renewable energy supplies, often due to state and federal energy policies. As previously discussed, many states have adopted RPS, which require a certain portion of electricity to come from renewable energy sources such as solar or wind. The federal government has also offered incentives to encourage further deployment of other forms of electric generation including renewable energy sources and new nuclear power plants.

Reflecting these factors, the EIA projections from the last several years show that natural gas is likely to be the most widely-used fossil fuel for new construction of electric generating capacity through 2020, along with renewable energy, nuclear power, and a limited amount of coal with CCS.[71]

While EIA data shows that natural gas is likely to be the most widely-used fossil fuel for new construction of electric generating capacity through 2030, a few coal-fired units still remain as viable projects at various advanced stages of construction and development. One new coal facility that has essentially completed construction,

[61] Casazza, J. and Delea, F., *Understanding Electric Power Systems,* IEEE Press, at 220–221 (2d ed. 2010).

[62] U.S. Energy Information Administration (EIA), *Annual Energy Outlook 2014 with Projections to 2040,* at LR–5 (2014).

[63] U.S. Energy Information Administration (EIA), *Annual Energy Outlook 2015 with Projections to 2040,* at E–12 (2015).

[64] U.S. Energy Information Administration (EIA), *Annual Energy Outlook 2015 with Projections to 2040,* at 24–25(2015).

[65] Edison Electric Institute, *Making a Business of Energy Efficiency: Sustainable Business Models for Utilities,* at 1 (2007). Congress passed legislation in the 1970s that jumpstarted energy efficiency in the U.S. For example, President Ford signed the Energy Policy and Conservation Act (EPCA) of 1975—the first law on the issue. EPCA authorized the Federal Energy Administration (FEA) to ''develop energy conservation contingency plans, established vehicle fuel economy standards, and authorized the creation of efficiency standards for major household appliances.'' Alliance to Save Energy, *History of Energy Efficiency,* at 6 (2013) (citing Anders, *''The Federal Energy Administration,''* 5; Energy Policy and Conservation Act, S. 622, 94th Cong. (1975–1976)), *available at https://www.ase.org/sites/ase.org/files/resources/Media%20browser/ee_commission_history_report_2–1–13.pdf.*

[66] Edison Electric Institute, *Making a Business of Energy Efficiency: Sustainable Business Models for Utilities,* at 1 (2007), *available at http://www.eei.org/whatwedo/PublicPolicyAdvocacy/State Regulation/Documents/Making_Business_Energy_Efficiency.pdf.*

[67] American Council for an Energy-Efficient Economy, *State Energy Efficiency Resource Standards (EERS)* (2014), *available at http://aceee.org/files/pdf/policy-brief/eers-04-2014.pdf.* ACEEE did not include Indiana (EERS eliminated), Delaware (EERS pending), Florida (programs funded at levels far below what is necessary to meet targets), Utah, or Virginia (voluntary standards) in its calculation.

[68] American Council for an Energy-Efficient Economy, *State Energy Efficiency Resource Standards (EERS)* (2014), *available at http://aceee.org/files/pdf/policy-brief/eers-04–2014.pdf.*

[69] American Council for an Energy-Efficient Economy, *The 2013 State Energy Efficiency Scorecard,* at 17 (Nov. 2013), *available at http://aceee.org/sites/default/files/publications/researchreports/e13k.pdf.*

[70] Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2015 *http://www.eia.gov/forecasts/aeo/electricity_generation.html.*

[71] *http://www.eia.gov/forecasts/aeo/pdf/0383(2013).pdf; http://www.eia.gov/forecasts/aeo/pdf/0383(2012).pdf; http://prod-http-80-800498448.us-east-1.elb.amazonaws.com/w/images/6/6d/0383%282011%29.pdf.*

Southern Company's Kemper County Energy Facility, deploys IGCC with partial CCS. Additionally, another project, Summit Power's Texas Clean Energy Project (TCEP), which will deploy IGCC with CCS, continues as a viable project.[72] The EIA modeling projects that coal-fired power generation will remain the single largest portion of the electricity sector beyond 2030. The EIA modeling also projects that few, if any, new coal-fired EGUs will be built in this decade and that those that are built will have CCS.[73] Continued progress on these projects is consistent with the EIA modeling that suggests that a small number of coal-fired power plants may be constructed. The primary reasons for this rate of current and projected future development of new coal projects include highly competitive natural gas prices, lower electricity demand growth, and increases in the supply of renewable energy. We recognize, however, that a variety of factors may come into play in a decision to build new power generation, and we want to ensure that there are standards in place to make sure that whatever fuel is utilized is done so in a way that minimizes CO_2 emissions, as Congress intended with CAA section 111.[74]

4. Energy Sector Modeling

Various energy sector modeling efforts, including projections from the EIA and the EPA, forecast trends in new power plant construction and utilization of existing power plants that are consistent with the above-described technological developments and costs. The EIA's annual report, the AEO, forecasts the structure of and developments in the power sector. These reports are based on economic modeling that reflects existing policy and regulations, such as state RPS programs and federal tax credits for renewables.[75] The current report, AEO 2015:[76] (i) Shows that a modest amount of coal-fired power plants that are currently under construction are expected to begin operation in the next several years (referred to as ''planned''); and (ii) projects in the reference case[77] that a very small amount of new (''unplanned'') conventional coal-fired capacity, with CCS, will come online after 2012 and through 2037 in response to federal and state incentives. According to the AEO 2015, the vast majority of new generating capacity during this period will be either natural gas-fired or renewable sources. Similarly, the EIA projections from the last several years show that natural gas is likely to be the most widely-used fossil fuel for new construction of electric generating capacity through 2030.[78]

Specifically, the AEO 2015 projects 30.3 GW of additional base load or intermediate load generation capacity through 2020 (this includes projects that are under development—*i.e.,* being constructed or in advance planning—and model-projected nuclear, coal, and NGCC projects). The vast majority of this new electric capacity (20.4 GW) is already under development (under construction or in advanced planning); it includes about 0.7 GW of new coal-fired capacity, 5.5 GW of new nuclear capacity, and 14.2 GW of new NGCC capacity. The EPA believes that most current fossil fuel-fired projects are already designed to meet limits consistent with this rule (or they have already commenced construction and are thus not subject to these final standards). The AEO 2015 also projects an additional 9.9 GW of new base load capacity additions, which are model-projected (unplanned). This consists of 7.7 GW of new NGCC capacity, 1.2 GW of new geothermal capacity, 0.7 GW of new hydroelectric capacity, and 0.3 GW of new coal equipped with CCS (incentivized with some government funding). Therefore, the AEO 2015 projection suggests that the new power generation capacity added through 2020 is expected to already meet the final emissions standards without incurring further control costs. This is also true during the period from 2020 through 2030, where new model-projected (unplanned) intermediate and base load capacity is expected to be compliant with the standards without incurring further control costs (*i.e.,* an additional 31.3 GW of NGCC and no additional coal, for a total, from 2015 through 2030, of 39 GW of NGCC and 0.3 GW of coal with CCS).

Under the EIA projections, existing coal-fired generation will remain an important part of the mix for power generation. Modeling from both the EIA and the EPA project that coal-fired generation will remain the largest single source of electricity in the U.S. through 2040. Specifically, in the EIA's AEO 2015, coal will supply approximately 40 percent of all electricity in the electric power sector in both 2020 and 2025.

The EPA modeling using the Integrated Planning Model (IPM), a detailed power sector model that the EPA uses to support power sector regulations, also shows limited future construction of new coal-fired power plants under the base case.[79] The EPA's projections from IPM can be found in the RIA.

5. Integrated Resource Plans

The trends in the power sector described above are also apparent in publicly available long-term resource plans, known as integrated resource plans (IRPs).

The EPA has reviewed publicly available IRPs from a range of companies (*e.g.,* varying in size, location, current fuel mix), and these plans are generally consistent with both EIA and EPA modeling projections.[80] These IRPs indicate that companies are focused on demand-side management programs to lower future electricity demand and are mostly reliant on a mix of new natural gas-fired generation and renewable energy to meet increased load demand and to replace retired generation capacity.

Notwithstanding this clear trend towards natural gas-fired generation and renewables, many of the IRPs highlight the value of fuel diversity and include options to diversify new generation capacity beyond natural gas and renewable energy. Several IRPs indicate that companies are considering new nuclear generation, including either traditional nuclear power plants or small modular reactors, and a smaller number are considering new coal-fired generation capacity with and without CCS technology. Based on public comments and on the information contained in these IRPs, the EPA acknowledges that a small number of

[72] ''Odessa coal-to-gas power plant to break ground this year'', Houston Chronicle (April 1, 2015).

[73] This projection is for business as usual and does not account for the proposed or final CO_2 emission standard. Even in its sensitivity analysis that assumes higher natural gas prices and electricity demand, EIA does not project any additional coal-fired power plants beyond its reference case until 2023, in a case where power companies assume no GHGs emission limitations, and until 2024 in a case where power companies do assume GHGs emission limitations.

[74] These sources received federal assistance under EPAct 2005. See Section III.H.3.g below. However, none of the constraints in that Act affect the discussion in the text above, since that discussion does not relate to technology use or emissions reduction by these sources.

[75] *http://www.eia.gov/forecasts/aeo/chapter_legs_regs.cfm.*

[76] Energy Information Administration's Annual Energy Outlook for 2015, Final Release available at *http://www.eia.gov/forecasts/aeo/index.cfm.*

[77] EIA's reference case projections are the result of its baseline assumptions for economic growth, fuel supply, technology, and other key inputs.

[78] Annual Energy Outlook 2010, 2011, 2012, 2013, 2014 and 2015.

[79] *http://www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev410.html#documentation.*

[80] Technical Support Document—''Review of Electric Utility Integrated Resource Plans'' (May 2015), available in the rulemaking docket EPA–HQ–OAR–2013–0495.

new coal-fired power plants may be built in the near future. While this outcome would be contrary to the economic modeling predictions, the agency understands that economic modeling may not fully reflect the range of factors that a particular company may consider when evaluating new generation options, such as fuel diversification. Further, it is possible that some of this potential new coal-fired construction may occur because developers are able to design projects with specific business plans, such as the cogeneration of chemicals, which allow the source to provide competitively priced electricity in specific geographic regions.

D. Statutory Background

The U.S. Supreme Court ruled in *Massachusetts* v. *EPA* that GHGs [81] meet the definition of ''air pollutant'' in the CAA,[82] and premised its decision in *AEP* v. *Connecticut,*[83] that the CAA displaced any federal common law right to compel reductions in CO_2 emissions from fossil fuel-fired power plants, on its view that CAA section 111 applies to GHG emissions.

CAA section 111 authorizes and directs the EPA to prescribe new source performance standards (NSPS) applicable to certain new stationary sources (including newly constructed, modified and reconstructed sources).[84] As a preliminary step to regulation, the EPA must list categories of stationary sources that the Administrator, in his or her judgment, finds ''cause[], or contribute[] significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare.'' The EPA has listed and regulated more than 60 stationary source categories under CAA section 111.[85] The EPA listed the two source categories at issue here in the 1970s—listing fossil fuel-fired electric steam generating units in 1971 [86] and listing combustion turbines in 1977.[87]

Once the EPA has listed a source category, the EPA proposes and then promulgates ''standards of performance'' for ''new sources'' in the category.[88] A ''new source'' is ''any stationary source, the construction or modification of which is commenced after,'' in general, final standards applicable to that source are promulgated or, if earlier, proposed.[89] A modification is ''any physical change . . . or change in the method of operation . . . which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted.'' [90] The EPA, through regulations, has determined that certain types of changes are exempt from consideration as a modification.[91]

The NSPS general provisions (40 CFR part 60, subpart A) provide that an existing source is considered to be a new source if it undertakes a ''reconstruction,'' which is the replacement of components of an existing facility to an extent that (1) the fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility, and (2) it is technologically and economically feasible to meet the applicable standards.[92]

CAA section 111(a)(1) defines a ''standard of performance'' as ''a standard for emissions . . . achievable through the application of the best system of emission reduction which [considering cost, non-air quality health and environmental impact, and energy requirements] the Administrator determines has been adequately demonstrated.'' This definition makes clear that the standard of performance must be based on ''the best system of emission reduction . . . adequately demonstrated'' (BSER).

The standard that the EPA develops, reflecting the performance of the BSER, is commonly a numeric emission limit, expressed as a numeric performance level that can either be normalized to a rate of output or input (*e.g.,* tons of pollution per amount of product produced—a so-called rate-based standard), or expressed as a numeric limit on mass of pollutant that may be emitted (*e.g.,* 100 ug/m^3—parts per billion). Generally, the EPA does not prescribe a particular technological system that must be used to comply with a standard of performance.[93] Rather, sources generally may select any measure or combination of measures that will achieve the emissions level of the standard.[94] In establishing standards of performance, the EPA has significant discretion to create subcategories based on source type, class, or size.[95]

The text and legislative history of CAA section 111, as well as relevant court decisions, identify the factors that the EPA is to consider in making a BSER determination. The system of emission reduction must be technically feasible, the costs of the system must be reasonable, and the emission standard that the EPA promulgates based on the system of emission reduction must be achievable. In addition, in identifying a BSER, the EPA must consider the amount of emissions reductions attributable to the system, and must also consider non-air quality health and environmental impacts and energy requirements. The case law addressing CAA section 111 makes it clear that the EPA has discretion in weighing costs, amount of emission reductions, energy requirements, and impacts of non-air quality pollutants, and may weigh them differently for different types of sources or air pollutants. We note that under the case law of the D.C. Circuit, another factor is relevant for the BSER determination: Whether the standard would effectively promote further deployment or development of advanced technologies. Within the constraints just described, the EPA has discretion in identifying the BSER and the resulting emission standard. See generally Section III.H below.

For more than four decades, the EPA has used its authority under CAA section 111 to set cost-effective emission standards which ensure that newly constructed, reconstructed, and modified stationary sources use the best performing technologies to limit emissions of harmful air pollutants. In this final action, the EPA is following the same well-established interpretation and application of the law under CAA section 111 to address GHG emissions from newly constructed, reconstructed, and modified fossil fuel-fired power plants. For each of the standards in this final action, the EPA considered a number of alternatives and evaluated them against the statutory factors. The BSER for each category of affected EGUs and the standards of performance based on these BSER are based on that evaluation.

[81] The EPA's 2009 endangerment finding defines the air pollution which may endanger public health and welfare as the well-mixed aggregate group of the following gases: CO_2, methane (CH_4), nitrous oxide (N_2O), sulfur hexafluoride (SF_6), hydrofluorocarbons (HFCs), and perfluorocarbons (PFCs).

[82] 549 U.S. 497, 520 (2007).

[83] 131 S.Ct. 2527, 2537–38 (2011).

[84] CAA section 111(b)(1)(A).

[85] *See generally* 40 CFR part 60, subparts D–MMMM.

[86] 36 FR 5931 (March 31, 1971).

[87] 42 FR 53657 (October 3, 1977).

[88] CAA section 111(b)(1)(B).

[89] CAA section 111(a)(2).

[90] CAA section 111(a)(4); See also 40 CFR 60.14 concerning what constitutes a modification, how to determine the emission rate, how to determine an emission increase, and specific actions that are not, by themselves, considered modifications.

[91] 40 CFR 60.2, 60.14(e).

[92] 40 CFR 60.15.

[93] CAA section 111(b)(5) and (h).

[94] CAA section 111(b)(5).

[95] CAA section 111(b)(2); see also *Lignite Energy Council* v. *EPA,* 198 F. 3d 930, 933 (D.C. Cir. 1999).

E. Regulatory Background

In 1971, the EPA initially included fossil fuel-fired EGUs (which includes natural gas, petroleum and coal) that use steam-generating boilers in a category that it listed under CAA section 111(b)(1)(A),[96] and promulgated the first set of standards of performance for sources in that category, which it codified in subpart D.[97] In 1977, the EPA initially included fossil fuel-fired combustion turbines in a category that the EPA listed under CAA section 111(b)(1)(A),[98] and the EPA promulgated standards of performance for that source category in 1979, which the EPA codified in subpart GG.[99]

The EPA has revised those regulations, and in some instances, has revised the codifications (that is, the 40 CFR part 60 subparts), several times over the ensuing decades. In 1979, the EPA divided subpart D into 3 subparts—Da (''Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978''), Db (''Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units'') and Dc (''Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units'')—in order to codify separate requirements that it established for these subcategories.[100] In 2006, the EPA created subpart KKKK, ''Standards of Performance for Stationary Combustion Turbines,'' which applied to certain sources previously regulated in subparts Da and GG.[101] None of these subsequent rulemakings, including the revised codifications, however, constituted a new listing under CAA section 111(b)(1)(A).

The EPA promulgated amendments to subpart Da in 2006, which included new standards of performance for criteria pollutants for EGUs, but did not include specific standards of performance for CO_2 emissions.[102]

Petitioners sought judicial review of the rule, contending, among other issues, that the rule was required to include standards of performance for GHG emissions from EGUs.[103] The January 8, 2014 preamble to the proposed CO_2 standards for new EGUs [104] includes a discussion of the GHG-related litigation of the 2006 Final Rule as well as other GHG-associated litigation.

F. Development of Carbon Pollution Standards for Fossil Fuel-Fired Electric Utility Generating Units

On April 13, 2012, the EPA initially proposed standards under CAA section 111 for newly constructed fossil fuel-fired electric utility steam generating units. 77 FR 22392 (''April 2012 proposal''). The EPA withdrew that proposal (79 FR 1352 (January 8, 2014)), and, on the same day, proposed the standards addressed in this final rule. 79 FR 1430 (''January 2014 proposal''). Specifically, the EPA proposed standards under CAA section 111 to limit emissions of CO_2 from newly constructed fossil fuel-fired electric utility steam generating units and newly constructed natural gas-fired stationary combustion turbines.

In support of the January 2014 proposal, on February 26, 2014, the EPA published a notice of data availability (NODA) (79 FR 10750). Through the NODA and an associated technical support document, *Effect of EPAct05 on Best System of Emission Reduction for New Power Plants,* the EPA solicited comment on its interpretation of the provisions in the Energy Policy Act of 2005 (EPAct05),[105] including how the provisions may affect the rationale for the EPA's proposed determination that partial CCS is the best system of emission reduction adequately demonstrated for fossil fuel-fired electric utility steam generating units.

On June 18, 2014, the EPA proposed standards of performance to limit emissions of CO_2 from modified and reconstructed fossil fuel-fired electric utility steam generating units and natural gas-fired stationary combustion turbines (79 FR 34960; June 2014 proposal). Specifically, the EPA proposed standards of performance for: (1) Modified fossil fuel-fired electric utility steam generating units, (2) modified natural gas-fired stationary combustion turbines, (3) reconstructed fossil fuel-fired electric utility steam generating units, and (4) reconstructed natural gas-fired stationary combustion turbines.

G. Stakeholder Engagement and Public Comments on the Proposals

1. Stakeholder Engagement

The EPA has engaged extensively with a broad range of stakeholders and the general public regarding climate change, carbon pollution from power plants, and carbon pollution reduction opportunities. These stakeholders included industry and electric utility representatives, state and local officials, tribal officials, labor unions, non-governmental organizations and many others.

In February and March 2011, early in the process of developing carbon pollution standards for new power plants, the EPA held five listening sessions to obtain information and input from key stakeholders and the public. Each of the five sessions had a particular target audience: The electric power industry, environmental and environmental justice organizations, states and tribes, coalition groups, and the petroleum refinery industry.

The EPA conducted subsequent outreach prior to the June 2014 proposals of standards for modified and reconstructed EGUs and emission guidelines for existing EGUs, as well as during the public comment periods for the proposals. Although this stakeholder outreach was primarily framed around the GHG emission guidelines for existing EGUs, the outreach encompassed issues relevant to this rulemaking and provided an opportunity for the EPA to better understand previous state and stakeholder experience with reducing CO_2 emissions in the power sector. In addition to 11 public listening sessions, the EPA held hundreds of meetings with individual stakeholder groups, and meetings that brought together a variety of stakeholders to discuss a wide range of issues related to the electricity sector and regulation of GHGs under the CAA. The agency met with electric utility associations and electricity grid operators. Agency officials engaged with labor unions and with leaders representing large and small industries. The agency also met with energy industries, such as coal and natural gas interests, as well as with representatives of energy-intensive industries, such as

[96] 36 FR 5931 (March 31, 1971).

[97] ''Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction Is Commenced After August 17, 1971,'' 36 FR 24875 (December 23, 1971) codified at 40 CFR 60.40–46.

[98] 42 FR 53657 (October 3, 1977).

[99] ''Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978,'' 44 FR 33580 (June 11, 1979).

[100] 44 FR 33580 (June 11, 1979).

[101] 71 FR 38497 (July 6, 2006), as amended at 74 FR 11861 (March 20, 2009).

[102] ''Standards of Performance for Electric Utility Steam Generating Units, Industrial-Commercial-Institutional Steam Generating Units, and Small Industrial-Commercial-Institutional Steam Generating Units, Final Rule.'' 71 FR 9866 (February 27, 2006).

[103] *State of New York, et al.* v. *EPA,* No. 06–1322.

[104] 79 FR 1430, 1444.

[105] See Section III.H.3.g below. The Energy Policy Act of 2005 (EPAct05) was signed into law by President George W. Bush on August 8, 2005. EPAct05 was intended to address energy production in the United States, including: (1) Energy efficiency; (2) renewable energy; (3) oil and gas; (4) coal; (5) Tribal energy; (6) nuclear matters and security; (7) vehicles and motor fuels, including ethanol; (8) hydrogen; (9) electricity; (10) energy tax incentives; (11) hydropower and geothermal energy; and (12) climate change technology. *www2.epa.gov/laws-regulations/summary-energy-policy-act.*

the iron and steel, and aluminum industries, to better understand the potential concerns of large industrial purchasers of electricity. In addition, the agency met with companies that offer new technology to prevent or reduce carbon pollution. The agency provided and encouraged multiple opportunities for engagement with state, local, tribal, and regional environmental and energy agencies. The EPA also met with representatives of environmental justice organizations, environmental groups, public health professionals, public health organizations, religious organizations, and other community stakeholders.

The EPA received more than 2.5 million comments submitted in response to the original April 2012 proposal for newly constructed fossil fuel-fired EGUs. Because the original proposal was withdrawn, the EPA instructed commenters that wanted their comments on the April 2012 proposal to be considered in connection with the January 2014 proposal to submit new comments to the EPA or to re-submit their previous comments. We received more comments in response to the January 2014 proposal, as discussed in the section below.

The EPA has given stakeholder input provided prior to the proposals, as well as during the public comment periods for each proposal, careful consideration during the development of this rulemaking and, as a result, it includes elements that are responsive to many stakeholder concerns and that enhance the rule. This preamble and the Response-to-Comments (RTC) document summarize and provide the agency's responses to the comments received.

2. Comments on the January 2014 Proposal For Newly Constructed Fossil Fuel-Fired EGUs

Upon publication of the January 8, 2014 proposal for newly constructed fossil fuel-fired EGUs, the EPA provided a 60-day public comment period. On March 6, 2014, in order to provide the public additional time to submit comments and supporting information, the EPA extended the comment period by 60 days, to May 9, 2014, giving stakeholders over 120 days to review, and comment upon, the January 2014 proposal, as well as the NODA. A public hearing was held on February 6, 2014, with 159 speakers presenting testimony.

The EPA received more than 2 million comments on the proposed standards for newly constructed fossil fuel-fired EGUs from a range of stakeholders that included industry and electric utility representatives, trade groups, equipment manufacturers, state and local government officials, academia, environmental organizations, and various interest groups. The agency received comments on a range of topics, including the determination that a new highly-efficient steam generating EGU implementing partial CCS was the BSER for such sources, the level of the CO_2 standard based on implementation of partial CCS, the criteria that define which newly constructed natural gas-fired stationary combustion turbines will be subject to standards, the establishment of subcategories based on combustion turbine size, and the rule's potential effects on the Prevention of Significant Deterioration (PSD) preconstruction permit program and Title V operating permit program.

3. Comments on the June 2014 Proposal For Modified and Reconstructed Fossil Fuel-Fired EGUs

Upon publication of the June 18, 2014 proposal for modified and reconstructed fossil fuel-fired EGUs, the EPA offered a 120-day public comment period—through October 16, 2014. The EPA held public hearings in four locations during the week of July 28, 2014. These hearings also addressed the EPA's June 18, 2014 proposed emission guidelines for existing fossil fuel-fired EGUs (reflecting the connections between the proposed standards for modified and reconstructed sources and the proposed emission guidelines). A total of 1,322 speakers testified, and a further 1,450 attended but did not speak. The speakers were provided the opportunity to present data, views, or arguments concerning one or both proposed actions.

The EPA received over 200 comments on the proposed standards for modified and reconstructed fossil fuel-fired EGUs from a range of stakeholders similar to those that submitted comments on the January 2014 proposal for newly constructed fossil fuel-fired EGUs (*i.e.,* industry and electric utility representatives, trade groups, equipment manufacturers, state and local government officials, academia, environmental organizations, and various interest groups). The agency received comments on a range of topics, including the methodology for determining unit-specific CO_2 standards for modified steam generating units and the use of supercritical boiler conditions as the basis for the CO_2 standards for certain reconstructed steam generating units. Many of the comments regarding modified and reconstructed natural gas-fired stationary combustion turbines are similar to the comments regarding newly constructed combustion turbines described above (*e.g.,* applicability criteria and subcategories based on turbine size).

III. Regulatory Authority, Affected EGUs and Their Standards, and Legal Requirements

In this section, we describe our authority to regulate CO_2 from fossil fuel-fired EGUs. We also describe our decision to combine the two existing categories of affected EGUs—steam generators and combustion turbines—into a single category of fossil fuel-fired EGUs for purposes of promulgating standards of performance for CO_2 emissions. We also explain that we are codifying all of the requirements in this rule for new, modified, and reconstructed affected EGUs in new subpart TTTT of part 60 of Title 40 of the Code of Federal Regulations. In addition, we explain which sources are and are not affected by this rule, and the format of these standards. Finally, we describe the legal requirements for establishing these emission standards.

A. Authority To Regulate Carbon Dioxide From Fossil Fuel-Fired EGUs

The EPA's authority for this rule is CAA section 111(b)(1). CAA section 111(b)(1)(A) requires the Administrator to establish a list of source categories to be regulated under section 111. A category of sources is to be included on the list "if in [the Administrator's] judgment it causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health and welfare." This determination is commonly referred to as an "endangerment finding" and that phrase encompasses both the "causes or contributes significantly" component and the "endanger public health and welfare" component of the determination. Then, for the source categories listed under section 111(b)(1)(A), the Administrator promulgates, under section 111(b)(1)(B), "standards of performance for new sources within such category."

In this rule, the EPA is establishing standards under section 111(b)(1)(B) for source categories that it has previously listed and regulated for other pollutants and which now are being regulated for an additional pollutant. Because of this, there are two aspects of section 111(b)(1) that warrant particular discussion.

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 affected EGUs in order to establish standards of performance for the CO_2 emissions 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), and 231(a)(2)(A); *see also American Electric Power Co. Inc.,* v. *Connecticut,* 131 S. Ct. 2527, 2539 (2011) (''[T]he Clean Air Act directs the 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 standards, it is appropriate for the 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).[106]

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 (June 24, 2008) (concluding that 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 D.C. 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 oxides of nitrogen (NO_X), sulfur dioxide (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.

In this rulemaking, the EPA has a rational basis for concluding that emissions of CO_2 from fossil fuel-fired power plants, which are the major U.S. source of GHG air pollution, merit regulation under CAA section 111. As noted, in 2009, the EPA made a finding that GHG air pollution may reasonably be anticipated to endanger public health or welfare, and in 2010, the EPA denied petitions to reconsider that finding. The EPA extensively reviewed the available science concerning GHG pollution and its impacts in taking those actions. In 2012, the U.S. Court of Appeals for the D.C. Circuit upheld the finding and the denial of petitions to reconsider.[107] In addition, assessments from the NRC, the IPCC, and other organizations published after 2010 lend further credence to the validity of the Endangerment Finding. No information that commenters have presented or that the EPA has reviewed provides a basis for reaching a different conclusion. Indeed, current and evolving science discussed in detail in Section II.A of this preamble is confirming and enhancing our understanding of the near- and longer-term impacts emissions of CO_2 are having on Earth's climate and the adverse public health, welfare, and economic consequences that are occurring and are projected to occur as a result.

Moreover, the high level of GHG emissions from fossil fuel-fired EGUs makes clear that it is rational for the EPA to regulate GHG emissions from this sector. EGUs emit almost one-third of all U.S. GHGs and comprise by far the largest stationary source category of GHG emissions; indeed, as noted above, the CO_2 emissions from fossil fuel-fired EGUs are almost three times as much as the emissions from the next ten source categories combined. Further, the CO_2 emissions from even a single new coal-fired power plant may amount to millions of tons each year. See, *e.g.,* Section V.K below (noting that even the difference in CO_2 emissions between a highly efficient SCPC and the same unit meeting today's standard of performance can amount to hundreds of thousands of tons each year). These facts provide a rational basis for regulating CO_2 emissions from affected EGUs.

Some commenters have argued that the EPA is required to make a new endangerment finding before it may regulate CO_2 from EGUs. We disagree, for the reasons discussed above. Moreover, as discussed in the January 2014 proposal,[108] even if CAA section 111 required the EPA to make endangerment and cause-or-contribute significantly findings as prerequisites for this rulemaking, then, so far as the ''CO_2 endangers public health and welfare'' component of an endangerment finding is concerned, the information and conclusions described above should be considered to constitute the requisite endangerment finding. Similarly, so far as a cause-or-contribute significantly finding is concerned, the information and conclusions described above should be considered to constitute the requisite finding. The EPA's rational basis for regulating CO_2 under CAA section 111 is based primarily on the analysis and conclusions in the EPA's 2009 Endangerment Finding and 2010 denial of petitions to reconsider that Finding, coupled with the subsequent assessments from the IPCC and NRC that describe scientific developments since those EPA actions. In addition, we have reviewed comments presenting other scientific information to

[106] In *Chevron,* the U.S. Supreme Court held that an agency must, at Step 1, determine whether Congress's intent as to the specific matter at issue is clear, and, if so, the agency must give effect to that intent. If Congressional intent is not clear, then, at Step 2, the agency has discretion to fashion an interpretation that is a reasonable construction of the statute.

[107] *Coalition for Responsible Regulation* v. *EPA,* 684 F.3d 102, 119–126 (D.C. Circuit 2012).

[108] 79 FR 1430, 1455–56 (January 8, 2014).

determine whether that information has any meaningful impact on our analysis and conclusions. For both the endangerment finding and the rational basis, the EPA focused on public health and welfare impacts within the United States, as it did in the 2009 Finding. The impacts in other world regions strengthen the case because impacts in other world regions can in turn adversely affect the United States or its citizens.

More specifically, our approach here—reflected in the information and conclusions described above—is substantially similar to that reflected in the 2009 Endangerment Finding and the 2010 denial of petitions to reconsider. The D.C. Circuit upheld that approach in *Coalition for Responsible Regulation* v. *EPA,* 684 F.3d 102, 117–123 (D.C. Cir. 2012) (noting, among other things, the ''substantial . . . body of scientific evidence marshaled by EPA in support of the Endangerment Finding'' (id. at 120); the ''substantial record evidence that anthropogenic emissions of greenhouse gases 'very likely' caused warming of the climate over the last several decades'' (id. at 121); ''substantial scientific evidence . . . that anthropogenically induced climate change threatens both public health and public welfare . . . [through] extreme weather events, changes in air quality, increases in food- and water-borne pathogens, and increases in temperatures'' (id.); and ''substantial evidence . . . that the warming resulting from the greenhouse gas emissions could be expected to create risks to water resources and in general to coastal areas. . . .'' (id.)). The facts, unfortunately, have only grown stronger and the potential adverse consequences to public health and the environment more dire in the interim. Accordingly, that approach would support an endangerment finding for this rulemaking.[109]

Likewise, if the EPA were required to make a cause-or-contribute-significantly finding for CO_2 emissions from the fossil fuel-fired EGUs as a prerequisite to regulating such emissions under CAA section 111, the same facts that support our rational basis determination would support such a finding. As shown in Tables 3 and 4 in this preamble, fossil fuel-fired EGUs are very large emitters of CO_2. All told, these fossil fuel-fired EGUs emit almost one-third of all U.S. GHG emissions, and are responsible for almost three times as much as the emissions from the next ten stationary source categories combined. The CO_2 emissions from even a single new coal-fired power plant may amount to millions of tons each year, and the CO_2 emissions from even a single NGCC unit may amount to one million or more tons per year. It is not necessary in this rulemaking for the EPA to decide whether it must identify a specific threshold for the amount of emissions from a source category that constitutes a significant contribution; under any reasonable threshold or definition, the emissions from combustion turbines and steam generators are a significant contribution. Indeed, these emissions far exceed in magnitude the emissions from motor vehicles, which have already been held to contribute to the endangerment. See *Coalition for Responsible Regulation,* 684 F. 3d at 121 (''substantial evidence'' supports the EPA's determination ''that motor-vehicle emissions of greenhouse gases contribute to climate change and thus to the endangerment of public health and welfare'').[110]

B. Treatment of Categories and Codification in the Code of Federal Regulations

As discussed in the January 2014 proposal of carbon pollution standards for newly constructed EGUs (79 FR 1430) and above, in 1971 the EPA listed fossil fuel-fired steam generating boilers as a new category subject to CAA section 111 rulemaking, and in 1979 the EPA listed fossil fuel-fired combustion turbines as a new category subject to the CAA section 111 rulemaking. In the ensuing years, the EPA has promulgated standards of performance for the two categories and codified those standards, at various times, in 40 CFR part 60, subparts D, Da, GG, and KKKK.

In the January 2014 proposal of carbon pollution standards for newly constructed EGUs (79 FR 1430) and the June 2014 proposal of carbon pollution standards for modified and reconstructed EGUs (79 FR 34960), the EPA proposed separate standards of performance for new, modified, and reconstructed sources in the two categories. The EPA took comment on combining the two categories into a single category solely for purposes of the CO_2 emissions from new, modified, and reconstructed affected EGUs. In addition, the EPA proposed codifying the standards of performance in the same Da and KKKK subparts that currently contain the standards of performance for other pollutants from those sources addressed in the NSPS program, but co-proposed codifying all the standards of performance for CO_2 emissions in a new 40 CFR part 60, subpart TTTT.

In this rule, the EPA is combining the steam generator and combustion turbine categories into a single category of fossil fuel-fired electricity generating units for purposes of promulgating standards of performance for GHG emissions. Combining the two categories is reasonable because they both provide the same product: Electricity services. Moreover, combining them in this rule is consistent with our decision to combine them in the CAA section 111(d) rule for existing sources that accompanies this rule. In addition,

[109] Nor does the EPA consider the cost of potential standards of performance in making this Finding. Like the Endangerment Finding under section 202(a) at issue in *State of Massachusetts* v. *EPA,* 549 U.S. 497 (2007) the pertinent issue is a scientific inquiry as to whether an endangerment to public health or welfare from the relevant air pollution may reasonably be anticipated. Where, as here, the scientific inquiry conducted by the EPA indicates that these statutory criteria are met, the Administrator does not have discretion to decline to make a positive endangerment finding to serve other policy grounds. Id. at 532–35. In this regard, an endangerment finding is analogous to setting national ambient air quality standards under section 109(b), which similarly call on the Administrator to set standards that in her ''judgment'' are ''requisite to protect the public health''. The EPA is not permitted to consider potential costs of implementation in setting these standards. *Whitman* v. *American Trucking Assn's,* 531 U.S. 457, 466 (2001); see also *Michigan* v. *EPA,* U.S. (no. 14–46, June 29, 2015) slip op. pp. 10–11 (reiterating *Whitman* holding). The EPA notes further that section 111(b)(1) contains no terms such as ''necessary and appropriate'' which could suggest (or, in some contexts, require) that costs may be considered as part of the finding. Compare CAA section 111(n)(1)(A); see *State of Michigan,* slip op. pp. 7–8. The EPA, of course, must consider costs in determining whether a best system of emission reduction is adequately demonstrated and so can form the basis for a section 111(b) standard of performance, and the EPA has carefully considered costs here and found them to be reasonable. See section V. H. and I. below. The EPA also has found that the rule's quantifiable benefits exceed regulatory costs under a range of assumptions were new capacity to be built. RIA chapter 5 and section XIII.G below. Accordingly, this endangerment finding would be justified if (against our view) it is both required, and (again, against our view) costs are to be considered as part of the finding.

[110] The ''air pollution'' defined in the Endangerment Finding is the atmospheric mix of six long-lived and directly emitted greenhouse gases: Carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6). See 74 FR 66496 at 66497. The standards of performance adopted in the present rulemaking address only one component of this air pollution: CO_2. This is reasonable, given that CO_2 is the air pollutant emitted in the largest volume by the source category, and which is (necessarily) emitted by every affected EGU. There is, of course, no requirement that standards of performance address each component of the air pollution which endangers. Section 111(b)(1)(A) requires the EPA to establish ''standards of performance'' for listed source categories, and the definition of ''standard of performance'' in section 111(a)(1) does not specify which air pollutants must be controlled. See also Section III.G below explaining that CH_4 and N_2O emissions represent less than 1 percent of total estimated GHG emissions (as CO_2e) from fossil fuel-fired electric power generating units.

many of the monitoring, reporting, and verification requirements are the same for both source categories, and, as discussed next, we are codifying all requirements in a single new subpart of the regulations; as a result, combining the two categories into a single category will reduce confusion. It should be noted that in this rule, we are not combining the two categories for purposes of standards of performance for other air pollutants.

Because these two source categories are pre-existing listed source categories and the EPA will not be subjecting any additional sources in the categories to CAA regulation for the first time, the combination of these two categories is not considered a new source category subject to the listing requirements of CAA section 111(b)(1)(A). As a result, this final rule does not list a new category under CAA section 111(a)(1)(A), nor does this final rule revise either of the two source categories. Thus, the EPA is not required to make a new endangerment and contribution finding for the combination of the two categories,[111] although as discussed in the previous section, the evidence strongly supports such findings. Thus, the EPA has found, in the alternative, that this category of sources contributes significantly to air pollution which may be reasonably anticipated to endanger public health and welfare.

C. Affected Units

We generally refer to fossil fuel-fired electric generating units that would be subject to a CAA section 111 emission standard as ''affected'' or ''covered'' sources, units, facilities or simply as EGUs. An EGU is any boiler, IGCC unit, or combustion turbine (in either simple cycle or combined cycle configuration) that meets the applicability criteria. Affected EGUs include those that commenced construction after January 8, 2014, and meet the specified applicability criteria and, for modifications and reconstructions, EGUs that commenced those activities after June 18, 2014, and meet the specified applicability criteria.

To be considered an EGU, the unit must: (1) Be capable of combusting more than 250 MMBtu/h (260 GJ/h) heat input of fossil fuel; [112] and (2) serve a generator capable of supplying more than 25 MW net to a utility distribution system (*i.e.,* for sale to the grid).[113] However, we are not finalizing CO_2 standards for certain EGUs. The EGUs that are not covered by the standards we are finalizing in this rule include: (1) Non-fossil fuel units subject to a federally enforceable permit that limits the use of fossil fuels to 10 percent or less of their heat input capacity on an annual basis; (2) combined heat and power (CHP) units that are subject to a federally enforceable permit limiting annual net-electric sales to no more than the unit's design efficiency multiplied by its potential electric output, or 219,000 MWh or less, whichever is greater; (3) stationary combustion turbines that are not physically capable of combusting natural gas (*e.g.,* not connected to a natural gas pipeline); (4) utility boilers and IGCC units that have always been subject to a federally enforceable permit limiting annual net-electric sales to one-third or less of their potential electric output (*e.g.,* limiting hours of operation to less than 2,920 hours annually) or limiting annual electric sales to 219,000 MWh or less; (5) municipal waste combustors that are subject to subpart Eb of this part; and (6) commercial or industrial solid waste incineration units subject to subpart CCCC of this part.

D. Units Not Covered by This Final Rule

As described in the previous section, the EPA is not issuing standards of performance for certain types of sources—specifically, dedicated non-fossil fuel-fired (*e.g.,* biomass) units and industrial CHP units, as well as certain projects under development. This section discusses these sources and our rationale for not issuing standards for them. Because the rationale applies to both steam generating units and combustion turbines, we are describing it here rather than in the separate steam generating unit and combustion turbine discussions. We discuss the proposed applicability criteria, the topics where the agency solicited comment, a brief summary of the relevant comments, and the rationale for the final applicability approach for these sources.

1. Dedicated Non-fossil Fuel Units

The proposed applicability for newly constructed EGUs included those that primarily combust fossil fuels (*e.g.,* coal, oil, and natural gas). The proposed applicability criteria were that affected units must burn fossil fuels for more than 10 percent of the unit's total heat input, on average, over a 3-year period.[114] Under the proposed approach, applicability under the final NSPS for CO_2 emissions could have changed on an annual basis depending on the composition of fuel burned. We solicited comment on several aspects of the proposed applicability criteria for non-fossil fuel units. Specifically, we solicited comment on a broad applicability approach that would include non-fossil fuel-fired units as affected units, but that would impose an alternate standard when the unit fires fossil fuels for 10 percent or less of the heat input during the 3-year applicability-determination period. We solicited comment on whether, if such a subcategory is warranted, the applicability-determination period for the subcategory should be 1-year or a 3-year rolling period. We also solicited comment on whether the standard for such a subcategory should be an alternate numerical limit or ''no emission standard.''

While the proposed exemption applied to all non-fossil fuels, most commenters focused on biomass-specific issues. Many commenters supported an exclusion for biomass-fired units that fire no more than 10 percent fossil fuels. Some commenters suggested that the exclusion for biomass-fired units should be raised to a 25 percent fossil fuel-use threshold.

Many commenters supported the proposed 3-year averaging period for the fossil fuel-use criterion because it provides greater flexibility for operators to use fossil fuels when supply chains for the primary non-fossil fuels are disrupted, during unexpected malfunctions of the primary non-fossil fuel handling systems, or when the unit's maximum generating capacity is required by system operators for reliability reasons. Many commenters supported the 3-year averaging period because it is consistent with the final requirements under the EPA's Mercury and Air Toxics Standards (MATS) and would allow non-fossil fuel-fired units to use some fossil fuels for flame stabilization without triggering applicability. Some commenters requested that the EPA clarify the method an operator should use during the first 3 years of operations to determine if a particular unit will meet the 10 percent fossil fuel-use threshold. Others asked whether or not an affected facility has a compliance obligation during the first 3-year period and, if an

[111] See, *e.g., American Trucking Assn's* v. *EPA,* 175 F.3d 1027, 1055, rev'd on other grounds sub. nom. *Whitman* v. *Am. Trucking Assn's,* 531.U.S. 457 (because fine particulate matter ($PM_{2.5}$) was already included as a sub-set of the listed pollutant particulate matter, it was not a new pollutant necessitating a new listing).

[112] We refer to the capability to combust 250 MMBtu/h of fossil fuel as the ''base load rating criterion.'' Note that 250 MMBtu/h is equivalent to 73 MW or 260 GJ/h heat input.

[113] We refer to the capability to supply 25 MW net to the grid as the ''total electric sales criterion.''

[114] We refer to the fraction of heat input derived from fossil fuels as the ''fossil fuel-use criterion.''

affected facility does not meet the 10 percent fossil fuel-use threshold during several 12-month periods during the first 3 years, whether compliance calculations would be required for such 12-month periods. Other commenters had concerns with the 3-year averaging period, stating that a source would no longer be subject to the NSPS if it fell below the threshold for any of the applicability metrics that the EPA proposed to calculate on a 3-year (or, in some cases, annual) basis. They argued that this would create a situation in which no one would know whether a particular plant will be subject to the standards until years after the emissions had already occurred. Some commenters were concerned that plants operating near the threshold could move in and out of the regulatory system, which would provide complications for compliance, enforcement, and permitting.

After considering these comments, the EPA has concluded that the proposed fossil fuel-use criterion based on the actual amount of fossil fuel burned is not an ideal approach to determine applicability. As commenters pointed out, facilities, permitting authorities, and the public would not know when construction is commenced whether a facility will be subject to the final NSPS, and after operation has commenced, a unit could move in and out of applicability each year. The intent of this rulemaking is to establish CO_2 standards for fossil fuel-fired EGUs, not for non-fossil fuel-fired EGUs. Therefore, to simplify compliance and establish CO_2 standards for only those sources which we set out to regulate, we are finalizing a fossil fuel-use criterion that will exempt dedicated non-fossil units. Specifically, units that are capable of burning 50 percent or more non-fossil fuel are exempt from the final standards so long as they are subject to a federally enforceable permit that limits their use of fossil fuels to 10 percent or less of their heat input capacity on an annual basis. This approach establishes clear applicability criteria and avoids the prospect of units moving in and out of applicability based on their actual fuel use in a given year. Consistent with the applicability approach in the steam generating unit criteria pollutant NSPS, subpart Da, the final fossil fuel-use criterion does not include ''constructed for the purpose of'' language. Therefore, an owner or operator could change a unit's applicability in the future by seeking a modification of the unit's permit conditions. A unit with the appropriate permit limitation will not be subject to the requirements in this rulemaking. Similarly, an existing unit that takes a permit limitation restricting fossil-fuel use would no longer be an affected unit for the purposes of 111(d) state plans. This is consistent with our intent to reduce GHG emissions from fossil fuel-fired EGUs.

We considered using either an annual or 3-year average for calculating compliance with the final fossil fuel-use criterion. Ultimately, we concluded that an annual average would provide sufficient flexibility for dedicated non-fossil units to combust fossil fuels for flame stabilization and other ancillary purposes, while maintaining consistency with the 12-month compliance periods used for most permit limitations. A 3-year average potentially would allow units to combust a significant quantity of fuels in a given year, leading to higher CO_2 emissions, so long as they curtailed fossil-fuel use in a later year. This would defeat the purpose of the criterion, which is to exempt dedicated non-fossil units only. Finally, we are finalizing the 10 percent fossil-fuel use threshold in relation to a unit's heat input capacity rather than its actual heat input, which is consistent with past approaches we have taken under the industrial boiler criteria pollutant NSPS.

2. Industrial CHP Units

Another approach to generating electricity is the use of CHP units. A CHP unit can use a boiler, combustion turbine, reciprocating engine, or various other generating technologies to generate electricity and useful thermal energy in a single, integrated system. CHP units are generally more efficient than conventional power plants because the heat that is normally wasted in a conventional power generation cooling system (*e.g.,* cooling towers) is instead recovered as useful thermal output. While the EPA did propose some applicability provisions specific to CHP units (*e.g.,* subtract purchased power of adjacent facilities when determining total electric sales), in general, the proposed applicability criteria for electric-only units and CHP units were similar. The intent of the proposed total and percentage electric sales criteria was to cover only utility CHP units, not industrial CHP units. To the extent that the proposal's applicability provisions would have the effect of covering industrial CHP units, we solicited comment on an appropriate applicability exemption, and the criteria for that exemption, for highly efficient CHP facilities.

Many commenters supported the exclusion of CHP units as a means of encouraging capital investments in highly efficient and reliable distributed generation technologies. These commenters recommended that the EPA adopt an explicit exemption for CHP units at facilities that are classified as industrial (*e.g.,* gas-fired CHPs within SIC codes 2911—petroleum refining, 13—oil and gas extraction, and other industrial SIC codes as appropriate). They also stated that the EPA should exclude CHP units that have an energy savings of 10 percent or more compared to separate heat and power. One commenter suggested that the final rule should cover only industrial-commercial-institutional CHP units that supply, on a net basis, more than two-thirds of their potential combined thermal and electric energy output and more than 450,000 MWh net-electric output to a utility power distribution system on an annual basis for five consecutive calendar years. The commenter also suggested that CHP units which have total thermal energy production that approaches or exceeds their total electricity production should be exempted.

Other commenters suggested exempting CHP units by fuel type or based on the definition of potential electric output. For example, some commenters suggested modifying the percentage electric sales threshold to be based on net system efficiency (including useful thermal output) rather than the rated net-electric-output efficiency. They also suggested that the applicability criteria should use a default efficiency of 50 percent for CHP units. Some commenters suggested that a CHP unit should not be considered an affected EGU if 20 percent or more of its total gross or net energy output consisted of useful thermal output on a 3-year rolling average basis. Other commenters said that highly efficient CHP units that achieve an overall efficiency level of 60 to 70 percent or higher should be excluded from applicability.

The intent of this rulemaking is to cover only utility CHP units, because they serve essentially the same purpose as electric-only EGUs (*i.e.,* the sale of electricity to the grid). Industrial CHP units, on the other hand, serve a different primary purpose (*i.e.,* providing useful thermal output with electric sales as a by-product). With these facts in mind and after considering the comments, the EPA has concluded that it is appropriate to consider two factors for the final CHP exemption: (1) Whether the primary purpose of the CHP unit is to provide useful thermal output rather than electricity and (2) whether the CHP unit is highly efficient and thus achieves environmental benefits.

We rejected many of the approaches suggested by the commenters because they did not achieve one or both of the factors we identified. Specifically, the EPA has concluded that SIC code classification is not a sufficient indicator of the purpose (*i.e.,* it does not correlate to useful thermal output) or environmental benefits (*i.e.,* efficiency) of a unit. Further, an exemption based on SIC code could result in circumvention of the intended applicability. For example, this approach would allow a new EGU to locate near an industrial site, provide a trivial amount of useful thermal output to that site, sell electricity to the grid, and nonetheless avoid applicability. Similarly, increasing the electric sales criteria to two-thirds of potential electric output and 450,000 MWh would essentially amount to a blanket exemption that tells us nothing about the primary purpose or efficiency of the unit.

On the other hand, exemptions based on useful thermal output being greater than 20 percent of total output, thermal output being greater than electric output, or overall design efficiency value would identify whether the primary purpose of a unit is to generate thermal output, but they would not recognize the environmental benefits of highly efficient CHP units. While overall efficiency may appear to be a good indicator of environmental benefits, this is not always the case with CHP units. Overall efficiency is a function of both efficient design and the power to heat ratio (the amount of electricity relative to the amount of useful thermal output). For example, boiler-based CHP units tend to produce large amounts of useful thermal output relative to electric output and tend to have high overall efficiencies. For units producing primarily useful thermal output, the equivalent separate heat and power efficiency (*i.e.,* the theoretical overall efficiency if the electricity and useful thermal output were produced by a stand-alone EGU and stand-alone boiler) would approach that of a stand-alone boiler (*e.g.,* 80 percent). However, combustion turbine-based CHP units tend to produce relatively equal amounts of electricity and useful thermal output. In this case, the equivalent separate heat and power efficiency would be closer to 65 percent. Therefore, an exemption based on overall efficiency is not an indication of the fuel savings a CHP unit will achieve relative to separate heat and power. Further, this approach would encourage the development of CHP units that just meet the efficiency exemption criterion and would still cover many combustion turbine-based industrial CHP units. Conversely, while an exemption based on fuel savings relative to separate heat and power would recognize the environmental benefit of highly efficient CHP units, it would not consider the primary purpose of the CHP unit.

In the end, the EPA has concluded that maintaining the proposed percentage electric sales criterion with two adjustments addresses both factors with which we are concerned. First, we are changing the definition of ''potential electric output'' to be based on overall net efficiency at the maximum electric production rate, instead of just electric-only efficiency. Second, we are changing the percentage electric sales criterion to reflect the sliding scale, which is the overall design efficiency, calculated at the maximum useful thermal rating of the CHP unit (*e.g.,* a CHP unit with a extraction condensing steam turbine would determine the efficiency at the maximum extraction/bypass rate), of the unit multiplied by the unit's potential electric output instead of one-third of potential electric output as proposed. This approach recognizes the primary purpose of industrial CHP units by providing a more generous percentage electric sales exemption to CHP units with high thermal output. As described previously, CHP units with high thermal loads tend to be more efficient and will therefore have a higher allowable percentage electric sales. By amending both the definition of ''potential electric output'' and the electric sales threshold, we assure that CHP units that primarily produce useful thermal output are exempted as industrial CHP units even if they are selling all of their electric output to the grid. As the relative amount of electricity generated by the CHP unit increases, efficiency will generally decrease, thus limiting allowable electric sales before applicability is triggered. This approach also recognizes the environmental benefits of increased efficiency by encouraging industrial CHP units to be designed as efficiently as possible to take advantage of the higher electric sales permitted by the sliding scale.

In conclusion, a CHP unit will be an affected source unless it is subject to a federally enforceable permit that limits annual total electric sales to less than or equal to the unit's design efficiency multiplied by its potential electric output or 219,000 MWh,[115] whichever is greater. This final applicability criterion will only cover CHP units that condense a significant portion of steam generated by the unit and use the electric power generated as a result of condensing that steam to supply electric power to the grid. CHP facilities that do not have a condensing steam turbine (*e.g.,* combustion turbine-based CHP units without a steam turbine and boiler-based systems with a backpressure steam turbine) would generally not be physically capable of selling enough electricity to meet the applicability criterion, even if they sold 100 percent of the electricity generated and did not subtract out the electricity used by the thermal host(s). The EPA has concluded that this is appropriate because these sources are industrial by design and provide mostly useful thermal output.

CHP facilities with a steam extraction condensing steam turbine will determine their potential electric output based on their efficiency on a net basis at the maximum electric production rate at the base load heat input rating (*e.g.,* the CHP is condensing as much steam as possible to create electricity instead of using it for useful thermal output). We have concluded that it is necessary for CHP units with extraction condensing steam turbines to calculate their potential electric output at the maximum condensing level to avoid circumvention of the applicability criteria. For example, to avoid applicability a CHP unit could locate next to an industrial host and have the capability of selling significant quantities of useful thermal output without ever actually intending to supply much, if any, useful thermal output to the industrial host. If we calculated the potential electric output at the maximum level of thermal output, this type of CHP unit could operate at full condensing mode at base load conditions for the entire year and still not exceed the electric sales threshold. During the permitting process, the owner or operator will be able to determine if the unit is subject to the final standards in this rule.

New EGUs with only limited useful thermal output will be subject to the final standards, but the vast majority of new CHP units will be classified as industrial CHP and will not be subject to the final standards. The EPA has concluded that this approach is similar to exempting CHP facilities that sell less than half of their total output (electricity plus thermal), but has the benefit of accounting for overall design efficiency.

[115] The EPA has concluded that it is appropriate to maintain the 219,000 MWh total electric sales criterion for combustion turbine based CHP units to avoid potentially covering smaller industrial CHP units.

This approach both limits applicability to the industrial CHP units and encourages the installation of the most efficient CHP systems because more efficient designs will be able to have higher permitted electric sales while not being subject to the CO_2 standards included in this rulemaking.

3. Municipal Waste Combustors and Commercial and Industrial Solid Waste Incinerators

The purpose of this rulemaking is to establish CO_2 standards for fossil fuel-fired EGUs. Municipal waste combustors and commercial and industrial solid waste incinerators typically have not been included in this source category. Therefore, even if one of these types of units meets the general heat input and electric sales criteria, we are not finalizing CO_2 emission standards for municipal waste combustors subject to subpart Eb of this part and commercial and industrial solid waste incinerators subject to subpart CCCC of this part.

4. Certain Projects Under Development

The EPA proposed that a limited class of projects under development should not be subject to the proposed standards. These were planned sources that may be capable of commencing construction (within the meaning of section 111(a)) shortly after the standard's proposal date, and so would be classified as new sources, but which have a design which would be incapable of meeting the proposed standard of performance. See 79 FR 1461 and CAA section 111(a)(2). The EPA proposed that these sources would not be subject to the generally-applicable standard of performance, but rather would be subject to a unit-specific permitting determination if and when construction actually commences. The EPA indicated that there could be three sources to which this approach could apply, and further indicated that the EPA could ultimately adopt the generally-applicable standard of performance for these sources (if actually constructed). 79 FR 1461.

As explained at Section III.J below, the EPA is finalizing this approach in this final rule. We again note that these sources, if and when constructed, could be ultimately subject to the 1,400 lb CO_2/MWh-g standard, especially if there is no engineering basis, or demonstrated action in reliance, showing that the new source could not meet that standard.

E. Coal Refuse

In the April 2012 proposal, we solicited comment on subcategorizing and exempting EGUs that burn over 75 percent coal refuse on an annual basis. Multiple commenters supported the exemption, citing numerous environmental benefits of remediating coal refuse piles. Observing that coal refuse-fired EGUs typically use fluidized bed technologies, other commenters disagreed with any exemption, specifically citing the N_2O emissions from fluidized bed boilers. In light of the environmental benefits of remediating coal refuse piles cited by commenters, the limited amount of coal refuse, and the fact that a new coal refuse-fired EGU would be located in close proximity to the coal refuse pile, we sought additional comments regarding a subcategory for coal refuse-fired EGUs in the January 2014 proposal. Specifically, we requested additional information on the net environmental benefits of coal refuse-fired EGUs and information to support an appropriate emissions standard for coal refuse-fired EGUs. One commenter on the April 2012 proposal stated that existing coal refuse piles are naturally combusting at a rate of 0.3 percent annually, and we requested comment on this rate and the proper approach to account for naturally occurring emissions from coal refuse piles in the January 2014 proposal.

Commenters said that a performance standard is not feasible for coal refuse CFBs since there is no economically feasible way to capture CO_2 through a conveyance designed and constructed to capture CO_2. Commenters suggested that the EPA establish BSER for GHGs at modified coal refuse CFBs as a boiler tune-up that must be performed at least every 24 months. Commenters stated that the EPA should exempt coal refuse CFB units relative to their CO_2 emissions to the extent that these units offset the uncontrolled ground level emissions from spontaneous combustion of legacy coal refuse stockpiles and noted that the mining of coal waste not only produces less emissions in the long term, but also helps to reclaim land that is currently used to store coal waste. In contrast, one commenter saw no legitimate basis for coal refuse to be subcategorized and stated that it should be treated in the same manner as all other coal-fired EGUs.

The EPA has concluded that an explicit exemption or subcategory specifically for coal refuse-fired EGUs is not appropriate. The costs faced by coal refuse facilities to install CCS are similar to coal-fired EGUs burning any of the primary coals, and the final applicable requirements and standards in the rule do not preclude the development of new coal refuse-fired units without CCS. Specifically, we are not finalizing CO_2 standards for industrial CHP units. Many existing coal refuse-fired units are relatively small and designed as CHP units. Due to the expense of transporting coal refuse long distances, we anticipate that any new coal refuse-fired EGU would be relatively small in size. Moreover, sites with sufficient thermal demand exist such that the unit could be designed as an industrial CHP facility and the requirements of this rule would not apply.

F. Format of the Output-Based Standard

1. Net and Gross Output-Based Standards

For all newly constructed units, the EPA proposed standards as gross output emission rates consistent with current monitoring and reporting requirements under 40 CFR part 75.[116] For a non-CHP EGU, gross output is the electricity generation measured at the generator terminals. However, we solicited comment on finalizing equivalent net-output-based standards either as a compliance alternative or in lieu of the proposed gross-output-based standards. Net output is the gross electrical output less the unit's total parasitic (*i.e.,* auxiliary) power requirements. A parasitic load for an EGU is a load or device powered by electricity, steam, hot water, or directly by the gross output of the EGU that does not contribute electrical, mechanical, or useful thermal output. In general, parasitic energy demands include less than 7.5 percent of non-IGCC and non-CCS coal-fired station power output, approximately 15 percent of non-CCS IGCC-based coal-fired station power output, and about 2.5 percent of non-CCS NGCC power output. The use of CCS increases both the electric and steam parasitic loads used internal to the unit, and these outputs are not considered when determining the emission rate. Net output is used to recognize the environmental benefits of: (1) EGU designs and control equipment that use less auxiliary power; (2) fuels that require less emissions control equipment; and (3) higher efficiency motors, pumps, and fans. For modified and reconstructed combustion turbines, the EPA also proposed standards as gross output emission rates, but solicited comment on finalizing net output standards. The rationale was that due to the low auxiliary loads in non-CCS NGCC designs, the difference between a gross-output standard and a net-output standard has a limited

[116] 79 FR 1447–48.

impact on environmental performance. Auxiliary loads are more significant for modified and reconstructed boilers and IGCC units, and the EPA proposed standards on a net output basis for these units. The rationale included that this would enable owners/operators of these types of units to pursue projects that reduce auxiliary loads for compliance purposes. However, the EPA solicited comment on finalizing the standards on a gross-output basis. We also proposed to use either gross-output or net-output bases for each respective subcategory of EGUs (*i.e.,* utility boilers, IGCC units, and combustion turbines) consistently across all CAA section 111(b) standards for new, modified, and reconstructed EGUs.

Many commenters supported gross-output-based standards, maintaining that a net-output standard penalizes the operation of air pollution control equipment. Several commenters disagreed with the agency's proposed rationale that a net-output standard would provide incentive to minimize auxiliary loads. The commenters believe utility commissions and existing economic forces already provide utilities with appropriate incentives to properly manage all of these factors. Some commenters supported a gross-output-based standard because variations in site conditions (*e.g.,* available natural gas pressure, available cooling water sources, and elevation) will likely penalize some owners and benefit others simply through variations in their particular plant-site conditions if a net basis is used. Several commenters stated that if the final rule includes a net-output-based standard, it should be included as an option in conjunction with a gross-output-based option.

Several commenters opposed net-output-based standards because they believe it is difficult to accurately determine the net output of an EGU. They pointed out that many facilities have transformers that support multiple units at the facility, making unit-level reporting difficult. These commenters also stated that station electric services may come from outside sources to supply certain ancillary loads. One commenter stated that the benefit of switching to net-output-based standards would be small and would not justify the substantial complexities in both defining and implementing such a standard. Conversely, other commenters stated that net-metering is a well-established technology that should be required, particularly for newly constructed units.

Other commenters, however, maintained that the final rule should strictly require compliance on a net output-basis. They believe that this is the only way for the standards to minimize the carbon footprint of the electricity delivered to consumers. These commenters believe that, at a minimum, net-output-based standards should be included as an option in the final rule.

We are only finalizing gross-output-based standards for utility boilers and IGCC units. Providing an alternate net-output-based standard that is based on gross-output-based emissions data and an assumed auxiliary load is most appropriate when the auxiliary load can be reasonably estimated and the choice between the net- and gross-output-based standard will not impact the identified BSER. For example, the auxiliary load for combustion turbines is relatively fixed and small, approximately 2.5 percent, so the choice between a gross and net-output-based standard will not substantially impact technology choices. However, in the case of utility boilers, we have concluded that we do not have sufficient information to establish an appropriate net-output-based standard that would not impact the identified BSER for these types of units. The BSER for newly constructed steam generating units is based on the use of partial CCS. However, unlike the case for combustion turbines, owners/operators of utility boilers have multiple technology pathways available to comply with the actual emission standard. The choice of both control technologies and fuel impact the overall auxiliary load. For example, a coal-fired hybrid EGU (*e.g.,* one that includes integrated solar thermal equipment for feedwater heating or steam augmentation) or a coal-fired EGU co-firing natural gas would have lower non-CCS related auxiliary loads and, because the amount of CCS needed to comply with the standard would also be smaller, the CCS auxiliary loads would also be reduced. Therefore, we cannot identify an appropriate assumed auxiliary load to establish an equivalent net-output-based standard. In addition, many IGCC facilities (which could be used as an alternative technology for complying with the standard of performance; see Sections IV.B and V.P below) have been proposed or are envisioned as co-production facilities (*i.e.,* to produce useful by-products and chemicals along with electricity). As noted in the proposal, we have concluded that predicting the net electricity at these co-production facilities would be more challenging to implement under these circumstances.

In contrast, based on further evaluation and review of issues raised by commenters, the EPA is finalizing the CO_2 standard for combustion turbine EGUs in a format that is similar to the current NSPS format for criteria pollutants. The default final standards establish a gross-output-based standard. This allows owners/operators of new combustion turbines to comply with the CO_2 emissions standard under part 60 using the same data currently collected under part 75.[117] However, many permitting authorities commented persuasively that the environmental benefits of using net-output-based standards can outweigh any additional complexities for particular units, and have indeed adopted net-output standards in recent GHG operating permits for combustion turbines. We expect this trend to continue and have concluded that it is appropriate to support the expanded use of net-output-based standards, and therefore are allowing certain sources to elect between gross output-based and net-output-based standards. Only combustion turbines are eligible to make this election.

The rule specifies an alternative net-output-based standard of 1,030 lb CO_2/MWh-n for combustion turbines. This standard is equivalent to the otherwise-applicable gross-output-based standard of 1,000 lb CO_2/MWh-g.[118]

The procedures for requesting this alternative net-output-based standard require the owner or operator to petition the Administrator in writing to comply with the alternate applicable net-output-based standard. If the Administrator grants the petition, this election would be binding and would be the unit's sole means of demonstrating compliance. Owners or operators complying with the net-output-based standard must similarly petition the Administrator to switch back to complying with the gross-output-based standard.

2. Useful Thermal Output

For CHP units, useful thermal output is also used when determining the emission rate. Previous rulemakings issued by the EPA have prescribed various ''discount factors'' of the measured useful thermal output to be used when determining the emission rate. We proposed that 75 percent credit is the appropriate discount factor for useful thermal output, and we solicited

[117] Additionally, having an NSPS standard that is measured using the same monitoring equipment as required under the operating permit minimizes compliance burden. If a combustion turbine were subject to both a gross and net emission limit, more expensive higher accuracy monitoring could be required for both measurements.

[118] Assuming a 3 percent auxiliary load for the NGCC system.

comment on a range from two-thirds to three-fourths credit for useful thermal output in the proposal for newly constructed units and two-thirds to one hundred percent credit in the proposal for modified and reconstructed units. The 75 percent credit was based on matching the emission rate, but not the overall emissions, of a hypothetical CHP unit to the proposed emission rate.

Many commenters said that in order to fully account for the environmental benefits of CHP and to reflect the environmental benefits of CHP, the EPA should allow 100 percent of the useful thermal output from CHP units. Commenters noted that providing 100 percent credit for useful thermal output is consistent with the past practice of the EPA in the stationary combustion turbine criteria pollutant NSPS and state approaches for determining emission rates for CHP units.

Based on further consideration and review of the comments submitted, we are finalizing 100 percent credit for useful thermal output for all newly constructed, modified, and reconstructed CHP sources. We have concluded that this is appropriate because, at the same reported emission rate, a hypothetical CHP unit would have the same overall GHG emissions as the combined emission rate of separate heat and power facilities. Any discounting of useful thermal output could distort the market and discourage the development of new CHP units. Full credit for useful thermal output appropriately recognizes the environmental benefit of CHP.

G. CO_2 Emissions Only

The air pollutant regulated in this final action is greenhouse gases. However, the standards in this rule are expressed in the form of limits on only emissions of CO_2, and not the other constituent gases of the air pollutant GHGs.[119] We are not establishing a limit on aggregate GHGs or separate emission limits for other GHGs (such as methane (CH_4) or nitrous oxide (N_2O)) as other GHGs represent less than 1 percent of total estimated GHG emissions (as CO_2e) from fossil fuel-fired electric power generating units.[120] Notwithstanding this form of the standard, consistent with other EPA regulations addressing GHGs, the air pollutant regulated in this rule is GHGs.[121]

H. Legal Requirements for Establishing Emission Standards

1. Introduction

In the January 2014 proposal, we described the principal legal requirement for standards of performance under CAA section 111(b), which is that the standards of performance must consist of standards for emissions that reflect the degree of emission limitation achievable though the application of the ''best system of emission reduction . . . adequately demonstrated,'' taking into account cost and any non-air quality health and environment impact and energy requirements. We noted that the D.C. Circuit has handed down numerous decisions that interpret this CAA provision, including its component elements, and we reviewed that case law in detail.[122]

We received comments on our proposed interpretation, and in light of those comments, in this rule, we are clarifying our interpretation in certain respects. We discuss our interpretation below.[123]

2. CAA Requirements and Court Interpretation

As noted above, the CAA section 111 requirements that govern this rule are as follows: As the first step towards establishing standards of performance, the EPA ''shall publish . . . a list of categories of stationary sources . . . [that] cause[ ], or contribute[ ] significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare.'' CAA section 111(b)(1)(A). Following that listing, the EPA ''shall publish proposed regulations, establishing federal standards of performance for new sources within such category'' and then ''promulgate . . . such standards'' within a year after proposal. CAA section 111(b)(1)(B). The EPA ''may distinguish among classes, types, and sizes within categories of new sources for the purpose of establishing such standards.'' CAA section 111(b)(2). The term ''standard of performance'' is defined to ''mean[ ] a standard for emissions . . . achievable through the application of the best system of emission reduction which [considering cost, non-air quality health and environmental impact, and energy requirements] the Administrator determines has been adequately demonstrated.'' CAA section 111(a)(1).

As noted in the January 2014 proposal, Congress first included the definition of ''standard of performance'' when enacting CAA section 111 in the 1970 Clean Air Act Amendments (CAAA), amended it in the 1977 CAAA, and then amended it again in the 1990 CAAA to largely restore the definition as it read in the 1970 CAAA. It is in the legislative history for the 1970 and 1977 CAAAs that Congress primarily addressed the definition as it read at those times, and that legislative history provides guidance in interpreting this provision.[124] In addition, the D.C. Circuit has reviewed rulemakings under CAA section 111 on numerous occasions during the past 40 years, handing down decisions dated from 1973 to 2011,[125] through which the

[119] As noted above, in the Endangerment Finding, the EPA defined the relevant ''air pollution'' as the atmospheric mix of six long-lived and directly-emitted greenhouse gases: carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6). 74 FR 66497.

[120] EPA Greenhouse Gas Reporting Program; *www.epa.gov/ghgreporting/.*

[121] See 77 FR 31257–30 (June 3, 2010).

[122] 79 FR 1430, 1462 (January 8, 2014).

[123] We also discuss our interpretation of the requirements for standards of performance and the BSER under section 111(d), for existing sources, in the section 111(d) rulemaking that the EPA is finalizing with this rule. Our interpretations and applications of these requirements in the two rulemakings are generally consistent with each other except to the extent that they reflect distinctions between new and existing sources. For example, the BSER for new industrial facilities, which are expected to have lengthy useful lives, should include, at a minimum, the most advanced pollution controls available, but for existing sources, the additional costs of retrofit may render those controls too expensive.

[124] In the 1970 CAAA, Congress defined ''standard of performance,'' under section 111(a)(1), as—a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction) the Administrator determines has been adequately demonstrated.

In the 1977 CAAA, Congress revised the definition to distinguish among different types of sources, and to require that for fossil fuel-fired sources, the standard: (i) Be based on, in lieu of the ''best system of emission reduction . . . adequately demonstrated,'' the ''best technological system of continuous emission reduction . . . adequately demonstrated;'' and (ii) require a percentage reduction in emissions. In addition, in the 1977 CAAA, Congress expanded the parenthetical requirement that the Administrator consider the cost of achieving the reduction to also require the Administrator to consider ''any nonair quality health and environment impact and energy requirements.''

In the 1990 CAAA, Congress again revised the definition, this time repealing the requirements that the standard of performance be based on the best technological system and achieve a percentage reduction in emissions, and replacing those provisions with the terms used in the 1970 CAAA version of section 111(a)(1) that the standard of performance be based on the ''best system of emission reduction . . . adequately demonstrated.'' This 1990 CAAA version is the current definition. Even so, because parts of the definition as it read under the 1977 CAAA were retained in the 1990 CAAA, the explanation in the 1977 CAAA legislative history, and the interpretation in the case law, of those parts of the definition in the case law remain relevant to the definition as it reads today.

[125] *Portland Cement Ass'n* v. *Ruckelshaus,* 486 F.2d 375 (D.C. Cir. 1973); *Essex Chemical Corp.* v. *Ruckelshaus,* 486 F.2d 427, (D.C. Cir. 1973);

Continued

Court has developed a body of case law that interprets the term ''standard of performance.''

3. Key Elements of Interpretation

By its terms, the definition of ''standard of performance'' under CAA section 111(a)(1) provides that the emission limits that the EPA promulgates must be ''achievable'' by application of a ''system of emission reduction'' that the EPA determines to be the ''best'' that is ''adequately demonstrated,'' ''taking into account . . . cost . . . nonair quality health and environmental impact and energy requirements.'' The D.C. Circuit has stated that, in determining the ''best'' system, the EPA must also take into account ''the amount of air pollution'' [126] reduced and the role of ''technological innovation.'' [127] The Court has emphasized that the EPA has discretion in weighing those various factors.[128] [129]

Our overall approach to determining the BSER, which incorporates the various elements, is as follows: First, the EPA identifies the ''system[s] of emission reduction'' that have been ''adequately demonstrated'' for a particular source category. Second, the EPA determines the ''best'' of these systems after evaluating extent of emission reductions, costs, any non-air health and environmental impacts, and energy requirements. And third, the EPA selects an achievable standard for emissions—here, the emission rate—based on the performance of the BSER. The remainder of this subsection discusses the various elements in that analytical approach.

a. ''System[s] of Emission Reduction . . . Adequately Demonstrated''

The EPA's first step is to identify ''system[s] of emission reduction . . . adequately demonstrated.'' For the reasons discussed below, for the various types of newly constructed, modified, and reconstructed sources in this rulemaking, the EPA focused on efficient generation, add-on controls, efficiency improvements, and clean fuels as the systems of emission reduction.

An ''adequately demonstrated'' system, according to the D.C. Circuit, is ''one which has been shown to be reasonably reliable, reasonably efficient, and which can reasonably be expected to serve the interests of pollution control without becoming exorbitantly costly in an economic or environmental way.'' [130] It does not mean that the system ''must be in actual routine use somewhere.'' [131] Rather, the Court has said, ''[t]he Administrator may make a projection based on existing technology, though that projection is subject to the restraints of reasonableness and cannot be based on 'crystal ball' inquiry.'' [132] Similarly, the EPA may ''hold the industry to a standard of improved design and operational advances, so long as there is substantial evidence that such improvements are feasible.'' [133] Ultimately, the analysis ''is partially dependent on 'lead time,' '' that is, ''the time in which the technology will have to be available.'' [134] Per CAA section 111(e), standards of performance under CAA section 111(b) are applicable immediately after the effective date of their promulgation.

(1) Technical Feasibility of the Best System of Emission Reduction

As the January 2014 proposal indicates, the requirement that the standard for emissions be ''achievable'' based on the ''best system of emission reduction . . . adequately demonstrated'' indicates that one of the requirements for the technology or other measures that the EPA identifies as the BSER is that the measure must be technically feasible. See 79 FR 1430, 1463 (January 8, 2014).

b. ''Best''

In determining which adequately demonstrated system of emission reduction is the ''best,'' the EPA considers the following factors:

(1) Costs

Under CAA section 111(a)(1), the EPA is required to take into account ''the cost of achieving'' the required emission reductions. As described in the January 2014 proposal,[135] in several cases the D.C. Circuit has elaborated on this cost factor and formulated the cost standard in various ways, stating that the EPA may not adopt a standard the cost of which would be ''exorbitant,'' [136] ''greater than the industry could bear and survive,'' [137] ''excessive,'' [138] or ''unreasonable.'' [139] For convenience, in this rulemaking, we use 'reasonableness' to describe costs well within the bounds established by this jurisprudence.[140]

The D.C. Circuit has indicated that the EPA has substantial discretion in its consideration of cost under section 111(a). In several cases, the Court upheld standards that entailed significant costs, consistent with Congress's view 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.'' [141] *See Essex Chemical Corp.* v. *Ruckelshaus,* 486 F.2d 427, 440 (D.C. Cir. 1973); [142] *Portland Cement Association* v. *Ruckelshaus,* 486 F.2d 375, 387–88 (D.C. Cir. 1973); *Sierra Club* v. *Costle,* 657 F.2d 298, 313 (D.C. Cir.

Portland Cement Ass'n v. *EPA,* 665 F.3d 177 (D.C. Cir. 2011). *See also Delaware* v. *EPA,* No. 13–1093 (D.C. Cir. May 1, 2015).

[126] See *Sierra Club* v. *Costle,* 657 F.2d 298, 326 (D.C. Cir. 1981).

[127] See *Sierra Club* v. *Costle,* 657 F.2d at 347.

[128] See *Lignite Energy Council* v. *EPA,* 198 F.3d 930, 933 (D.C. Cir. 1999).

[129] Although section 111(a)(1) may be read to state that the factors enumerated in the parenthetical are part of the ''adequately demonstrated'' determination, the D.C. Circuit's case law appears to treat them as part of the ''best'' determination. See *Sierra Club* v. *Costle,* 657 F.2d at 325–26. It does not appear that those two approaches would lead to different outcomes. In this rule, the EPA is following the D.C. Circuit case law and treating the factors as part of the ''best'' determination.

[130] *Essex Chem. Corp.* v. *Ruckelshaus,* 486 F.2d 427, 433 (D.C. Cir. 1973), *cert. denied,* 416 U.S. 969 (1974).

[131] *Portland Cement Ass'n* v. *Ruckelshaus,* 486 F.2d 375, 391 (D.C. Cir. 1973) (citations omitted) (discussing the Senate and House bills and reports from which the language in CAA section 111 grew).

[132] *Portland Cement Ass'n* v. *Ruckelshaus,* 486 F.2d 375, 391 (D.C. Cir. 1973) (citations omitted).

[133] *Sierra Club* v. *Costle,* 657 F.2d 298, 364 (1981).

[134] *Portland Cement Ass'n* v. *Ruckelshaus,* 486 F.2d 375, 391 (D.C. Cir. 1973) (citations omitted).

[135] 79 FR 1464 (January 8, 2014).

[136] *Lignite Energy Council* v. *EPA,* 198 F.3d 930, 933 (D.C. Cir. 1999).

[137] *Portland Cement Ass'n* v. *EPA,* 513 F.2d 506, 508 (D.C. Cir. 1975).

[138] *Sierra Club* v. *Costle,* 657 F.2d 298, 343 (D.C. Cir. 1981).

[139] *Sierra Club* v. *Costle,* 657 F.2d 298, 343 (D.C. Cir. 1981).

[140] These cost formulations are consistent with the legislative history of section 111. 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. Some commenters asserted that we do not have authority to revise the cost standard as established in the case law, *e.g.,* ''exorbitant,'' ''excessive,'' etc., to a ''reasonableness'' standard that may be considered less protective of the environment. We agree that we do not have authority to revise the cost standard as established in the case law, and we are not attempting to do so here. Rather, our description of the cost standard as ''reasonableness'' is intended to be a convenient term for referring to the cost standard as established in the case law.

[141] 1977 House Committee Report at 184.

[142] The costs for these standards were described in the rulemakings. *See* 36 FR 24876 (December 23, 1971), 37 FR 5767, 5769 (March 21, 1972).

1981) (upholding standard imposing controls on SO_2 emissions from coal-fired power plants when the ''cost of the new controls . . . is substantial'').[143] Moreover, section 111(a) does not provide specific direction regarding what metric or metrics to use in considering costs, again affording the EPA considerable discretion in choosing a means of cost consideration.[144]

As discussed below, the EPA may consider costs on both a source-specific basis and a sector-wide, regional, or nationwide basis. The EPA is finding here that whether costs are considered on a source-specific basis, an industry/national basis, or both, they are reasonable. See Sections V.H and I below.

(2) Non-Air Quality Health and Environmental Impacts

Under CAA section 111(a)(1), the EPA is required to take into account ''any nonair quality health and environmental impact'' in determining the BSER. As the D.C. Circuit has explained, this requirement makes explicit that a system cannot be ''best'' if it does more harm than good due to cross-media environmental impacts.[145] The EPA has carefully considered such cross-media impacts here, in particular potential impacts to underground sources of drinking water posed by CO_2 sequestration, and water use necessary to operate carbon capture systems. See Sections V.N and O below.

(3) Energy Considerations

Under CAA section 111(a)(1), the EPA is required to take into account ''energy requirements.'' As discussed below, the EPA may consider energy requirements on both a source-specific basis and a sector-wide, region-wide, or nationwide basis. Considered on a source-specific basis, ''energy requirements'' entail, for example, the impact, if any, of the system of emission reduction on the source's own energy needs. In this rulemaking, as discussed below in Section V.O.3, the EPA considered the parasitic load requirements of partial CCS. The EPA is finding here that whether energy requirements are considered on a source-specific basis, an industry/national basis, or both, they are reasonable. See Sections V.O.3 and XIII.C.

(4) Amount of Emissions Reductions

At proposal, we noted that although the definition of ''standard of performance'' does not by its terms identify the amount of emissions from the category of sources or the amount of emission reductions achieved as factors the EPA must consider in determining the ''best system of emission reduction,'' the D.C. Circuit has stated that the EPA must in fact do so. *See Sierra Club* v. *Costle,* 657 F.2d 298, 326 (D.C. Cir. 1981) (''we can think of no sensible interpretation of the statutory words ''best . . . system'' which would not incorporate the amount of air pollution as a relevant factor to be weighed when determining the optimal standard for controlling . . . emissions'').[146] The fact that the purpose of a ''system of emission reduction'' is to reduce emissions, and that the term itself explicitly incorporates the concept of reducing emissions, supports the Court's view that in determining whether a ''system of emission reduction'' is the ''best,'' the EPA must consider the amount of emission reductions that the system would yield.[147] Even if the EPA were not required to consider the amount of emission reductions, the EPA has the discretion to do so, on grounds that either the term ''system of emission reduction'' or the term ''best'' may reasonably be read to allow that discretion.

(5) Sector or Nationwide Component of the BSER Factors

As discussed in the January 2014 proposal, another component of the D.C. Circuit's interpretations of CAA section 111 is that the EPA may consider the various factors it is required to consider on a national or regional level and over time, and not only on a plant-specific level at the time of the rulemaking.[148] The D.C. Circuit based this conclusion on a review of the legislative history, stating,

> The Conferees defined the best technology in terms of ''long-term growth,'' ''long-term cost savings,'' effects on the ''coal market,'' including prices and utilization of coal reserves, and ''incentives for improved technology.'' Indeed, the Reports from both Houses on the Senate and House bills illustrate very clearly that Congress itself was using a long-term lens with a broad focus on future costs, environmental and energy effects of different technological systems when it discussed section 111.[149]

The Court has upheld rules that the EPA ''justified . . . in terms of the policies of the Act,'' including balancing long-term national and regional impacts:

> The standard reflects a balance in environmental, economic, and energy consideration by being sufficiently stringent to bring about substantial reductions in SO_2 emissions (3 million tons in 1995) yet does so at reasonable costs without significant energy penalties. . . . By achieving a balanced coal demand within the utility sector and by promoting the development of less expensive SO_2 control technology, the final standard will expand environmentally acceptable energy supplies to existing power plants and industrial sources.
>
> By substantially reducing SO_2 emissions, the standard will enhance the potential for long term economic growth at both the national and regional levels.[150]

Some commenters objected that this case law did not allow the EPA to ignore source-specific impacts (particularly cost impacts) by basing determinations solely on impacts at a regional or national level. In fact, the EPA's consideration of cost, non-air quality impacts, and energy requirements reflect source-specific impacts, as well as (for some considerations) impacts that are sector-wide, regional, or national. See Section V.H.6 below.

c. Achievability of the Standard for Emissions

In the January 2014 proposal, the EPA recognized that the first element of the definition of ''standard of performance'' is that ''the emission limit [*i.e.,* the 'standard for emissions'] that the EPA promulgates must be 'achievable' ''

[143] Indeed, in upholding the EPA's consideration of costs under the provisions of the Clean Water Act authorizing technology-based standards based on performance of a best technology taking costs into account, courts have also noted the substantial discretion delegated to the EPA to weigh cost considerations with other factors. *Chemical Mfr's Ass'n* v. *EPA,* 870 F.2d 177, 251 (5th Cir. 1989); *Association of Iron and Steel Inst.* v. *EPA,* 526 F.2d 1027, 1054 (3d Cir. 1975); *Ass'n of Pacific Fisheries* v. *EPA,* 615 F.2d 794, 808 (9th Cir. 1980).

[144] See, *e.g., Husqvarna AB* v. *EPA,* 254 F.3d 195, 200 (D.C. Cir. 2001) (where CAA section 213 does not mandate a specific method of cost analysis, the EPA may make a reasoned choice as to how to analyze costs).

[145] *Portland Cement* v. *EPA,* 486 F.2d at 384; *Sierra Club* v. *Costle,* 657 F.2d at 331; see also *Essex Chemical Corp.* v. *Ruckelshaus,* 486 F.2d at 439 (remanding standard to consider solid waste disposal implications of the BSER determination).

[146] *Sierra Club* v. *Costle,* 657 F.2d 298 (D.C. Cir. 1981) was governed by the 1977 CAAA version of the definition of ''standard of performance,'' which revised the phrase ''best system'' to read, ''best *technological* system.'' As noted above, the 1990 CAAA deleted ''technological,'' and thereby returned the phrase to how it read under the 1970 CAAA. The court's interpretation of this phrase in *Sierra Club* v. *Costle* to require consideration of the amount of air emissions reductions remains valid for the phrase ''best system.''

[147] See also *NRDC* v. *EPA,* 479 F.3d 875, 880 (D.C. Cir. 2006) (''best performing'' source for purposes of CAA section 112 (d)(3) is source with the lowest emission levels).

[148] 79 FR 1430, 1465 January 8, 2014) (citing *Sierra Club* v. *Costle,* 657 F.2d at 351).

[149] *Sierra Club* v. *Costle,* 657 F.2d at 331 (citations omitted) (citing legislative history).

[150] *Sierra Club* v. *Costle,* 657 F.2d at 327–28 (quoting 44 FR 33583/3–33584/1). In the January 2014 proposal, we explained that although the D.C. Circuit decided *Sierra Club* v. *Costle* before the *Chevron* case was decided in 1984, the D.C. Circuit's decision could be justified under either *Chevron* step 1 or 2. 79 FR 1430, 1466 (January 8, 2014).

based on performance of the BSER. 79 FR 1430, 1463 (January 8, 2014). According to the D.C. Circuit, a standard for emissions is ''achievable'' if a technology can reasonably be projected to be available to new sources at the time they are constructed that will allow them to meet the standard.[151] Moreover, according to the Court, ''[a]n achievable standard is one which is within the realm of the adequately demonstrated system's efficiency and which, while not at a level that is purely theoretical or experimental, need not necessarily be routinely achieved within the industry prior to its adoption.'' [152] To be achievable, a standard ''must be capable of being met under most adverse conditions which can reasonably be expected to recur and which are not or cannot be taken into account in determining the 'cost of compliance.' '' [153] To show that a standard is achievable, the EPA must ''(1) identify variable conditions that might contribute to the amount of expected emissions, and (2) establish that the test data relied on by the agency are representative of potential industry-wide performance, given the range of variables that affect the achievability of the standard.'' [154]

In Sections V.J and IX.D below, we show both that the BSER for new steam generating units and combustion turbines is technically feasible and adequately demonstrated, and that the standards of 1,400 lb CO_2/MWh-g and 1,000 lb CO_2/MWh-g are achievable considering the range of operating variables that affect achievability.

d. Expanded Use and Development of Technology

In the January 2014 proposal, we noted that the D.C. Circuit has made clear that Congress intended for CAA section 111 to create incentives for new technology and therefore that the EPA is required to consider technological innovation as one of the factors in determining the ''best system of emission reduction.'' [155]

The Court grounded its reading in the statutory text.[156] In addition, in the January 2014 proposal, we noted that the Court's interpretation finds additional support in the legislative history.[157] We also explained that the legislative history identifies three different ways that Congress designed CAA section 111 to authorize standards of performance that promote technological improvement: (i) The development of technology that may be treated as the ''best system of emission reduction . . . adequately demonstrated'' under section 111(a)(1); (ii) the expanded use of the best demonstrated technology; and (iii) the development of emerging technology.[158] Even if the EPA were not required to consider technological innovation as part of its determination of the BSER, it would be reasonable for the EPA to consider it, either because technological innovation may be considered an element of the term ''best,'' or because the term ''best system of emission reduction'' is ambiguous as to whether technological innovation may be considered. The interpretation is likewise consistent with the evident purpose of section 111(b) to require new sources to maximize emission reductions using state-of-the-art means of control.

Commenters stated that the requirement to consider technological innovation does not authorize the EPA to identify as the BSER a technology that is not adequately demonstrated. The proposal did not, and we do not in this final rule, claim to the contrary. In any event, as discussed below, the EPA may justify the control technologies identified in this rule as the BSER even without considering the factor of incentivizing technological innovation or development.

e. Agency Discretion

As discussed in the January 2014 proposal, the D.C. Circuit has made clear that the EPA has broad discretion in determining the appropriate standard of performance under the definition in CAA section 111(a)(1), quoted above. Specifically, in *Sierra Club* v. *Costle,* 657 F.2d 298 (D.C. Cir. 1981), the Court explained that ''section 111(a) explicitly instructs the EPA to balance multiple concerns when promulgating a NSPS,'' [159] and emphasized that ''[t]he text gives the EPA broad discretion to weigh different factors in setting the standard.'' [160] In *Lignite Energy Council* v. *EPA,* 198 F.3d 930 (D.C. Cir. 1999), the Court reiterated:

> Because section 111 does not set forth the weight that should be assigned to each of these factors, we have granted the agency a great degree of discretion in balancing them. . . . EPA's choice [of the 'best system'] will be sustained unless the environmental or economic costs of using the technology are exorbitant. . . . EPA [has] considerable discretion under section 111.[161]

f. Lack of Requirement That Standard Must Be Met by All Sources

In the January 2014 proposal, the EPA proposed that, under CAA section 111, an emissions standard may meet the requirements of a ''standard of performance'' even if it cannot be met by every new source in the source category that would have constructed in the absence of that standard. As described in the January 2014 proposal, the EPA based this view on (i) the legislative history of CAA section 111, read in conjunction with the legislative history of the CAA as a whole; (ii) case law under analogous CAA provisions; and (iii) long-standing precedent in the EPA rulemakings under CAA section 111.[162]

[151] *Portland Cement,* 486 F.2d at 391–92. Some commenters stated that the EPA's analysis of the requirements for ''standard of performance,'' including the BSER, attempted to eliminate the requirement that the standard for emissions must be ''achievable.'' We disagree with this comment. As just quoted, the EPA's analysis recognizes that the standard for emissions must be achievable through the application of the BSER.

[152] *Essex Chem. Corp.* v. *Ruckelshaus,* 486 F.2d 427, 433–34 (D.C. Cir. 1973), *cert. denied,* 416 U.S. 969 (1974).

[153] *Nat'l Lime Ass'n* v. *EPA,* 627 F.2d 416, 433, n.46 (D.C. Cir. 1980).

[154] *Sierra Club* v. *Costle,* 657 F.2d 298, 377 (D.C. Cir. 1981) (citing *Nat'l Lime Ass'n* v. *EPA,* 627 F.2d 416 (D.C. Cir. 1980). In considering the representativeness of the source tested, the EPA may consider such variables as the '''feedstock, operation, size and age' of the source.'' *Nat'l Lime Ass'n* v. *EPA,* 627 F.2d 416, 433 (D.C. Cir. 1980). Moreover, it may be sufficient to ''generalize from a sample of one when one is the only available sample, or when that one is shown to be representative of the regulated industry along relevant parameters.'' *Nat'l Lime Ass'n* v. *EPA,* 627 F.2d 416, 434, n.52 (D.C. Cir. 1980).

[155] See 79 FR 1430, 1465 (January 8, 2014), *Sierra Club* v. *Costle,* 657 F.2d at 346–47.

[156] *Sierra Club* v. *Costle,* 657 F.2d at 346 (''Our interpretation of section 111(a) is that the mandated balancing of cost, energy, and nonair quality health and environmental factors embraces consideration of technological innovation as part of that balance. The statutory factors which the EPA must weigh are broadly defined and include within their ambit subfactors such as technological innovation.'').

[157] *See* 79 FR 1430, 1465 (January 8, 2014) (citing S.Rep. 91–1196 at 16 (1970)) (''Standards of performance should provide an incentive for industries to work toward constant improvement in techniques for preventing and controlling emissions from stationary sources''); S. Rep. 95–127 at 17 (1977) (cited in *Sierra Club* v. *Costle,* 657 F.2d at 346 n. 174) (''The section 111 Standards of Performance . . . sought to assure the use of available technology and to stimulate the development of new technology'').

[158] 79 FR 1465 (citing case law and legislative history).

[159] *Sierra Club* v. *Costle,* 657 F.2d at 319.

[160] *Sierra Club* v. *Costle,* 657 F.2d at 321; see also *New York* v. *Reilly, 969 F. 2d at 1150* (because Congress did not assign the specific weight the Administrator should assign to the statutory elements, ''the Administrator is free to exercise [her] discretion'' in promulgating an NSPS).

[161] *Lignite Energy Council* v. *EPA,* 198 F.3d 930, 933 (D.C. Cir. 1999) (paragraphing revised for convenience). S*ee also NRDC* v. *EPA,* 25 F.3d 1063, 1071 (D.C. Cir. 1994) (The EPA did not err in its final balancing because ''neither RCRA nor EPA's regulations purports to assign any particular weight to the factors listed in subsection (a)(3). That being the case, the Administrator was free to emphasize or deemphasize particular factors, constrained only by the requirements of reasoned agency decision making.'').

[162] 79 FR 1430, 1466 (January 8, 2014).

Commenters contested this assertion, arguing that a 111(b) standard must be achievable by all new sources. We continue to take the same position as at proposal for the reasons described there. We note that as a practical matter, in this rulemaking, the issue of whether all new steam-generating sources can implement partial-capture CCS is largely dependent on the geographic scope of geologic sequestration sites. As discussed below in Section V.M, geologic sequestration sites are widely available, and a steam-generating plant with partial CCS that is sited near an area that is suitable for geologic sequestration can serve demand in a large area that may not have sequestration sites available. In any event, the standard of 1,400 lb CO_2/MW-g that we promulgate in this final rule can be achieved by new steam generating EGUs—including new utility boilers and IGCC units—through co-firing with natural gas in lieu of installing partial CCS, which moots the issue of the geographic availability of geologic sequestration.

g. EPAct05

The Energy Policy Act of 2005 (''EPAct05'') authorizes assistance in the form of grants, loan guarantees, as well as federal tax credits for investment in ''clean coal technology.'' Sections 402(i), 421(a), and 1307(b) (adding section 48A(g) to the Internal Revenue Code (''IRC'')) address the extent to which information from clean coal projects receiving assistance under the EPAct05 may be considered by the EPA in determining what is the best system of emission reduction adequately demonstrated. Section 402(i) of the EPAct05 limits the use of information from facilities that receive assistance under EPAct05 in CAA section 111 rulemakings:

''No technology, or level of emission reduction, solely by reason of the use of the technology, or the achievement of the emission reduction, by 1 or more facilities receiving assistance under this Act, shall be considered to be adequately demonstrated [ ] for purposes of section 111 of the Clean Air Act. . . .'' [163]

IRC section 48A(g) contains a similar constraint concerning the use of technology or level of emission reduction from EGU facilities for which a tax credit is allowed:

''No use of technology (or level of emission reduction solely by reason of the use of the technology), and no achievement of any emission reduction by the demonstration of any technology or performance level, by or at one or more facilities with respect to which a credit is allowed under this section, shall be considered to indicate that the technology or performance level is adequately demonstrated [ ] for purposes of section 111 of the Clean Air Act. . . .''

The EPA specifically solicited comment on its interpretation of these provisions. 79 FR 10750 (Feb. 26, 2014) (Notice of Data Availability). With respect to EPAct05 sections 402(i) and 421(a), the EPA proposed that these provisions barred consideration where EPAct05-assisted facilities were the sole support for the BSER determination, but that these sources could support a BSER determination so long as there is additional evidence supporting the determination.[164] In addition, the EPA viewed the two prohibitions as relating only to the technology or emissions reduction for which assistance was given.[165] The EPA likewise interpreted IRC section 48A(g)—based on the plain language and the context provided by sections 402(i) and 421(a)—to mean that use of technology, or emission performance, from a facility for which the credit is allowed cannot, by itself, support a finding that the technology or performance level is adequately demonstrated, but the information can corroborate an otherwise supported determination or otherwise provide part of the basis for such a determination.[166] The EPA also proposed to interpret the phrase ''with respect to which a credit is allowed under this section'' as referring to the entire phrase ''use of technology (or level of emission reduction . . .) and [] achievement of any emission reduction . . . , by or at one or more facilities.'' Thus, if technology A received a tax credit, but technology B at the same facility did not, the constraint would not apply to technology B.[167]

Some commenters supported the EPA's proposed interpretation. Others contended that the EPA's interpretation would allow it to support a BSER determination even where EPAct05 facility information comprised 99 percent of the supporting information for a BSER determination because that determination would not be based ''solely'' on EPAct05 sources. These commenters urged the EPA to conclude that a determination ''solely'' on the basis of information from EPAct05-assisted facilities is any determination where ''but for'' that information, the EPA could not justify its chosen standard as the BSER.[168] Other commenters argued that the provisions bar the EPA from all consideration of EPAct05 facilities when determining that a technology or level of performance is adequately demonstrated.

In this final rule, the EPA is adopting the interpretations of all three provisions that it proposed, largely for the reasons previously advanced. The EPA thus interprets these provisions to preclude the EPA from relying solely on the experience of facilities that received DOE assistance, but not to preclude the EPA from relying on the experience of such facilities in conjunction with other information. This reading of sections 402(i) and 421(a) is consistent with the views of the only court to date to consider the matter.[169]

The EPA notes that the extreme hypothetical posed in the comments (where the EPA might avoid a limitation on its consideration of EPAct05-assisted facilities by including a mere scintilla of evidence from non-EPAct05 facilities) is not presented here, where the principal evidence that partial post-combustion CCS is a demonstrated and feasible technology comes from sources which received no assistance of any type under EPAct05. The EPA also concludes that the ''but for'' test urged by these commenters is an inappropriate reading of the term ''solely'' in sections 402(i) and 421(a), as any piece of evidence may be a necessary, or ''but for,'' cause without being a sufficient, or ''sole,'' cause.[170] Nonetheless, if the ''but for'' test were applicable here, the available evidence would satisfy it.

[163] Codified at 42 U.S.C. 15962(a). EPAct05 section 421(a) similarly states: ''No technology, or level of emission reduction, shall be treated as adequately demonstrated for purpose [sic] of section 7411 of this title, . . . solely by reason of the use of such technology, or the achievement of such emission reduction, by one or more facilities receiving assistance under section 13572(a)(1) of this title''.

[164] Technical Support Document, *Effect of EPAct05 on Best System of Emission Reduction for New Power Plants,* p. 6 (Docket entry: EPA–HQ–OAR–2013–0495–1873).

[165] Id.

[166] Id. p. 13.

[167] Id. p. 14.

[168] Comments of AFPM/API p. 46 (Docket entry: EPA–HQ–OAR–2013–0495–10098).

[169] *State of Nebraska* v. *EPA,* 2014 U.S. Dist. LEXIS 141898 at n. 1 (D. Nebr. 2014). (''But the Court notes that § 402(i) only forbids the EPA from considering a given technology or level of emission reduction to be adequately demonstrated *solely* on the basis of federally-funded facilities. 42 U.S.C. 15962(i). In other words, such technology might be adequately demonstrated if that determination is based at least in part on non-federally-funded facilities'') (emphasis original).

[170] For example, any vote of a Justice on the Supreme Court may be a necessary but not sufficient cause. In a 5–4 decision, the decision of the Court would have been different ''but for'' the assent of Justice A or Justice B, who were in the majority. But it would be incorrect to say that the assent of Justice A was the ''sole'' reason for the outcome, when the decision also required the assent of Justice B.

Other commenters took the extreme position that the EPAct05 provisions bar all consideration of a facility's existence if the facility received EPAct05 assistance.[171] The EPA does not accept this argument because it is contrary to both the plain statutory language [172] (see Chapter 2 of the Response-to-Comment document) and to Congress's intent that the EPAct05 programs advance the commercialization of clean coal technology. For the same reason, the EPA does not accept some commenters' suggestion that sections 402(i), 421(a), and 48A(g) preclude the EPA from considering NETL's cost projections for CCS, which base cost estimates on up-to-date vendor quotes reflecting costs for the CCS technology being utilized at the Boundary Dam Unit #3 facility (a facility receiving no assistance under EPAct05), but also considers that to-be-built plants will no longer be first-of-a kind. See generally Section V.I.2 below. Commenters suggest that the EPAct05 requires that the EPA treat future plants as ''first of a kind'' when projecting costs, as if EPAct05 facilities simply did not exist. This reading is contrary to the text of the provisions, which as noted, relates specifically to a source's performance and operation (whether a technology is demonstrated, and the level of performance achieved by use of technology), not to sources' existence. NETL's cost projections, on the other hand, merely acknowledge the evident fact that CCS technologies exist, and reasonably project that they will continue to develop. See Section V.I.2. The NETL cost estimates, moreover, are based on vendor quotes for the CCS technology in use at the Boundary Dam facility, a Canadian plant which obviously is not a recipient of EPAct05 assistance. See sections V.D.2.a and V.I.2 below.

In any case, as shown in Section V below, the EPA finds that a new highly-efficient SCPC EGU implementing partial post-combustion CCS is the best system of emission reduction adequately demonstrated and is doing so based in greater part on performance of facilities receiving no assistance under EPAct05, and on other information likewise not having any connection to EPAct05 assistance. The corroborative information from EPAct05 facilities, though supportive, is not necessary to the EPA's findings.

I. Severability

This rule has numerous components, and the EPA intends that they be severable from each other to the extent that they function separately. For example, the EPA intends that each set of BSER determinations and standards of performance in this rulemaking be severable from each other set. That is, the BSER determination and standard of performance for newly constructed fossil fuel-fired electric utility steam generating units are severable from all the other BSER determinations and standards of performance, and the same is true for the BSER determination and standard of performance for modified fossil fuel-fired electric utility steam generating units, and so on. It is reasonable to consider each set of BSER determination and standard of performance to be severable from each other set of BSER determination and standard of performance because each set is independently justifiable and does not depend on any other set. Thus, in the event that a court should strike down any set of BSER determination and standard of performance, the remaining BSER determinations and standards of performance should not be affected.

J. Certain Projects Under Development

In the January 2014 proposal, the EPA indicated that the proposed Wolverine EGU project (Rogers City, Michigan) appeared to be the only fossil fuel-fired steam generating unit that was currently under development that may be capable of ''commencing construction'' for NSPS purposes at the time of the proposal. See 79 FR 1461. The EPA also acknowledged that the Wolverine EGU, as designed, would not meet the proposed standard of 1,100 lb CO_2/MWh for new utility steam generating EGUs. The EPA proposed that, at the time of finalization of the proposed standards, if the Wolverine project remains under development and has not either commenced construction or been canceled, we anticipated proposing a standard of performance specifically for that facility. Additional discussion of the approach can be found in the proposal or in the technical support document in the docket entitled ''Fossil Fuel-Fired Boiler and IGCC EGU Projects under Development: Status and Approach.''

In December 2013—after the proposed action was signed, but before it was published—Wolverine Power Cooperative announced that it was cancelling construction of the proposed coal-fired power plant in Rogers City, MI.[173] Therefore, we are not finalizing the proposed exclusion for that project.

In the January 2014 proposal, the EPA also identified two other fossil fuel-fired steam generating EGU projects that, as currently designed, would not meet the proposed 1,100 lb CO_2/MWh emissions standard—the Plant Washington project in Georgia and the Holcomb 2 project in Kansas. We indicated that, at the time of the proposal, those projects appeared to remain under development but that the project developers had represented that the projects have commenced construction for NSPS purposes and, thus, would not be new sources subject to the proposed or final NSPS. Based solely on the developers' representations, the EPA indicated that those projects, if ultimately fully constructed, would be existing sources, and would thus not be subject to the standards of performance in this final action.

To date, neither developer has sought a formal EPA determination of NSPS applicability. As we specified in the January 2014 proposal—and we reiterate here—if such an applicability determination concludes that either the Plant Washington (GA) project or the Holcomb 2 (KS) project did not commence construction prior to January 8, 2014 (the publication of the January 2014 proposal), then the project should be situated similarly to the disposition the EPA proposed for the Wolverine project. Accordingly, the EPA is finalizing in this action that if it is determined that either of these projects has not commenced construction as January 8, 2014, then that project will be addressed in the same manner as was proposed for the Wolverine project.

In public comments submitted in response to the January 2014, Power4Georgians (P4G), the Plant Washington developer, reiterated that they had executed binding contracts for the purchase and erection of the facility boiler prior to publication of the January 2014 proposal and believe that the binding contracts are sufficient to constitute commencement of construction for purposes of the NSPS program, so that they are existing rather than new sources for purposes of this

[171] Supplemental Comments of Murray Energy p. 11 (Docket entry: EPA–HQ–OAR–2013–0495–9498).

[172] With respect to sections 402(i) and 421(a), commenters fail to reconcile their reading of the statute with the Act's grammatical structure, as explained in detail in chapter 2 of the Response-to-Comment document. One commenter supported its reading by adding suggested text to the statutory language, a highly disfavored form of statutory construction. Comments of UARG, p.124 n.38 (Docket entry: EPA–HQ–OAR–2013–0495–9666). With respect to section 48A(g), commenters misread the phrase ''considered to indicate,'' and do not explain how their reading of all three provisions together is tenable.

[173] ''Wolverine ends plant speculation in Rogers City'', The Alpena News, December 17, 2013. *http://www.thealpenanews.com/page/content.detail/id/527862/Wolverine-ends-plant-speculation-in-Rogers-City.html?nav=5004.*

rule.[174] Public comments submitted by Tri-State Generation and Transmission Association and Sunflower Electric Power Corporation, the developers of the Holcomb 2 project, discussed the cost incurred in the development of the project. They also indicated they had awarded contracts for the turbine/generator purchase and had negotiated a rail-supply agreement that provides for the delivery of fuel to the proposed Holcomb 2 site. The developers did not, however, explicitly characterize the construction status of the project.[175] Other groups submitted comments contending that neither project has actually commenced construction.

In October 2013, the Kansas Supreme Court invalidated the 2010 air pollution permit granted to Sunflower Electric Power Corporation by the Kansas Department of Health and Environment (KDHE).[176] In May 2014, the KDHE issued an air quality permit addendum for the proposed Holcomb 2 coal plant. The addendum addressed federal regulations that the Kansas Supreme Court held had been overlooked in the initial permitting determination. In June 2014, the Sierra Club filed an appeal with the Kansas Appellate Court challenging the legality of the May 2014 permit. Since the publication of the January 2014 proposal, the EPA is unaware of any physical construction activity at the proposed Holcomb 2 site.

In October 2014, the Plant Washington project was given an 18-month air permit extension by the Georgia Environmental Protection Division (EPD). However, as with the Holcomb expansion project, the EPA is unaware of any physical construction that has taken place at the proposed Plant Washington site and a recent audit of the project described it as ''dormant''.[177]

Based on this information, it appears that these sources have not commenced construction for purposes of section 111(b) and therefore would likely be new sources should they actually be constructed. As noted above, the EPA proposed that, if these projects are determined to not have commenced construction for NSPS purposes prior to the publication of the proposed rule, they will be addressed in the same manner proposed for the Wolverine project. 79 FR 1461. We are finalizing that proposal here. However, because these units may never actually be fully built and operated, we are not promulgating a standard of performance at this time because such action may prove to be unnecessary.[178]

There is one possible additional new EGU, the Two Elk project in Wyoming. In a supporting TSD accompanying the January 2014 proposal, we discussed the Two Elk project and relied on developer statements and state acquiescence that the unit had commenced construction for NSPS purposes before January 8, 2014.[179] We did not, therefore, propose any special section 111(b) standard for the project. Some commenters maintained that a continuous program of construction at the facility has not been maintained and that if the plant is ultimately constructed, it should be classified as a new source under CAA section 111(b). These comments were not specific enough to change the EPA's view of the project for purposes of this rulemaking. We accordingly continue to rely on developer statements that this facility has commenced construction and would not be a new source for purposes of this proceeding.

IV. Summary of Final Standards for Newly Constructed, Modified, and Reconstructed Fossil Fuel-Fired Electric Utility Steam Generating Units

This section sets forth the standards for newly constructed, modified, and reconstructed steam generating units (*i.e.,* utility boilers and IGCCs). We explain the rationale for the final standards in Sections V (newly constructed steam generating unit), VI (modified steam generating units), and VII (reconstructed steam generating units).

A. Applicability Requirements and Rationale

We generally refer to fossil fuel-fired electric utility generating units that would be subject to an emission standard in this rulemaking as ''affected'' or ''covered'' sources, units, facilities or simply as EGUs. These units meet both the definition of ''affected'' and ''covered'' EGUs subject to an emission standard as provided by this rule, and the criteria for being considered ''new,'' ''modified'' or ''reconstructed'' sources as defined under the provisions of CAA section 111 and the EPA's regulations. This section discusses applicability for newly constructed, modified, and reconstructed steam generating units.

1. General Applicability Criteria

The EPA is finalizing applicability criteria for new, modified, and reconstructed electric utility steam generating units (*i.e.,* utility boilers and IGCC units) in 40 CFR part 60, subpart TTTT that are similar to the applicability criteria for those units in 40 CFR part 60, subpart Da (utility boiler and IGCC performance standards for criteria pollutants), but with some differences. The proposed applicability criteria, relevant comments, and final applicability criteria specific to newly constructed, modified, and reconstructed steam generating units are discussed below.

The applicability requirements in the proposal for newly constructed EGUs included that a utility boiler or IGCC unit must: (1) Be capable of combusting more than 250 MMBtu/h heat input of fossil fuel; (2) be constructed for the purpose of supplying, and actually supply, more than one-third of its potential net-electric output capacity to any utility power distribution system (that is, to the grid) for sale on an annual basis; (3) be constructed for the purpose of supplying, and actually supply, more than 219,000 MWh net-electric output to the grid on an annual basis; and (4) combust over 10 percent fossil fuel on a heat input basis over a 3-year average. At proposal, applicability was determined based on a combination of design and actual operating conditions that could change annually depending on the proportion and the amount of electricity actually sold and on the proportion of fossil fuels combusted by the unit.

In the proposal for modified and reconstructed EGUs, we proposed a broader applicability approach such that applicability would be based solely on design criteria and would be identical to the applicability requirements in

[174] Docket entry: EPA–HQ–OAR–2013–0495–9403.

[175] Docket entry: EPA–HQ–OAR–2013–0495–9599.

[176] ''Kansas High Court Invalidates 895–MW Coal Project Air Permit'', Power Magazine, 10/10/2013, available at: *www.powermag.com/kansas-high-court-invalidates-2010-895-mw-coal-project-air-permit/.*

[177] *http://www.macon.com/2015/06/23/3811798/audit-sandersville-coal-plant.html.*

[178] In the proposed emission guidelines for existing EGUs, the EPA did not include estimates of emissions for either Plant Washington or the Holcomb 2 unit in baseline data used to calculate proposed state goals for Georgia and Kansas. It appears that the possibility of these plants actually being built and operating is too remote. If either unit eventually seeks an applicability determination and that unit is determined to be an existing source, and there is reliable evidence that the source will operate, then the source will be subject to the final 111(d) rule and the EPA will allow the state to adjust its state goal to reflect adjustment of the state's baseline data so as to include the unit. Guidance for adjustment of state goals is provided in the record for the EPA's final CAA section 111(d) rulemaking.

[179] ''Fossil Fuel-Fired Boiler and IGCC EGU Projects Under Development: Status and Approach'', Technical Support Document at pp. 10–1 (Docket Entry: EPA–HQ–OAR–2013–0495–0024).

subpart Da. First, we proposed electric sales criteria that the source be constructed for the purpose of selling more than one-third of their potential electric output and more than 219,000 MWh to the grid on an annual basis, regardless of the actual amount of electricity sold (*i.e.,* we did not include the applicability criterion that the unit actually sell the specified amount of electricity on an annual basis). In addition, we proposed a base load rating criterion that the source be capable of combusting more than 250 MMBtu/h of fossil fuel, regardless of the actual amount of fossil fuel burned (*i.e.,* we did not include the fossil fuel-use criterion that an EGU actually combust more than 10 percent fossil fuel on a heat input basis on a 3-year average). Under this approach, applicability would be known prior to the unit actually commencing operation and would not change on an annual basis. We also proposed that the final applicability criteria would be consistent for newly constructed, reconstructed, and modified units. The proposed broad applicability criteria would still not have included boilers and IGCC units that were constructed for the purpose of selling one-third or less of their potential output or 219,000 MWh or less to the grid on an annual basis. These units are not covered under subpart Da (the utility boiler and IGCC EGU criteria pollutant NSPS) but are instead covered as industrial boilers under subpart Db (industrial, institutional, and commercial boilers NSPS) or subpart KKKK (the combustion turbine criteria pollutant NSPS).

We solicited comment on whether, to avoid implementation issues related with different interpretations of ''constructed for the purpose,'' the total and percentage electric sales criteria should be recast to be based on permit conditions. The ''constructed for the purpose'' language was included in the original subpart Da rulemaking. At that time, the vast majority of new steam generating units were clearly base load units. The ''constructed for the purpose'' language was intended to exempt industrial CHP units. These units tend to be relatively small and were not the focus of the rulemaking. In addition, units not meeting the electric sales applicability criteria in subpart Da would be covered by other NSPS so there is limited regulatory incentive, or impact to the environment, for owners/operators to avoid applicability with the utility NSPS. However, for new units, there is no corresponding industrial unit CO_2 NSPS and existing units could debate their original intent (*i.e.,* the purpose for which they were constructed) in an attempt to avoid applicability under section 111(d) requirements. Consequently, there could be a regulatory incentive for owners/operators to circumvent the CO_2 NSPS applicability. For units that avoid coverage, there would also be a corresponding environmental impact. For example, an owner/operator of a new unit could initially request a permit restriction to limit electric sales to less than one-third of potential annual electric output, but amend the operating permit shortly after operation has commenced to circumvent the intended applicability. Many existing units were initially built with excess capacity to account for projected load growth and were intended to sell more than one-third of their potential electric output. However, due to various factors (lower than expected load growth, availability of other lower cost units, etc.), certain units might have sold less than one-third of their potential electric output, at least during their initial period of operation. Therefore, the EPA has concluded that determining applicability based on whether a unit is ''*constructed for the purpose of* supplying one-third or more of its potential electric output and more than 219,000 MWh as net-electric sales'' (emphasis added) could create applicability uncertainty for both the regulated community and regulators. In addition, we have concluded that applicability based on actual operating conditions (*i.e.,* actual electric sales) is not ideal because applicability would not be known prior to determining compliance and could change annually.

This action finalizes applicability criteria based on design characteristics and federally enforceable permit restrictions included in each individual permit. Based on restrictions, if any, on annual total electric sales in the operating permit, it will be clear from the time of construction whether or not a new unit is subject to this rule. The applicability includes all utility boilers and IGCC units unless the electric sales restriction was in the original and remains in the current operating permit without any lapses (this is to be consistent with the 'constructed for the purpose of' criteria in subpart Da). We have concluded that this approach is equivalent to, but clearer than, the existing language used in subpart Da. In addition, we have concluded that it is important for both the 111(b) and 111(d) requirements for electric-only steam generating units that the permit restriction limiting annual electric sales be included in both the original and current operating permit. Without this restriction, existing units could avoid obligations under state plans developed as part of the 111(d) program by amending their operating permit to limit total annual electric sales to one-third of potential electric output. These units would not be subject to any GHG NSPS requirements because they would not meet the 111(b) or 111(d) applicability criteria and, at this time, there is no NSPS that would cover these units. As described in Section III, industrial CHP and dedicated non-fossil units also are not affected EGUs under this final action.

In this rule, we are finalizing the definition of a steam generating EGU as a utility boiler or IGCC unit that: (1) Has a base load rating greater than 260 GJ/h (250 MMBtu/h) of fossil fuel (either alone or in combination with any other fuel) and (2) serves a generator capable of supplying more than 25 MW-net to a utility distribution system (*i.e.,* for sale to the grid). However, we are not establishing final CO_2 standards for certain EGUs. These include: (1) Steam generating units and IGCC units that are currently subject to—and have been continuously subject to—a federally enforceable permit limiting annual electric sales to one-third or less of their potential electric output (*e.g.,* limiting hours of operation to less than 2,920 hours annually) or limiting annual electric sales to 219,000 MWh or less; (2) units subject to a federally enforceable permit that limits the use of fossil fuels to 10 percent or less of the unit's heat input capacity on an annual basis; and (3) CHP units that are subject to a federally enforceable permit condition limiting annual total electric sales to no more than their design efficiency times their potential electric output, or to no more than 219,000 MWh, whichever is greater.

2. Applicability Specific to Newly Constructed Steam Generating Units

In CAA section 111(a)(2), a ''new source'' is defined as any stationary source, the construction or modification of which is commenced after the publication of regulations (or if earlier, proposed regulations) prescribing a standard of performance under this section which will be applicable to such source. Accordingly, for purposes of this rule, a newly constructed steam generating EGU is a unit that fits the definition and applicability criteria of a fossil fuel-fired steam generating EGU and commences construction on or after January 8, 2014, which is the date that the proposed standards were published for those sources (see 79 FR 1430).

3. Applicability Specific to Modified Steam Generating Units

In CAA section 111(a)(4), a ''modification'' is defined as ''any physical change in, or change in the method of operation of, a stationary source'' that either ''increases the amount of any air pollutant emitted by such source or . . . results in the emission of any air pollutant not previously emitted.'' The EPA, through regulations, has determined that certain types of changes are exempt from consideration as a modification.[180]

For purposes of this rule, a modified steam generating EGU is a unit that fits the definition and applicability criteria of a fossil fuel-fired steam generating EGU and that modifies on or after June 18, 2014, which is the date that the proposed standards were published for those sources (see 79 FR 34960).

4. Applicability Specific to Reconstructed Steam Generating Units

The NSPS general provisions (40 CFR part 60, subpart A) provide that an existing source is considered a new source if it undertakes a ''reconstruction,'' which is the replacement of components of an existing facility to an extent that: (1) The fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility, and (2) it is technologically and economically feasible to meet the applicable standards.[181]

For purposes of this rule, a reconstructed steam generating EGU is a unit that fits the definition and applicability criteria of a fossil fuel-fired steam generating EGU and that reconstructs on or after June 18, 2014, which is the date that the proposed standards were published for those sources (see 79 FR 34960).

B. Best System of Emission Reduction

1. BSER for Newly Constructed Steam Generating Units

In the January 2014 proposal, the EPA proposed that highly efficient new generation technology implementing partial CCS is the BSER for GHG emissions from new steam generating EGUs. (See generally 79 FR 1468–1469.) In this final action, the EPA has determined that the BSER for newly constructed steam generating units is a new highly efficient supercritical pulverized coal (SCPC) boiler implementing partial CCS technology to the extent of removal efficiency that meets a final emission limitation of 1,400 lb CO_2/MWh-g. The final standard of performance is less stringent than the proposed emission limitation of 1,100 lb CO_2/MWh-g. This change, as will be discussed in greater detail later in this preamble, is in response to public comments and reflects both a re-examination of the potential BSER technologies and the most recent, reliable information regarding technology costs. A newly constructed fossil fuel-fired supercritical utility boiler will be able to meet the final standard by implementing post-combustion carbon capture treating a slip-stream of the combustion flue gas. Alternative potential compliance paths are to build a new IGCC unit and co-fire with natural gas (or use pre-combustion carbon capture on a slip-stream), or for a supercritical utility boiler to co-fire with natural gas.

The EPA of course realizes that the final standard of performance (1,400 lb CO_2/MWh-g) differs from the proposed standard (1,100 lb CO_2/MWh-g). The EPA notes further, however, that the methodology for determining the final standard of performance is identical to that at proposal—determining that a new highly efficient generating technology implementing some degree of partial CCS is the BSER, with that degree of implementation being determined based on the reasonableness of costs. A key means of assessing the reasonableness of cost at proposal was comparison of the levelized cost of electricity (LCOE) with that of other dispatchable, base load non-NGCC generating options. We have maintained that approach in identifying BSER for the final standard. Applying this methodology to the most recent cost information has led the EPA to adopt the final standard of performance of 1,400 lb CO_2/MWh-g. See Section V.H at Table 8 below. This final standard reflects the level of emission reduction achievable by a highly efficient SCPC implementing the degree of partial CCS that remains cost comparable to the other non-NGCC dispatchable base load generating options.

The BSER for newly constructed steam generating EGUs in the final rule is very similar to that in the proposal. In this final action, the EPA finds that a highly efficient new SCPC EGU implementing partial CCS to the degree necessary to achieve an emission of 1,400 lb CO_2/MWh-g is the BSER. Contrary to the January 2014 proposal, the EPA finds that IGCC technology—either alone or implementing partial CCS—is not part of the BSER, but rather is a viable alternative compliance option. As noted at proposal, a BSER typically advances performance of a technology beyond current levels of performance. 79 FR 1465, 1471. Similarly, promotion of technology innovation can be a relevant factor in BSER determinations. Id. and Section III.H.3.d above. For these reasons, the EPA at proposal voiced concerns about adopting standards that would allow an IGCC to comply without utilizing CCS for slip-stream control. Id. at 1471. The final standard of 1,400 lb CO_2/MWh-g, adopted as a means of assuring reasonableness of costs, allows IGCC units to comply without using partial CCS. Thus, although the standard can be met by a highly efficient new IGCC unit using approximately 3 percent partial CCS (see Sections V.E and V.H.7 below), the EPA does not believe that implementation of partial CCS at such a low level, while technically feasible, is the option that utilities and project developers will choose. The EPA believes that IGCC project developers will either choose to meet the final standard by co-firing with natural gas—which would be a less costly and very straightforward process for a new IGCC unit—or they will choose to install CCS equipment that will allow the facility to achieve much deeper CO_2 reductions than required by this rule—likely to co-produce chemicals and/or to capture large volumes of CO_2 for use in EOR operations. Similarly, project developers may also—as an alternative to utilizing partial CCS technology—meet the final standard by co-firing approximately 40 percent natural gas in a new highly efficient SCPC EGU.

While the EPA does not find that IGCC technology—either alone or with implementation of partial CCS—is part of the BSER for new steam generating EGUs, we remain convinced that it is technically feasible (see Section V.E below) and believe that it represents a viable alternative compliance option that some project developers will consider to meet the final standard issued in this action. The EPA notes further that IGCC is available at reasonable cost (see Table 9 below), and involves use of an advanced technology. So, although the final standard reflects performance of a BSER which includes partial CCS, even in the instances that a compliance alternative might be utilized, that alternative would both result in emission reductions consistent with use of the BSER, and would reflect many of the underlying principles and attributes of the BSER (costs are both reasonable, not greatly dissimilar than BSER, no collateral adverse impacts on health or the environment, and reflects

[180] 40 CFR 60.2, 60.14(e).

[181] 40 CFR 60.15.

performance of an advanced technology).

In reaching the final standard of performance, the EPA is aware that at proposal, the agency stated that it was not ''currently considering'' a standard of performance as high as 1,400 lb CO_2/MWh-g. 79 FR 1471. However, in that same discussion, the EPA noted the reasons for its reservations (chiefly reservations about the extent of emission reductions, promotion of advanced CO_2 control technologies, and whether the standard could be met by either utility boilers or IGCC units co-firing with natural gas, or otherwise complying without utilizing partial CCS), and we specifically solicited comment on the issue: ''We request that commenters who suggest emission rates above 1,200 lb CO_2/MWh address potential concerns about providing adequate reductions and technology development to be considered BSER.'' Id. The proposal thus both solicited comment on higher emission standards (including 1,400 lb CO_2/MWh-g based on a less aggressive rate of partial CCS), and provided ample notice of the methodology the EPA would use to determine the final BSER and the corresponding final standard.[182] For these reasons, the EPA believes that it provided adequate notice of this potential outcome at proposal, that the final standard of performance was reasonably foreseeable, and that the final standard is a logical outgrowth of the proposed rule. *Allina Health Services* v. *Sebelius,* 746 F. 3d 1102, 1107 (D.C. Cir. 2014).

A more detailed discussion of the rationale for the final BSER determination and of other systems that were also considered is provided in Section V.P of this preamble.[183]

2. BSER for Modified Steam Generating Units

The EPA has determined that, as proposed, the BSER for steam generating units that trigger the modification provisions is the modified unit's own best potential performance. However, as explained below, the final BSER determination and the scope of modifications to which the final standards apply differ in some important respects from what the EPA proposed.

The EPA proposed that the modified unit's best potential performance would be determined depending upon when the unit implemented the modification (*i.e.,* before or after being subject to an approved CAA section 111(d) state plan). For units that commenced modification prior to becoming subject to an approved CAA section 111(d) state plan, the EPA proposed unit-specific standards consistent with each modified unit's best one-year historical performance (during the years from 2002 to the time of the modification) plus an additional two percent reduction. For sources that commenced modification after becoming subject to an approved CAA section 111(d) plan, the EPA proposed that the unit's best potential performance would be determined from the results of an efficiency audit.

The final standards in this action do not depend upon when the modification commences, as long as it commences after June 18, 2014. We are establishing emission standards for large modifications in this rule and deferring at this time the setting of standards for small modifications.

In this final action, the EPA is issuing final emission standards for affected steam generating units that implement larger modifications that are consistent with the proposed BSER determination for those units. The final standard for those sources that implement larger modifications is a unit-specific emission limitation consistent with each modified unit's best one-year historical performance (during the years from 2002 to the time of the modification), but does not include the additional two percent reduction that was proposed in the January 2014 proposal.

In this action, the EPA is not finalizing standards for those sources that conduct smaller modifications and is withdrawing the proposed standards for those sources. See Section XV below.

A more detailed discussion of the rationale for the BSER determination and final standards is provided in Section VI of this preamble.

3. BSER for Reconstructed Steam Generating Units

Consistent with our proposal, the EPA has determined that the BSER for reconstructed steam generating units is the most efficient demonstrated generating technology for these types of units (*i.e.,* meeting a standard of performance consistent with a reconstructed boiler using the most efficient steam conditions available, even if the boiler was not originally designed to do so). A more detailed discussion of the rationale for the BSER determination and the final standards is provided in Section VII of this preamble.

C. Final Standards of Performance

The EPA is issuing final standards of performance for newly constructed, modified, and reconstructed affected steam generating units based on the degree of emission reduction achievable by application of the best system of emission reduction for those categories, as described above. The final standards are presented below in Table 6.

TABLE 6—FINAL STANDARDS OF PERFORMANCE FOR NEW, MODIFIED, AND RECONSTRUCTED STEAM GENERATING UNITS

Source	Description	Final standard * lb CO_2/MWh-g
New Sources	All newly constructed steam generating EGUs	1,400.

[182] Although co-firing with natural gas is not part of BSER, as noted above, it could be part of a compliance pathway for either SCPC or IGCC units. In this regard, a number of commenters addressed the issue of natural gas co-firing, indicating that there were circumstances where it could be part of BSER. See *e.g.* Comments of Exelon Corp. p. 12 (Docket entry: EPA–HQ–OAR–2013–0495–9406); Comments of the Sierra Club p. 108 Docket entry: EPA–HQ–OAR–2013–0495–9514). See *Northeast Md. Waste Disposal Authority* v. *EPA,* 358 F.3d 936, 952 (D.C. Cir. 2004); *Appalachian Power* v. *EPA,* 135 F.3d 791, 816 (D.C. Cir. 1998) (commenters understood a matter was under consideration when they addressed it in comments).

[183] Certain commenters maintained that the BSER determination does not comply with (purportedly) binding legal requirements created by regulations implementing the Information Quality Act. These comments are mistaken as a matter of both law and fact. The Information Quality Act does not create legal rights in third parties (see, *e.g. Mississippi Comm'n on Environmental Quality* v. *EPA,* no. 12–1309 at 84 (D.C. Cir. June 2, 2015)), and the OMB Guidelines are not binding rules but rather, as their title indicates, guidance to assist agencies. See *State of Mississippi,* 744 F.3d at 1347 (the Guidelines provide ''policy and procedural guidance'', are meant to be ''flexible'' and are to be implemented differently by different agencies accounting for circumstances). There are also significant factual omissions and mischaracterizations in these comments regarding peer review of the proposed standard and underlying record information. The complete response to these comments is in chapter 2 of the RTC. See also Section V.I.2.a and N below describing findings of the SAB panel that materials of the National Energy Technology Laboratory had been fully and adequately peer reviewed, and that the EPA findings related to sequestration of captured CO_2 reflected the best available science.

TABLE 6—FINAL STANDARDS OF PERFORMANCE FOR NEW, MODIFIED, AND RECONSTRUCTED STEAM GENERATING UNITS—Continued

Source	Description	Final standard * lb CO_2/MWh-g
Modified Sources	Sources that implement larger modifications—those resulting in an increase in hourly CO_2 emissions (lb CO_2/hr) of more than 10 percent.	Best annual performance (lb CO_2/MWh-g) during the time period from 2002 to the time of the modification.
Reconstructed Sources	Large **	1,800.
Reconstructed Sources	Small **	2,000.

* Standards are to be met over a 12-operating-month compliance period.
** Large units are those with heat input capacity of >2,000 mmBtu/hr; small units are those with heat input capacity of ≤2,000 mmBtu/hr.

For newly constructed and reconstructed steam generating units and for modified steam generating sources that result in larger hourly increases of CO_2 emissions, the EPA is finalizing standards in the form of a gross energy output-based CO_2 emission limit expressed in units of mass per useful energy output, specifically, in pounds of CO_2 per megawatt-hour (lb CO_2/MWh-g).[184] The standard of performance will apply to affected EGUs upon the effective date of the final action.

Compliance with the final standard will be demonstrated by summing the emissions (in pounds of CO_2) for all operating hours in the 12-operating-month compliance period and then dividing that value by the sum of the useful energy output (on a gross basis, *i.e.,* gross megawatt-hours) over the rolling 12-operating-month compliance period. The final rule requires rounding of emission rates with numerical values greater than or equal to 1,000 to three significant figures and rounding of rates with numerical values less than 1,000 to two significant figures.

For newly constructed steam generating units, we proposed two options for the compliance period. We proposed that a newly constructed source could choose to comply with a 12-operating-month standard or with a more stringent standard over an 84-operating-month compliance period, and we solicited comment on including an interim 12-operating-month standard (based on use of supercritical boiler technology, see 79 FR at 1448). We are not finalizing the proposed 84-operating-month compliance period option because the final standard of performance for newly constructed sources is less stringent than the proposed standard and because, as discussed in Section V below, we are identifying alternative compliance pathways for new steam generating EGUs. Specifically, we have concluded that there are unlikely to be significant issues with short-term variability during initial operation, in view of both the reduced numerical stringency of the standard, and the availability of compliance alternatives. The EPA notes that co-firing of natural gas can also serve as an interim means to reduce emissions if a new source operator believes additional time is needed to phase-in the operation of a CCS system. Therefore, the applicable final standards of performance for all newly constructed, modified, and reconstructed steam generating units must be met over a rolling 12-operating-month compliance period.

In the Clean Power Plan, which is a separate rulemaking under CAA section 111(d) published at the same time as the present rulemaking under CAA section 111(b), the EPA is promulgating emission guidelines for states to develop state plans regulating CO_2 emissions from existing fossil fuel-fired EGUs. Existing sources that are subject to state plans under CAA section 111(d) may undertake modifications or reconstructions and thereby become subject to the requirements under section 111(b) in the present rulemaking. In the section 111(d) Clean Power Plan rulemaking, the EPA discusses how undertaking a modification or reconstruction affects an existing source's section 111(d) requirements.

V. Rationale for Final Standards for Newly Constructed Fossil Fuel-Fired Electric Utility Steam Generating Units

In the discussion below, the EPA describes the rationale and justification of the BSER determination and the resulting final standards of performance for newly constructed steam generating units. We also explain why this determination is consistent with the constraints imposed by the EPAct05.

A. Factors Considered in Determining the BSER

In evaluating the final determination of the BSER for newly constructed steam generating units, the EPA considered the factors for the BSER described above, looked widely at all relevant information and considered all the data, information, and comments that were submitted during the public comment period. We re-examined and updated the information that was available to us and concluded, as described below, that the final standard of 1,400 lb CO_2/MWh-g is consistent with the degree of emission reduction achievable through the implementation of the BSER. This final standard of performance for newly constructed fossil fuel-fired steam generating units provides a clear and achievable path forward for the construction of new coal-fired generating sources that addresses GHG emissions.

B. Highly Efficient SCPC EGU Implementing Partial CCS as the BSER for Newly Constructed Steam Generating Units

In the sections that follow, we explain the technical configurations that may be used to implement BSER to meet the final standard, describe the operational flexibilities that partial CCS offers, and then provide the rationale for the final standard of performance. After that, we discuss, in greater detail, consideration of the criteria for the determination of the BSER. We describe why a highly efficient new SCPC EGU implementing partial CCS in the amount that results in an emission limitation of 1,400 lb CO_2/MWh-g best meets those criteria, including, among others, that such a system is technically feasible, provides meaningful emission reductions, can be implemented at a reasonable cost, does not pose non-air quality health and environmental concerns or impair energy reliability, and consequently is adequately demonstrated. We also explain why the emission standard of 1,400 lb CO_2/MWh-g is achievable, including under all circumstances

[184] Note that the standards for sources that conduct larger modifications is a unit-specific numerical standard based on the unit's best one-year historical performance during the period from 2002 to the time of the modification. The unit-specific standard will also be in the form of a gross energy output-based CO_2 emission limit expressed in pounds of CO_2 per megawatt-hour (lb CO_2/MWh-g).

reasonably likely to occur when the system is properly designed and operated. We also discuss alternative compliance options that new source project developers can elect to use, instead of SCPC with partial CCS, to meet the final standard of performance.

C. Rationale for the Final Emission Standards

1. The Proposed Standards

In the January 2014 proposal, the EPA proposed an emission limitation of 1,100 lb CO_2/MWh-g, which a new highly efficient utility boiler burning bituminous coal could have met by capturing roughly 40 percent of its CO_2 emissions and a new highly efficient IGCC unit could have met by capturing and storing roughly 25 percent of its CO_2 emissions. The captured CO_2 would then be securely stored in sequestration repositories subject to either Class II or Class VI standards under the Underground Injection Control program. The EPA arrived at the proposed standard by examining the available CCS implementation configurations and concluding that the proposed standard at the corresponding levels of partial CCS best balanced the BSER criteria and resulted in an achievable emission level. The EPA also proposed to find that highly efficient new generation implementing ''full CCS'' (*i.e.,* more than 90 percent capture and storage) was not the BSER because the costs of that configuration—for both utility boilers and IGCC units—are projected to substantially exceed the projected costs of other non-NGCC dispatchable technologies that utilities and project developers are considering (*e.g.,* new nuclear and biomass). See generally 79 FR at 1477–78. Conversely, the EPA rejected highly efficient SCPC as the BSER because it would not result in meaningful emission reductions from any newly constructed PC unit. Id. at 1470. The EPA also declined to base the BSER on IGCC operating alone due to the same concern—lack of emission reductions from a new IGCC unit otherwise planned. Id.

2. Basis for the Final Standards

For this final action, the EPA reexamined the BSER options available at proposal. Those options are: (1) Highly efficient generation without CCS, (2) highly efficient generation implementing partial CCS, and (3) highly efficient generation implementing full CCS. Consistent with our determination in the January 2014 proposal, we remain convinced that highly efficient generation (*i.e.,* a new supercritical utility boiler or a new IGCC unit) without CCS does not represent the BSER because it does not achieve emission reductions beyond the sector's business as usual, when options that do achieve more emission reductions are available. 79 FR 1470; see also Section V.P below. We also do not find that a highly efficient new steam generating unit implementing full CCS is the BSER because, at this time, the costs are predicted to be significantly more than the costs for implementation of partial CCS and significantly more than the costs for competing non-NGCC base load, dispatchable technologies—primarily new nuclear generation—and are, therefore, potentially unreasonable. See Section V.P.

As with the proposal, the EPA has determined the final BSER and corresponding emission limitation by appropriately balancing the BSER criteria and determining that the emission limitation is achievable. The final standard of performance of 1,400 lb CO_2/MWh-g is less stringent than at proposal and reflects changes that are responsive to comments received on, and the EPA's further evaluation of, the costs to implement partial CCS. The EPA has determined that a newly constructed highly efficient supercritical utility boiler burning bituminous coal can meet this final emission limitation by capturing 16 percent of the CO_2 produced from the facility (or 23 percent if burning subbituminous or dried lignite), which would be either stored in on-site or off-site geologic sequestration repositories subject to control under either the Class VI (for geologic sequestration) or Class II (for Enhanced Oil Recovery) standards under the UIC program. This BSER is technically feasible, as shown by the fact that post-combustion CCS technology—both the capture and storage components—is demonstrated in full-scale operation within the electricity generating industry. There are also numerous operating results from smaller-scale projects that are reasonably predictive of operation at full-scale. It is available at reasonable cost, does not have collateral adverse non-air quality health or environmental impacts, and does not have adverse energy implications.

The proposed BSER was a highly efficient newly constructed steam generating EGU implementing partial CCS to an emission standard of 1,100 lb CO_2/MWh-g. The final BSER is a highly efficient SCPC EGU implementing partial CCS to achieve an emission standard of 1,400 lb CO_2/MWh-g. In both cases, the EPA specified that the BSER includes a ''highly efficient'' new EGU implementing partial CCS. This assumes that a new project developer will construct the most efficient generating technology available—*i.e.,* a supercritical or ultra-supercritical utility boiler—that will inherently generate lower volumes of uncontrolled CO_2 per MWh. See Section V.J below. A well performing and highly efficient new SCPC EGU will need to implement lower levels of partial CCS in order to meet the final standard of 1,400 lb CO_2/MWh-g than a less efficient new steam generating EGU. The construction of highly efficient steam generating EGUs—as opposed to less efficient units such as a subcritical utility boiler—will result in lower overall costs from decreased fuel consumption and the need for lower levels of required partial CCS to meet the final standard.

3. Consideration of Projects Receiving Funding Under the EPAct05

As noted in Section III.H.3.g above, the EPA's determination of the BSER here includes review of recently constructed facilities and those planned or under construction to evaluate the control technologies being used and considered. Some of the projects discussed in the January 2014 proposal, and discussed here in this preamble, received or are receiving financial assistance under the EPAct05 (P.L. 109–58). This assistance may include financial assistance from the Department of Energy (DOE), as well as receipt of the federal tax credit for investment in clean coal technology under IRC Section 48A.

As noted above, the EPA interprets these provisions as allowing consideration of EPAct05 facilities provided that such information is not the sole basis for the BSER determination, and particularly so in circumstances like those here, where the information is corroborative but the essential information justifying the determinations comes from facilities and other sources of information with no nexus with EPAct05 assistance. In the discussion below, the EPA explains its reliance on other information in making the BSER determination for new fossil fuel-fired steam generating units. The EPA notes that information from facilities that did not receive any DOE assistance, and did not receive the federal tax credit, is sufficient by itself to support its BSER determination.

D. Post-Combustion Carbon Capture

In this section, we describe a variety of facts that support our conclusion that the technical feasibility of post-combustion carbon capture is adequately demonstrated. First, we describe the technology of post-combustion capture. We then describe EGUs that have previously utilized or are currently utilizing post-combustion carbon capture technology. This discussion is complemented by later sections that explain and justify our conclusions that the technical feasibility of other aspects of partial CCS are adequately demonstrated—namely, the transportation and carbon storage (see Sections V.M. and N). Further, the conclusions of this section are reinforced by the discussion in Section V.F. below, in which we identify commercial vendors that offer carbon capture technology and offer performance guarantees, and discuss industry and technology developers' public pronouncements of their confidence in the feasibility and availability of CCS technologies.

1. Post-Combustion Carbon Capture—How it Works

Post-combustion capture processes remove CO_2 from the exhaust gas of a combustion system—such as a utility boiler. It is referred to as ''post-combustion capture'' because the CO_2 is the product of the combustion of the primary fuel and the capture takes place after the combustion of that fuel. The exhaust gases from most combustion processes are at atmospheric pressure and are moved through the flue gas system by fans. The concentration of CO_2 in most combustion flue gas streams is somewhat dilute.[185] Most post-combustion capture systems utilize liquid solvents [186] that separate the CO_2 from the flue gas in CO_2 scrubber systems. Because the flue gas is at atmospheric pressure and is somewhat dilute, the solvents used for post-combustion capture are ones that separate the CO_2 using chemical absorption (or chemisorption). Amine-based solvents [187] are the most commonly used in post-combustion capture systems. In a chemisorption-based separation process, the flue gas is processed through the CO_2 scrubber and the CO_2 is absorbed by the liquid solvent and then released by heating to form a high purity CO_2 stream. This heating step is referred to as ''solvent regeneration'' and is responsible for much of the ''energy penalty'' of the capture system. Steam from the boiler (or potentially from another external source) that would otherwise be used to generate electricity is instead used in the solvent regeneration process. The development of advanced solvents—those that are chemically stable, have high CO_2 absorption capacities, and have low regeneration energy requirements—is an active area of research. Many post-combustion solvents will also selectively remove other acidic gases such as SO_2 and hydrochloric acid (HCl), which can result in degradation of the solvent. For that reason, the CO_2 scrubber systems are normally installed downstream of other pollutant control devices (*e.g.,* particulate matter and flue gas desulfurization controls) and in some cases, the acidic gases will need to be scrubbed to very low levels prior to the flue gas entering the CO_2 capture system. See also RIA chapter 5 (quantifying SO_2 reductions resulting from this scrubbing process).

Additional information on post-combustion carbon capture—including process diagrams—can be found in a summary technical support document.[188]

2. Post-Combustion Carbon Capture Projects That Have Not Received DOE Assistance Through the EPAct05 or Tax Credits Under IRC Section 48A

a. Boundary Dam Unit #3

SaskPower's Boundary Dam CCS Project in Estevan, a city in Saskatchewan, Canada, is the world's first commercial-scale fully integrated post-combustion CCS project at a coal-fired power plant. The project fully integrates the rebuilt 110 MW coal-fired Unit #3 with a CO_2 capture system using Shell Cansolv amine-based solvent to capture 90 percent of its CO_2 emissions. The facility, which utilizes local Saskatchewan lignite, began operations in October 2014 and accounts of the system's performance describe it as working even ''better than expected.'' [189] [190] The plant started by capturing roughly 75 percent of CO_2 from the plant emissions and its operators plan to increase the capture percentage as they optimize the equipment to reach full capacity. Initial indications are that the facility is producing more power than predicted and that the energy penalty (parasitic load—the energy needed to regenerate the CO_2 capture solvent) is much lower than initially predicted.[191] Water use at the facility is consistent with levels that were predicted.[192] The total project costs—for the power plant and the carbon capture plant—was $1.467B (CAD).[193] The CO_2 from the capture system is more than 99.999 percent pure with only trace levels of N_2 in the product stream.[194] This purity is food-grade quality CO_2 and is a clear indication that the system is working well. The captured CO_2 is transported by pipeline to nearby oil fields in southern Saskatchewan where it is being used for EOR operations. Any captured CO_2 that is not used for EOR operations will be stored in nearby deep brine-filled sandstone formations. Thus, the Boundary Dam Unit #3 project is demonstrating CO_2 post-combustion capture, CO_2 compression and transport, and CO_2 injection for both EOR and geologic storage. The CCS system is fully integrated with the electricity production of the plant.

Some commenters noted that, at 110 MW, the Boundary Dam Unit #3 is a relatively small coal-fired utility boiler and thus, in the commenters' view, does not demonstrate that such a system could be utilized at a much larger utility coal-fired boiler. However, there is nothing to indicate that the post-combustion system used at Boundary Dam could not be scaled-up for use at a larger utility boiler. In fact, the carbon capture system at Boundary Dam #3 is designed and constructed to implement ''full CCS''—that is to capture more than 90 percent of the CO_2 produced from the subcritical unit. A similarly-sized capture system—with no need for further scale-up—could be used to treat a slip-stream of a much larger

[185] The typical concentration of CO_2 in the flue gas of a coal-fired utility boiler is roughly around 15 volume percent.

[186] A *solvent* is a substance (usually a liquid) that dissolves a *solute* (a chemically different liquid, solid or gas), resulting in a solution.

[187] Amines are derivatives of ammonia (NH_3) where one or more hydrogen atoms have been replaced by hydrocarbon groups.

[188] Technical Support Document—''Literature Survey of Carbon Capture Technology'', available in the rulemaking docket (Docket ID: EPA–HQ–OAR–2013–0495).

[189] ''[W]e are achieving better than expected'' operation out of the plant, SaskPower's Mike Marsh said April 8, 2015 in Washington, DC, summarizing the status of the first-of-a-kind plant in Saskatchewan, Canada, known as Boundary Dam Unit 3. Marsh spoke at a meeting of the National Coal Council, which advises the Energy Department on coal-related topics. From ''Bolstering EPA's NSPS, Canadian CCS Plant Working 'Better Than Expected' '', Climate Daily News, Inside EPA/climate (April 08, 2015); *www.insideepa.com* (subscription required).

[190] ''CCS performance data exceeding expectations at world-first Boundary Dam Power Station Unit #3'', *http://www.saskpowerccs.com/newsandmedia/latest-news/ccs-performance-data-exceeding-expectations/.*

[191] Correspondence between Mike Monea (SaskPower) and Nick Hutson (EPA), February 20, 2015.

[192] 30 percent of the water used for cooling comes from the recycled or reclaimed water from the process itself; namely, water in the coal is reclaimed.

[193] About $1.2B USD; roughly $700M (USD) for the carbon capture system, which was on budget.

[194] ''Boundary Dam—The Future is Here'', plenary presentation by Mike Monea at the 12th International Conference on Greenhouse Gas Technologies (GHGT–12), Austin, TX (October 2014).

supercritical utility boiler (a new unit of approximately 500 to 600 MW) in order to meet the final standard of performance of 1,400 lb CO_2/MWh-g, which would only require partial CCS on the order of approximately 16 to 23 percent (depending on the coal used).

A ''slip-stream'' is a portion of the flue gas stream that can be treated separately from the bulk exhaust gas. It is not an uncommon configuration for the flue gas from a coal-fired boiler to be separated into two or more streams and treated separately in different control equipment before being recombined to exit from a common stack.[195] A slip-stream configuration is often used to treat a smaller portion of the bulk flue gas stream as a way of testing or demonstrating a control device or measurement technology. For implementation of post-combustion partial carbon capture, a portion of the bulk flue gas stream would be treated separately to capture approximately 90 percent of the CO_2 from that smaller slip-stream of the flue gas. For example, in order to capture 20 percent of the CO_2 produced by a coal-fired utility boiler, an operator would treat approximately 25 percent of the bulk flue gas stream (rather than treating the entire stream). Approximately 90 percent of the CO_2 would be captured from the slip-stream gas, resulting in an overall capture of about 20 percent.

In its study on the cost and performance of a range of carbon capture rates, the DOE/NETL determined that the slip-stream approach was the most economical for carbon capture of less than 90 percent of the total CO_2.[196] The advantage of the slip-stream approach is that the capture system will be sized to treat a lower volume of flue gas flow, which reduces the size of the CO_2 absorption columns, induced draft fans, and other equipment, leading to lower capital and operating costs.

The carbon capture system at Boundary Dam does not utilize the slip-stream configuration because it was designed to achieve more than 90 percent capture rates from the 110 MW facility. However, the same carbon capture equipment could be used to treat approximately 50 percent of the flue gas from a 220 MW facility—or 20 percent of the flue gas from a 550 MW facility. Thus, the equipment that is currently working very well (in fact, ''better than expected'') at the Boundary Dam plant can be utilized for partial carbon capture at a much larger coal-fired unit without the need for further scale-up.

The experience at Boundary Dam is directly transferrable to other types of post-combustion sources, including those using different boiler types and those burning different coal types. There is nothing to suggest that the Shell CanSolv process would not work with other coal types and indeed, the latest NETL cost estimates assume that the capture technology would be used in a new unit using bituminous coal.[197] The EPA is unaware of any reasons why the Boundary Dam technology would not be transferrable to another utility boiler at a different location at a different elevation or climate because the control technology is not climate or elevation-dependent.

Commenters also noted that the Boundary Dam Unit #3 project received financial assistance from both the Canadian federal government and from the Saskatchewan provincial government. But the availability of—or the lack of—external financial assistance does not affect the technical feasibility of the technology. Commenters further characterized Boundary Dam as a ''demonstration project''. These descriptors are beside the point. Regardless of what the project is called or how it was financed, the project clearly shows the technical feasibility of full-scale, fully integrated implementation of available post-combustion CCS technology, which in this case also appears to be commercially viable.

The EPA notes that, although there is ample additional information corroborating that post-combustion CCS is technically feasible, which we describe below, the performance at Boundary Dam Unit #3 alone would be sufficient to support that conclusion. *Essex Chemical Corp.,* 486 F. 2d at 436 (test results from single facility demonstrates achievability of standard of performance). As mentioned above, the post-combustion capture technology used at Boundary Dam is transferrable to all other types of utility boilers.

b. AES Warrior Run and Shady Point

AES's coal-fired Warrior Run (Cumberland, MD) and Shady Point (Panama, OK) plants are both circulating fluidized bed (CFB) coal-fired power plants with carbon capture amine scrubbers developed by ABB/Lummus. The scrubbers were designed to process a slip-stream of each plant's flue gas. At the 180 MW Warrior Run Plant, a plant that burns bituminous coal, approximately 10 percent of the plant's CO_2 emissions (about 110,000 metric tons of CO_2 per year) has been captured since 2000 and sold to the food and beverage industry. At the 320 MW Shady Point Plant, a plant that burns a blend of bituminous and subbituminous coals, CO_2 from an approximate 5 percent slip-stream (about 66,000 metric tons of CO_2 per year) has been captured since 2001. The captured CO_2 from the Shady Point Plant is also sold for use in the food processing industry.[198] While these projects do not demonstrate the CO_2 storage component of CCS, they clearly demonstrate the technical viability of partial CO_2 capture. The capture of CO_2 from a slip-stream of the bulk flue gas, as described earlier, is the most economical method for capturing less than 90 percent of the CO_2. The amounts of partial capture that these sources have demonstrated—up to 10 percent—is reasonably similar to the level, at 16 to 23 percent, that the EPA predicts would be needed by a new highly efficient steam utility boiler to meet the final standard of performance. These facilities, which have been operating for multiple years, clearly show the technical feasibility of post-combustion carbon capture.

c. Searles Valley Minerals

Since 1978, the Searles Valley Minerals soda ash plant in Trona, CA has used post-combustion amine scrubbing to capture approximately 270,000 metric tons of CO_2 per year from the flue gas of a coal-fired power plant that generates steam and power for on-site use. The captured CO_2 is used for the carbonation of brine in the process of producing soda ash.[199] Again, while the captured CO_2 is not

[195] See Figure 1A from *Atmospheric Environment,* 43, 3974 (2009), for an example of this type of configuration.

[196] ''Cost and Performance of PC and IGCC for a Range of Carbon Capture'', Rev 1 (2013), DOE/NETL–2011/1498 p. 2 (''A literature search was conducted to verify that <90 percent CO_2 capture is most economical using a 'slip-stream' (or bypass) approach. Indeed, the slip-stream approach is more cost-effective for <90 percent CO_2 capture than removing reduced CO_2 fractions from the entire flue gas stream, according to multiple peer-reviewed studies.'' See also id. at 19, 21, 77, and 478 (documenting further that treating a slip-stream is the most economical approach).

[197] In fact, in ''Cost and Performance Baseline for Fossil Energy Plants Volume 1a: Bituminous Coal (PC) and Natural Gas to Electricity Revision 3'', DOE/NETL–2015/1723 (July 2015), Exh.2–3 the Shell Cansolv process is used as the capture process for a new SCPC unit using bituminous coal rather than the subcritical PC unit at Boundary Dam that uses Canadian lignite. The study evidently assumes that the CanSolv process can be used effectively for bituminous coal since this type of coal is assumed for cost estimation purposes.

[198] Dooley, J. J., et al. (2009). ''An Assessment of the Commercial Availability of Carbon Dioxide Capture and Storage Technologies as of June 2009''. U.S. DOE, Pacific Northwest National Laboratory, under Contract DE–AC05–76RL01830.

[199] IEA (2009), World Energy Outlook 2009, OECD/IEA, Paris.

sequestered, this project clearly demonstrates the technical feasibility of the amine scrubbing system for CO_2 capture from a coal-fired power plant.[200] The fact that this system is an industrial coal-fired power plant rather than a utility coal-fired power plant is irrelevant as they both serve a similar purpose—the production of electricity.

Each of these processes indicate a willingness of industry to utilize available post-combustion technology for capture of CO_2 for commercial purposes. Not one of the CO_2 capture systems at Warrior Run, Shady Point, or Searles Valley was installed for regulatory purposes or as government-funded demonstration projects. They were installed to capture CO_2 for commercial use. The fact that the captured CO_2 was utilized rather than being stored is of no consequence in the consideration of the technical feasibility of post-combustion CO_2 capture technology. These commercial operations have helped to improve the performance of scrubbing systems that are available today. For example, the heat duty (*i.e.,* the energy needed to remove the CO_2) has been reduced by about 5 times from the amine process originally used at the Searles Valley facility. The amine scrubbing process used at Boundary Dam is equally efficient, and the amine scrubbing system to be used at the Petra Nova WA Parish project (Thompsons, TX) is projected to be as well.[201]

3. Post-Combustion Carbon Capture Projects That Received DOE Assistance Through the EPAct05, but Did Not Receive Tax Credits Under IRC Section 48A

The EPA considers the experiences from the CCS projects described above, coupled with evidence that the design of CCS is well accepted (also described above) and the strong support that CCS has received from vendors and others (described below) to adequately demonstrate that post-combustion partial CCS is technically feasible. The EPA finds that additional projects, described next, provide more support for that conclusion. These projects received funding under EPAct05 from the Department of Energy, but that does not disqualify them from being considered. See Section III.H.3 above.

a. Petra Nova WA Parish Project

Petra Nova, a joint venture between NRG Energy Inc. and JX Nippon Oil & Gas Exploration, is constructing a commercial-scale post-combustion carbon capture project at Unit #8 of NRG's WA Parish generating station southwest of Houston, Texas. The project is designed to utilize partial CCS by capturing approximately 90 percent of the CO_2 from a 240 MW slip-stream of the 610 MW WA Parish facility. The project is expected to be operational in 2016 and thus does not yet directly demonstrate the technical feasibility or performance of the MHI amine scrubbing system. However, this project is a clear indication that the developers have confidence in the technical feasibility of the post-combustion carbon capture system.

The project was originally envisioned as a 60 MW slip-stream demonstration and received DOE Clean Coal Power Initiative (CCPI) funding (as provided in EPAct05) on that basis. The developers later expanded the project to the larger 240 MW slip-stream because of the need to capture greater volumes of CO_2 for EOR operations. No additional DOE or other federal funding was obtained for the expansion from a 60 MW slip-stream to a 240 MW slip-stream.[202]

At 240 MW, the Petra Nova project will be the largest post-combustion carbon capture system installed on an existing coal-fueled power plant. The project will use for EOR or will sequester 1.6 million tons of captured CO_2 each year. The project is expected to be operational in 2016.

In 2014 project materials,[203] the project developer NRG recognized the importance of CCS technology by noting:

> The technology has the potential to enhance the long-term viability and sustainability of coal-fueled power plants across the U.S. and around the world. . . . Post-combustion carbon capture is essential so that we can use coal to sustain our energy ecosystem while we begin reducing our carbon footprint.

According to NRG, the Petra Nova Carbon Capture Project will utilize ''a proven carbon capture process,'' jointly developed by Mitsubishi Heavy Industries, Ltd. (MHI) and the Kansai Electric Power Co., that uses a high-performance solvent for CO_2 absorption and desorption.[204] In using the MHI high-performance solvent, the Petra Nova project will benefit from pilot-scale testing of this solvent at Alabama Power's Plant Barry and at other installations. WA Parish Unit #8 came on-line in 1982 and is thus an existing source that will not be subject to final standards of performance issued in this action. However, because it will be capturing roughly 35 percent of the CO_2 generated by the facility, its emissions will be below the final new source emission limitation of 1,400 lb CO_2/MWh-g.[205]

The captured CO_2 from the WA Parish CO_2 Capture Project will be used in EOR operations at mature oil fields in the Gulf Coast region. Using EOR at Hilcorp's West Ranch Oil Field, the production is expected to be boosted from around 500 barrels per day to approximately 15,000 barrels per day. Thus the project will utilize all aspects of CCS by capturing CO_2 at the large coal-fired power plant, compressing the CO_2, transporting it by pipeline to the EOR operations, and injecting it for EOR and eventual geologic storage.

The carbon capture system at WA Parish will utilize a slip-stream configuration. However, as noted, the system is designed to capture roughly 35 percent of the CO_2 from WA Parish Unit #8 (90 percent of the CO_2 from the 240 MW slip-stream from the 610 MW unit). A carbon capture system of the same size as that used at WA Parish could be used to treat a 240 MW slip-stream from a 1,000 MW unit in order to meet the final standard of performance of 1,400 lb CO_2/MWh-g.

Again, the experience at the WA Parish Unit #8 project will be directly transferable to post-combustion capture at a new utility boiler, even though WA Parish Unit #8 is an existing source that has been in operation for over 30 years. In fact, retrofit of such technology at an existing unit can be more challenging than incorporating the technology into the design of a new facility. The

[200] Moreover, the final rule allows alternative means of storage of captured CO_2 based on a case-by-case demonstration of efficacy. See Section V.M.4 below.

[201] The heat duty for the amine scrubbing process used at Searles Valley in the mid-70's was about 12 MJ/mt CO_2 removed as compared to a heat duty of about 2.5 MJ/mt CO_2 removed for the amine processes used at Boundary Dam and to be used at WA Parish. ''From Lubbock, TX to Thompsons, TX—Amine Scrubbing for Commercial CO_2 Capture from Power Plants'', plenary address by Prof. Gary Rochelle at the 12th International Conference on Greenhouse Gas Technology (GHGT–12), Austin, TX (October 2014).

[202] Thus, even if the project received DOE assistance for the initial 60 MW design, the expansion of the project from 60 MW to 240 MW should not be considered a DOE-assisted project. In any case, as described above, even without consideration of this facility at all, other information adequately demonstrates the technical feasibility of post-combustion CCS.

[203] WA Parish CO_2 Capture Project Fact Sheet; available at *www.nrg.com/documents/business/pla-2014-petranova-waparish-factsheet.pdf* (2014).

[204] The WA Parish project (described earlier) will utilize the KM–CDR Process®, which was jointly developed by MHI and the Kansai Electric Power Co., Inc. and uses the proprietary KS–1™ high-performance solvent for the CO_2 absorption and desorption.

[205] Using emissions data reported to the Acid Rain Program, the EPA estimates that the CO_2 emissions from the WA Parish Unit #8 will be 1,250–1,300 lb CO_2/MWh-g during operations with the post-combustion capture system.

experience will be directly transferrable to other types of post-combustion sources including those using different boiler types and those burning different coals. The amine scrubbing and associated systems are not boiler type- or coal-specific. The EPA is unaware of any reasons that the technology utilized at the WA Parish plant would not be transferrable to another utility boiler at a different location at a different elevation or climate, given that the technology is not dependent on either climate or topography.

b. AEP/Alstom Mountaineer Project

In September 2009, AEP began a pilot-scale CCS demonstration at its Mountaineer Plant in New Haven, WV. The Mountaineer Plant is a very large (1,300 MW) coal-fired unit that was retrofitted with Alstom's patented chilled ammonia CO_2 capture technology on a 20 MWe slip-stream of the plant's exhaust flue gas. In May 2011, Alstom Power announced the successful operation of the chilled ammonia CCS validation project. The demonstration achieved capture rates from 75 percent (design value) to as high as 90 percent, and produced CO_2 at a purity of greater than 99 percent, with energy penalties within a few percent of predictions. The facility reported robust steady-state operation during all modes of power plant operation, including load changes, and saw an availability of the CCS system of greater than 90 percent.[206]

AEP, with assistance from the DOE, had planned to expand the slip-stream demonstration to a commercial scale, fully integrated demonstration at the Mountaineer facility. The commercial-scale system was designed to capture at least 90 percent of the CO_2 from 235 MW of the plant's 1,300 MW total capacity. Plans were for the project to be completed in four phases, with the system to begin commercial operation in 2015. However, in July 2011, AEP announced that it would terminate its cooperative agreement with the DOE and place its plans to advance CO_2 capture and storage technology to commercial scale on hold. AEP cited the uncertain status of U.S. climate policy as a contributor to its decision, but did not express doubts about the feasibility of the technology. See Section V.L below.

AEP also prepared a Front End Engineering & Design (FEED) Report,[207] explaining in detail how its pilot-scale work could be scaled up to successful full-scale operation, and to accommodate the operating needs of a full-scale EGU, including reliable generating capacity capable of cycling up and down to accommodate consumer demand. Recommended design changes to accomplish the desired scaling included detailed flue gas specifications, ranges for temperature, moisture and SO_2 content; careful scrutiny of makeup water composition and temperature; quality and quantity of available steam to accommodate heat cycle based on unit load changes; and detailed scrutiny of material and energy balances.[208] See Section V.G.3 below, addressing in more detail the record support for how CCS technology can be scaled up to commercial size in both pre- and post-combustion applications.

c. Southern Company/MHI Plant Barry

In June 2011, Southern Company and Mitsubishi Heavy Industries (MHI) launched operations at a 25 MW coal-fired carbon capture facility at Alabama Power's Plant Barry. The facility, which completed the initial demonstration phase, captured approximately 165,000 metric tons of CO_2 annually at a CO_2 capture rate of over 90 percent. The facility employed the KM CDR Process, which uses a proprietary high performing solvent[209] for CO_2 absorption and desorption that was jointly developed by MHI and Japanese utility Kansai Electric Power Co. The captured CO_2 has been transported via pipeline approximately 12 miles to the Citronelle oil field where it is injected into the Paluxy formation, a saline reservoir, for storage.[210]

Project participants have reported that ''[t]he plant performance was stable at the full load condition with CO_2 capture rate of 500 TPD at 90 percent CO_2 removal and lower steam consumption than conventional capture processes.''[211]

E. Pre-Combustion Carbon Capture

As described earlier, the EPA does not find that IGCC technology—either alone or implementing partial CCS—is part of the BSER for newly constructed steam generating EGUs. However, as noted, there may be specific circumstances and business plans—such as co-production of chemicals or fertilizers, or capture of CO_2 for use in EOR operations—that encourage greater CO_2 emission reductions than are required by this standard. In this section, we describe and justify our conclusion that the technical feasibility of pre-combustion carbon capture is adequately demonstrated, indicating that this could be a viable alternative compliance pathway. First, we explain the technology of pre-combustion capture. We then describe EGUs that have previously utilized or are currently utilizing pre-combustion carbon capture technology. This discussion is complemented by other sections that conclude the technical feasibility of other aspects of partial CCS are adequately demonstrated—namely, post-combustion carbon capture (Section V.D) and sequestration (Sections V.M and V.N). Further, this section's conclusions are reinforced by Section V.F, in which we identify commercial vendors that offer CCS performance guarantees as well as developers that have publicly stated their confidence in CCS technologies.

1. Pre-Combustion Carbon Capture—How It Works

Pre-combustion capture systems are typically used with IGCC processes. In a gasification system, the fuel (usually coal or petroleum coke) is heated with water and oxygen in an oxygen-lean environment. The coal (carbon), water and oxygen react to form primarily a mixture of hydrogen (H_2) and carbon monoxide (CO) known as synthesis gas or syngas according to the following high temperature reaction:

$$3C + H_2O + O_2 \rightarrow H_2 + 3CO$$

In an IGCC system, the resulting syngas, after removal of the impurities, can be combusted using a conventional combustion turbine in a combined cycle configuration (*i.e.,* a combustion turbine combined with a HRSG and steam turbine). The gasification process also typically produces some amount of CO_2[212] as a by-product along with other

[206] *http://www.alstom.com/press-centre/2011/5/alstom-announces-sucessful-results-of-mountaineer-carbon-capture-and-sequestration-ccs-project/.*

[207] ''CCS front end engineering & design report: American Electric Power Mountaineer CCS II Project. Phase 1'', pp 10–11; available at: *http://www.globalccsinstitute.com/publications/aep-mountaineer-ii-project-front-end-engineering-and-design-feed-report.*

[208] Id. at 11. The EPA does not view this information as being affected by the constraints in EPAct05. The information does not relate to use of technology, level of emission reduction by reason of use of technology, achievement of emission reduction by demonstration of technology, or demonstration of a level of performance. The FEED study rather explains engineering challenges which would remain at full scale and how those challenges can be addressed.

[209] This is the same carbon capture system that is being utilized at the Petra Nova project at the NRG WA Parish plant.

[210] Ivie, M.A. et al.; ''Project Status and Research Plans of 500 TPD CO_2 Capture and Sequestration Demonstration at Alabama Power's Plant Barry'', *Energy Procedia* 37, 6335 (2013).

[211] Id.

[212] The amount of CO_2 in syngas depends upon the specific gasifier technology used, the operating conditions, and the fuel used; but is typically less

gases (*e.g.,* H_2S) and inorganic materials originating from the coal (*e.g.,* minerals, ash). The amount of CO_2 in the syngas can be increased by ''shifting'' the composition via the catalytic water-gas shift (WGS) reaction. This process involves the catalytic reaction of steam (''water'') with CO (''gas'') to form H_2 and CO_2 according to the following catalytic reaction:

$$CO + H_2O \rightarrow CO_2 + H_2$$

An emission standard that requires partial capture of CO_2 from the syngas could be met by adjusting the level of CO_2 in the syngas stream by controlling the level of syngas ''shift'' prior to treatment in the pre-combustion acid gas treatment system. If a high level of CO_2 capture is required, then multi-stage WGS reactors will be needed and an advanced hydrogen turbine will likely be needed to combust the resulting hydrogen-rich syngas.

Most syngas streams are at higher pressure and can contain higher concentrations of CO_2 (especially if shifted to enrich the concentration). As such, the pre-combustion capture systems can utilize physical absorption (physisorption) solvents rather than the chemical absorptions solvents described earlier. Physical absorption has the benefit of relying on weak intermolecular interactions and, as a result, the absorbed CO_2 can often be released (desorbed) by reducing the pressure rather than by adding heat. Pre-combustion capture systems have been used widely in industrial processes such as natural gas processing.

Additional information on pre-combustion carbon capture can be found in a summary technical support document.[213]

2. Pre-Combustion Carbon Capture Projects That Have Not Received DOE Assistance Through EPAct05 or Tax Credits Under IRC Section 48A

a. Dakota Gasification Great Plains Synfuels Plant

Each day, the Dakota Gasification Great Plains Synfuels Plant uses approximately 18,000 tons of North Dakota lignite in a coal gasification process that produces syngas (a mixture of CO, CO_2, and H_2), which is then converted to methane gas (synthetic natural gas) using a methanation process. Each day, the process produces an average of 145 million cubic feet of synthetic natural gas that is ultimately transported for use in home heating and electricity generation.[214]

Capture of CO_2 from the facility began in 2000. The Synfuels Plant, using a pre-combustion Rectisol® process, captures about 3 million tons of CO_2 per year—more CO_2 from coal conversion than any facility in the world, and is a participant in the world's largest carbon sequestration project. On average about 8,000 metric tons per day of captured CO_2 from the facility is sent through a 205-mile pipeline to oil fields in Saskatchewan, Canada, where it is used for EOR operations that result in permanent CO_2 geologic storage. The geologic sequestration of CO_2 in the oil reservoir is monitored by the International Energy Agency (IEA) Weyburn CO_2 Monitoring and Storage Project.

Several commenters to the January 2014 proposal argued that the Great Plains Synfuels facility is not an EGU, that it operates as a chemical plant, and that its experience is not translatable to an IGCC using pre-combustion carbon capture technology. The commenters noted that the Dakota facility can be operated nearly continuously without the need to adjust operations to meet cyclic electricity generation demands. In the January 2014 proposal, the EPA had noted that, while the facility is not an EGU, it has significant similarities to an IGCC and the implementation of the pre-combustion capture technology would be similar enough for comparison. See 79 FR at 1435–36 and n. 11. We continue to hold this view.

As explained above, in an IGCC gasification system, coal (or petroleum coke) is gasified to produce a synthesis gas comprised of primarily CO, H_2, and some amount of CO_2 (depending on the gasifier and the specific operating conditions). A water-gas-shift reaction using water (H_2O, steam) is then used to shift the syngas to CO_2 and H_2. The more the syngas is ''shifted,'' the more enriched it becomes in H_2. In an IGCC, power can be generated by directly combusting the un-shifted syngas in a conventional combustion turbine. If the syngas is shifted such that the resulting syngas is highly enriched in H_2, then a special, advanced hydrogen turbine is needed. If CO_2 is to be captured, then the syngas would need to be shifted either fully or partially, depending upon the level of capture required.[215]

The Dakota Gasification process bears essential similarities to the just-described IGCC gasification system. As with the IGCC gasification system, the Dakota Gasification facility gasifies coal (lignite) to produce a syngas which is then shifted to increase the concentration of CO_2 and to produce the desired ratio of CO and H_2. As with the IGCC gasification system, the CO_2 is then removed in a pre-combustion capture system, and the syngas that results is made further use of. For present purposes, only the manner in which the syngas is used distinguishes the IGCC gasification system from the Dakota Gasification facility. In the IGCC process, the syngas is combusted. In the Dakota Gasification facility, the syngas is processed through a catalytic methanation process where the CO and H_2 react to produce CH_4 (methane, synthetic natural gas) and water. Importantly, the CO_2 capture system that is used in the Dakota Gasification facility can readily be used in an IGCC EGU. There is no indication that the RECTISOL® process (or other similar physical gas removal systems) is not feasible for an IGCC EGU. In confirmation, according to product literature, RECTISOL®, which was independently developed by Linde and Lurgi, is frequently used to purify shifted, partially shifted or un-shifted gas from the gasification of coal, lignite, and residual oil.[216]

b. International Projects

There are some international projects that are in various stages of development that indicate confidence by developers in the technical feasibility of pre-combustion carbon capture. Summit Carbon Capture, LLC is developing the Caledonia Clean Energy Project, a proposed 570-megawatt IGCC plant with 90 percent CO_2 capture that would be built in Scotland, U.K. Captured CO_2 from the plant will be transported via on-shore and sub-sea pipeline for sequestration in a saline formation in the North Sea. The U.K. Department of Energy & Climate Change (DECC) recently announced funding to allow for feasibility studies for this plant.[217] Commercial operation is expected in 2017.[218]

The China Huaneng Group—with multiple collaborators, including Peabody Energy, the world's largest private sector coal company—is building the 400 MW GreenGen IGCC

than 20 volume percent (*http://www.netl.doe.gov/research/coal/energy-systems/gasification/gasifipedia/syngas-composition*).

[213] Technical Support Document—''Literature Survey of Carbon Capture Technology'', available in the rulemaking docket (Docket ID: EPA–HQ–OAR–2013–0495).

[214] *http://www.dakotagas.com/Gasification/.*

[215] ''Cost and Performance of PC and IGCC for a Range of Carbon Capture'', Rev 1 (2013), DOE/NETL–2011/1498.

[216] *www.linde-engineering.com/en/process_plants/hydrogen_and_synthesis_gas_plants/gas_processing/rectisol_wash/index.html.*

[217] *http://www.downstreambusiness.com/item/Summit-Power-Wins-Funding-Studies-Proposed-IGCC-CCS-Project_140878.*

[218] *http://www.summitpower.com/projects/carbon-capture/.*

facility in Tianjin City, China. The goal is to complete the power plant before 2020. Over 80 percent of the CO_2 will be separated using pre-combustion capture technology. The captured CO_2 will be used for EOR operations.[219]

Vattenfall and Nuon's pilot project in Bugennum, The Netherlands involves carbon capture from coal- and biomass-fired IGCC plants. It has operated since 2011.[220]

Approximately 100 tons of CO_2 per day are captured from a coal- and petcoke-fired IGCC plant in Puertollano, Spain. The facility began operating in 2010.[221]

Emirates Steel Industries is expected to capture approximately 0.8Mt of CO_2 per year from a steel-production facility in the United Arab Emirates. Full-scale operations are scheduled to begin by 2016.[222]

The Uthmaniyah CO_2 EOR Demonstration Project in Saudi Arabia will capture 0.8 Mt of CO_2 from a natural gas processing plant over three years. It is expected to begin operating in 2015.[223]

The experience of the Dakota Gasification facility, coupled with the descriptions of the technology in the literature, the statements from vendors, and the experience of facilities internationally, are sufficient to support our determination that the technical feasibility of CCS for an IGCC facility is adequately demonstrated. The experience of additional facilities, described next, provides additional support.

3. Pre-Combustion Carbon Capture Projects That Have Received DOE Assistance Through EPAct05, but Did Not Receive Tax Credits Under IRC Section 48A

a. Coffeyville Fertilizer

Coffeyville Resources Nitrogen Fertilizers, LLC, owns and operates a nitrogen fertilizer facility in Coffeyville, Kansas. The plant began operation in 2000 and is the only one in North America using a petroleum coke-based fertilizer production process. The petroleum coke is generated at an oil refinery adjacent to the plant. The petroleum coke is gasified to produce a hydrogen rich synthetic gas, from which ammonia and urea ammonium nitrate fertilizers are subsequently synthesized.

As a by-product of manufacturing fertilizers, the plant also produces significant amounts of CO_2. In March 2011, Chaparral Energy announced a long-term agreement for the purchase of captured CO_2 which is transported 68 miles via CO_2 pipeline for use in EOR operations in Osage County, OK. Injection at the site started in 2013.

At least one commenter suggested that the cost and complexity of carbon capture from these and other industrial projects was significantly decreased because the sources already separate CO_2 as part of their normal operations. The EPA finds this argument unconvincing. The Coffeyville process involves gasification of a solid fossil fuel (pet coke), shifting the resulting syngas stream, and separation of the resulting CO_2 using a pre-combustion carbon capture system. These are the same, or very similar, processes that are used in an IGCC EGU. The argument is even less convincing when considering that the Coffeyville Fertilizer process uses the Selexol™ pre-combustion capture process—the same process that Mississippi Power described as having been ''in commercial use in the chemical industry for decades'' and is expected by Mississippi Power to ''pose little technology risk'' when used at the Kemper IGCC EGU.

4. Pre-Combustion Carbon Capture Projects That Have Received DOE Assistance Through EPAct05 and Tax Credits Under IRC Section 48A

a. Kemper County Energy Facility

Southern Company's subsidiary Mississippi Power has constructed the Kemper County Energy Facility in Kemper County, MS. This is a 582 MW IGCC plant that will utilize local Mississippi lignite and includes a pre-combustion carbon capture system to reduce CO_2 emissions by approximately 65 percent. The pre-combustion solvent, Selexol™ has also been used extensively for acid gas removal (including for CO_2 removal) in various processes. In filings with the Mississippi Public Service Commission for the Kemper project, Mississippi described the carbon capture system:

> The Kemper County IGCC Project will capture and compress approximately 65% of the Plant's CO_2 [. . .] a process referred to as Selexol™ is applied to remove the CO_2 such that it is suitable for compression and delivery to the sequestration and EOR process. [. . .] *The carbon capture equipment and processes proposed in this project have been in commercial use in the chemical industry for decades and pose little technology risk.* (emphasis added)[224]

Thus, Mississippi Power believes that, because the Selexol™ process has been in commercial use in the chemical industry for decades, it is well proven, and will pose little technical risk when used in the Kemper IGCC EGU.

b. Texas Clean Energy Project and Hydrogen Energy California Project

The Texas Clean Energy Project (TCEP), a 400 MW IGCC facility located near Odessa, Texas will capture 90 percent of its CO_2, which is approximately 3 million metric tons annually. The captured CO_2 will be used for EOR in the West Texas Permian Basin. Additionally, the plant will produce urea and smaller quantities of commercial-grade sulfuric acid, argon, and inert slag, all of which will also be marketed. Summit has announced that they expect to commence construction on the project in 2015.[225] The facility will utilize the Linde Rectisol® gas cleanup process to capture carbon dioxide[226]—the same process that has been deployed for decades, including at the Dakota Gasification facility, a clear indication of the developer's confidence in that technology and further evidence that the Dakota Gasification carbon capture technology is transferable to EGUs.

F. Vendor Guarantees, Industry Statements, Academic Literature, and Commercial Availability

In this section, we describe additional information that supports our determination that CCS is adequately demonstrated to be technically feasible. This includes performance guarantees from vendors, public statements from industry officials, and review of the literature.

1. Performance Guarantees

The D.C. Circuit made clear in its first cases concerning CAA section 111 standards, and has affirmed since then,

[219] *http://sequestration.mit.edu/tools/projects/greengen.html.*

[220] Buggenum Fact Sheet: Carbon Dioxide Capture and Storage Project, Carbon Capture & Sequestration Technologies @MIT, *http://sequestration.mit.edu/tools/projects/buggenum.html.*

[221] Puertollano Fact Sheet: Carbon Dioxide Capture and Storage Project, Carbon Capture & Sequestration Technologies @MIT, *https://sequestration.mit.edu/tools/projects/puertollanto.html.*

[222] ESI CCS Project Fact Sheet: Carbon Dioxide and Storage Project, Carbon Capture & Sequestration Technologies @MIT, *https://sequestration.mit.edu/tools/projects/esi_ccs.html* and *https://www.globalccsinstitute.com/projects/large-scale-ccs-projects.*

[223] Uthmaniyah CO_2 EOR Demonstration Project, Global CCS Institute, *https://www.globalccsinstitute.com/projects/large-scale-ccs-projects.*

[224] Mississippi Power Company, Kemper County IGCC Certificate Filing, Updated Design, Description and Cost of Kemper IGCC Project, Mississippi Public Service Commission (MPSC) DOCKET NO. 2009–UA–0014, filed December 7, 2009.

[225] ''Odessa coal-to-gas power plant to break ground this year'', Houston Chronicle (April 1, 2015).

[226] *http://www.texascleanenergyproject.com/project/.*

that performance guarantees from vendors are an important basis for supporting a determination that pollution technology is adequately demonstrated to be technically feasible. In 1973, in *Essex Chem. Corp.* v. *Ruckelshaus,* 486 F.2d 427, 440 (D.C. Cir. 1973), the Court upheld standards of performance for coal-fired steam generators based on ''prototype testing data and full-scale control systems, considerations of available fuel supplies, literature sources, and *documentation of manufacturer guarantees and expectations*'' (emphasis supplied)).[227] Subsequently, in *Sierra Club* v. *Costle,* the Court noted, in upholding the standard: ''we find it informative that the vendors of FGD equipment corroborate the achievability of the standard.'' [228]

Linde and BASF offer performance guarantees for carbon capture technology. The two companies are jointly marketing new, advanced technology for capturing CO_2 from low pressure gas streams in power or chemical plants. In product literature,[229] they note that Linde will provide a turn-key carbon capture plant using a scrubbing process and solvents developed by BASF, one of the world's leading technical suppliers for gas treatment. They further note that:

> The captured carbon dioxide can be used commercially for example for EOR (enhanced oil recovery) or as a building block for the production of urea. Alternatively it can be stored underground as a carbon abatement measure. [. . .] The PCC (Post-Combustion Capture) technology *is now commercially available* for lignite and hard coal fired power plant [. . .] applications.
>
> The alliance between Linde, a world-leading gases and engineering company and BASF, the chemical company, offers great benefits [. . .] Complete capture plants including CO_2 compression and drying . . . Proven and tested processes *including guarantee . . .* Synergies between process, engineering, construction and operation . . . Optimized total and operational costs for the owner. (emphasis added)

In addition, other well-established companies that either offer technologies that are actively marketed for CO_2 capture from fossil fuel-fired power plants or that develop those power plants, have publicly expressed confidence in the technical feasibility of carbon capture. For example, Fluor has developed patented CO_2 recovery technologies to help its clients reduce GHG emissions. The Fluor product literature [230] specifically points to the Econamine FG Plus℠ (EFG+) process, which uses an amine solvent to capture and produce food grade CO_2 from post-combustion sources. The literature further notes that EFG+ is also used for carbon capture and sequestration projects, that the proprietary technology provides a proven, cost-effective process for the removal of CO_2 from power plant flue gas streams, and that the process can be customized to meet a power plant's unique site requirements, flue gas conditions, and operating parameters.

Fluor has also published an article titled ''Commercially Available CO_2 Capture Technology'' in which it describes the EFG+ technology.[231] The article notes, ''Technology for the removal of carbon dioxide (CO_2) from flue gas streams has been around for quite some time. The technology was developed not to address the GHG effect but to provide an economic source of CO_2 for use in enhanced oil recovery and industrial purposes, such as in the beverage industry.''

Mitshubishi Heavy Industries (MHI) offers a CO_2 capture system that uses a proprietary energy-efficient CO_2 absorbent called KS–1™. Compared with the conventional monoethanolamine (MEA)-based absorbent, KS–1™ solvent requires less solvent circulation to capture the CO_2 and less energy to recover the captured CO_2.

In addition, Shell has developed the CANSOLV CO_2 Capture System, which Shell describes in its product literature [232] as a world leading amine based CO_2 capture technology that is ideal for use in fossil fuel-fired power plants where enormous amounts of CO_2 are generated. The company also notes that the technology can help refiners, utilities, and other industries lower their carbon intensity and meet stringent GHG abatement regulations by removing CO_2 from their exhaust streams, with the added benefit of simultaneously lowering SO_2 and NO_2 emissions.

At least one commenter suggested that it is unlikely that any vendor is willing or able to provide guarantees of the performance of the system as a whole, arguing that this shows the system isn't adequately demonstrated.[233] However, this suggestion is inconsistent with the performance guarantees offered for other air pollution control equipment. Particulate matter (PM) is controlled in the flue gas stream of a coal-fired power plant using fabric filters or electrostatic precipitators (ESP). The captured PM is then moved using PM/ash handling systems and is then transported for storage or re-use. It is unlikely that a fabric filter or ESP vendor would provide a performance guarantee for ''the system as a whole.'' Similarly, a wet-FGD scrubber vendor would not be expected to provide a performance guarantee for handling, transportation, and re-use of scrubber solids for gypsum wallboard manufacturing. CO_2 capture, transportation, and storage should, similarly, not be viewed as a single technology. Rather, these should be viewed as components of an overall system of emission reduction. Different companies will have expertise in each of these components, but it is unlikely that a single technology vendor would provide a guarantee for ''the system as a whole.''

2. Academic and Other Literature

Climate change mitigation options—including CCS—are the subject of great academic interest, and there is a large body of academic literature on these options and their technical feasibility. In addition, other research organizations (*e.g.,* U.S. national laboratories and others) have also published studies on these subjects that demonstrate the availability of these technologies. A compendium of relevant literature is provided in a Technical Support Document available in the rulemaking docket.[234]

3. Additional Statements by Technology Developers

The discussion above of vendor guarantees, positive statements by industry officials, and the academic literature supports the EPA's determination that partial CCS is adequately demonstrated to be

[227] *See* also *Portland Cement Ass'n* v. *Ruckelshaus,* 486 F.2d 375, 401–02 (D.C. Cir. 1973) (''It would have been entirely appropriate if the Administrator had justified the standards . . . on testimony from experts and vendors made part of the record.'').

[228] *Sierra Club* v. *Costle,* 657 F.2d 298, 364 (D.C. Cir. 1981). *See* also *National Petrochem & Refiners Assn* v. *EPA,* 287 F. 3d 1130, 1137 (D.C. Cir. 2002) (noting that vendor guarantees are an indicia of availability and achievability of a technology-based standard since, notwithstanding a desire to promote sales, ''a manufacturer would risk a considerable loss of reputation if its technology could not fulfill a mandate that it had persuaded EPA to adopt'').

[229] *www.intermediates.basf.com/chemicals/web/gas-treatment/en/function/conversions:/publish/content/products-and-industries/gas-treatment/images/Linde_and_BASF-Flue_Gas_Carbon_Capture_Plants.pdf.*

[230] *www.fluor.com/client-markets/energy-chemicals/Pages/carbon-capture.aspx.*

[231] *http://www.powermag.com/commercially-available-co2-capture-technology/.*

[232] *http://www.shell.com/global/products-services/solutions-for-businesses/globalsolutions/shell-cansolv/shell-cansolv-solutions/co2-capture.html.*

[233] Comments of Murray Energy, p. 73, (Docket entry: EPA–HQ–OAR–2013–0495–10046).

[234] Technical Support Document—''Literature Survey of Carbon Capture Technology'', available in the rulemaking docket (Docket ID: EPA–HQ–OAR–2013–0495).

technically feasible. Industry officials have made additional positive statements in conjunction with facilities that received DOE assistance under EPAct05 or the IRC Section 48A tax credit. These statements provide further, although not necessary, support.

For example, Southern Company's Mississippi Power has stated that, because the Selexol™ process has been used in industry for decades, the technical risk of its use at the Kemper IGCC facility is minimized. For example:

The carbon capture process being utilized for the Kemper County IGCC is a commercial technology referred to as Selexol™. The Selexol™ process is a commercial technology that uses proprietary solvents, but is based on a technology and principles that have been in commercial use in the chemical industry for over 40 years. Thus, the risk associated with the design and operation of the carbon capture equipment incorporated into the Plant's design is manageable.[235]

And . . .

The carbon capture equipment and processes proposed in this project have been in commercial use in the chemical industry for decades and pose little technology risk.[236]

Similarly, in an AEP Second Quarter 2011 Earnings Conference Call, Chairman and CEO Mike Morris said of the Mountaineer CCS project:

We are encouraged by what we saw, we're clearly impressed with what we learned, and we feel that we have demonstrated to a certainty that the carbon capture and storage is in fact viable technology for the United States and quite honestly for the rest of the world going forward.[237]

Some commenters have claimed that CCS technology is not technically feasible, and some further assert that vendors do not offer performance guarantees. For example, Alstom commented:

The EPA referenced projects fail to meet the 'technically feasible' criteria. These technologies are not operating at significant scale at any site as of the rule publication. We do not support mandating technology based on proposed projects (many of which may never be built).[238]

As discussed above, vendors do in fact offer performance guarantees. We further note that, as noted above, Boundary Dam Unit #3 is a full-scale project that is successfully implementing full CCS with post-combustion capture, and Dakota Gasification is likewise a full-scale commercial operation that is successfully implementing pre-combustion CCS technology. Moreover, as we explain above, this technology and performance is transferable to the steam electric generating sector. In addition, as noted above, technology providers and technology end users have expressed confidence in the availability and performance of CCS technology.[239]

G. Response to Key Comments on the Adequacy of the Technical Feasibility Demonstration

1. Commercial Availability

Some commenters asserted that CCS cannot be considered the BSER because it is not commercially available. There is no requirement, as part of the BSER determination, that the EPA finds that the technology in question is ''commercially available.'' As we described in the January 2014 proposal, the D.C. Circuit has explained that a standard of performance is ''achievable'' if a technology or other system of emission reduction can reasonably be projected to be available to new sources at the time they are constructed that will allow them to meet the standard, and that there is no requirement that the technology ''must be in routine use somewhere.'' See *Portland Cement* v. *Ruckelshaus,* 486 F. 2d at 391; 79 FR 1463. In any case, as discussed above, CCS technology is available through vendors who provide performance guarantees, which indicates that in fact, CCS is commercially available, which adds to the evidence that the technology is adequately demonstrated to be technically feasible. In sum, ''[t]he capture and CO_2 compression technologies have commercial operating experience with demonstrated ability for high reliability.'' [240]

2. Must a technology or system of emission reduction be in full-scale use to be considered demonstrated?

Commenters maintained that the EPA can only show that a BSER is ''adequately demonstrated'' using operating data from the technology or system of emission reduction itself. This is mistaken. Since the very inception of the CAA section 111 program, courts have noted that ''[i]t would have been entirely appropriate if the Administrator had justified the standard, not on the basis of tests on existing sources or old test data in the literature, but on extrapolations from this data, on a reasoned basis responsive to comments, and on testimony from experts and vendors . . . .'' *Portland Cement* v. *Ruckelshaus,* 486 F. 2d at 401–02.[241]

In a related argument, other commenters stated that a system cannot be adequately demonstrated unless all of its component parts are operating together.[242] Courts have, in fact, accepted that the EPA can legitimately infer that a technology is demonstrated as a whole based on operation of component parts which have not, as yet, been fully integrated. *Sur Contra la Contaminacion* v. *EPA,* 202 F. 3d 443, 448 (1st Cir. 2000); *Native Village of Point Hope v Salazar* 680 F. 3d 1123, 1133 (9th Cir. 2012). Moreover, all components of CCS are fully integrated at Boundary Dam: Post-combustion full CCS is being utilized at a steam electric fossil fuel-fired plant, with captured carbon being transported via dedicated pipeline to both sequestration and EOR sites. All components are likewise demonstrated for pre-combustion CCS at the Dakota Gasification facility, except that the facility does not generate electricity, a distinction without a difference for this purpose (see Section V.E.2.a above).

The short of it is that the ''EPA does have authority to hold the industry to a standard of improved design and

[235] Testimony of Thomas O. Anderson, Vice President, Generation Development for Mississippi Power, MS Public Service Commission Docket 2009–UA–14 at 22 (Dec. 7, 2009).

[236] Mississippi Power Company, Kemper County IGCC Certificate Filing, Updated Design, Description and Cost of Kemper IGCC Project, Mississippi Public Service Commission (MPSC) DOCKET NO. 2009–UA–0014, filed December 7, 2009.

[237] American Electric Power Co Inc AEP Q2 2011 Earnings Call Transcript, Morningstar, *http://www.morningstar.com/earnings/28688913-american-electric-power-co-incaep-q2–2011-earnings-call-transcript.aspx.*

[238] Alstom Comments, p. 3 (Docket entry: EPA–HQ–OAR–2013–0495–9033).

[239] We note that before filing comments for this rule asserting that CCS is not technically feasible, Alstom issued public statements that, like the other industry officials quoted above, affirmed that CCS is technically feasible. According to an Alstom Power press release, Alstom President Phillipe Joubert, referencing results from an internal Alstom study, stated at an industry meeting: ''We can now be confident that carbon capture technology (CCS) works and that it is cost-effective''. *http://www.alstom.com/press-centre/2011/6/2011-06-16-CCS-cost-competiveness/.*

[240] ''Cost and Performance Baseline for Fossil Energy Plants Volume 1a: Bituminous Coal (PC) and Natural Gas to Electricity Revision 3'', DOE/NETL–2015/1723 (July 2015) at p. 36.

[241] More recently, the D.C. Circuit stated:

Our prior decisions relating to technology-forcing standards are no bar to this conclusion. We recognize here, as we have recognized in the past, that an agency may base a standard or mandate on future technology when there exists a rational connection between the regulatory target and the presumed innovation.

API v. *EPA,* 706 F. 3d at 480 (D.C. Cir. 2013) (citing the section 111 case *Sierra Club* v. *Costle,* 657 F. 2d at 364). The Senate Report to the original section 111 likewise makes clear that it was not intended that the technology ''must be in actual routine use somewhere.'' Rather, the question was whether the technology would be available for installation in new plants. S. Rep. No. 91–1196, 91st Cong., 2d Sess. 16 (1970).

[242] See, *e.g.,* Comments of UARG p. 5 (Docket entry: EPA–HQ–OAR–2013–0495–9666).

operational advances, so long as there is substantial evidence that such improvements are feasible and will produce the improved performance necessary to meet the standard.'' *Sierra Club,* 657 F. 2d at 364. The EPA's task is to ''identify the major steps necessary for development of the device, and give plausible reasons for its belief that the industry will be able to solve those problems in the time remaining''. *API* v. *EPA,* 706 F. 3d at 480 (quoting *NRDC* v. *EPA,* 655 F. 2d 318, 333 (D.C. Cir. 1981), and citing *Sierra Club* for this proposition).

3. Scalability of Pilot and Demonstration Projects

Commenters maintained that the EPA had no basis for maintaining that pilot and demonstration plant operations showed that CCS was adequately demonstrated. This is mistaken. In a 1981 decision, *Sierra Club* v. *Costle,* the D.C. Circuit explained that data from pilot-scale, or less than full-scale operation, can be shown to reasonably demonstrate performance at full-scale operation, although it is incumbent on the EPA to explain the necessary steps involved in scaling up a technology and how any obstacles may reasonably be surmounted when doing so.[243] The EPA has done so here.

Most obviously, the final standard reflects experience of full-scale operation of post-combustion carbon capture. Pre-combustion carbon capture is likewise demonstrated at full-scale. Second, the record explains in detail how CCS can be implemented at full-scale. The NETL cost and performance reports, indeed, contain hundreds of pages of detailed, documented explanation of how CCS can be implemented at full-scale for both utility boiler and IGCC facilities. See, for example, the detailed description of the following systems projected to be needed for a new supercritical PC boiler to capture CO_2: Coal and sorbent receiving and storage, steam generator and ancillaries, NO_X control system, particulate control, flue gas desulfurization, flue gas system, CO_2 recovery facility, steam turbine generator system, balance of plant, and accessory electric plant, and instrumentation and control systems.[244]

It is important to note that, while some commenters challenged the EPA's use of costs in the DOE/NETL cost and performance reports, commenters did not challenge the technical methodology in the work.

In addition, the AEP FEED study indicates how the development scale post-combustion CCS could be successfully scaled up to full-scale operation. See Section V.D.3.b above.

Tenaska Trailblazer Partners, LLC also prepared a FEED study[245] for the carbon capture portion of the previously proposed Trailblazer Energy Center, a 760 MW SCPC EGU that was proposed to include 85 to 90 percent CO_2 post-combustion capture. Tenaska selected the Fluor Econamine FG Plus℠ technology and contracted Fluor to conduct the FEED study. One of the goals of the FEED study was to ''[c]onfirm that scale up to a large commercial size is achievable.'' Tenaska ultimately concluded that the study had achieved its objectives resulting in ''[c]onfirmation that the technology can be scaled up to constructable design at commercial size through (1) process and discipline engineering design and CFD (computational fluid dynamics) analysis, (2) 3D model development, and (3) receipt of firm price quotes for large equipment.''

Much has been written about the complexities of adding CCS systems to fossil fuel-fired power plants. Some of these statements come from high government officials. Some commenters argued that the EPA minimized—or even ignored—these publically voiced concerns in the discussion presented in the January 2014 proposal. On the contrary, the EPA has not minimized or ignored these complexities, but it is important to realize that most of these statements come in a different context: Namely, implementing full CCS, or retrofitting CCS onto existing power plants. For example, in the Final Report of the President's CCS Task Force, it was noted that ''integration of CCS technologies with the power cycle at generating plants can present significant cost and operating issues that will need to be addressed to facilitate widespread, cost-effective deployment of CO_2 capture.''[246] This statement—and most of the statements in this vein—are in reference to implementation of full CCS systems that capture more than 90 percent of the CO_2 and many reference widespread implementation of such technology. The EPA has addressed the concerns regarding ''significant cost'' by finalizing a standard that relies on partial CCS which we show, in this preamble and in the supporting record, can be implemented at a reasonable, non-exorbitant cost. The Boundary Dam facility, in particular, demonstrates that the complexities of implementing CCS—even full CCS—can be overcome.

Concerns regarding ''operating issues'' are also often associated with implementation of full CCS—and often with implementation of full CCS as a retrofit to an existing source. Implementation of CCS at some existing sources may be challenging because of space limitations. That should not be an issue for a new facility because the developer will need to ensure that adequate space is available during the design of the facility. Constructing CCS technology at an existing facility can be challenging even if there is adequate space because the positioning of the equipment may be awkward when it must be constructed to fit with the existing equipment at the plant. Some commenters noted the challenges of diverting steam from the plant's steam cycle. Again, that is primarily an issue with full CCS implementation as a retrofit to an existing source. Consideration of steam requirements for solvent regeneration can be factored into the design of a new facility. We also note that issues of integration with the plant's steam cycle are less challenging when implementing partial CCS.

Some commenters noted conclusions and statements from the CCS Task Force report as contradictory to the EPA's determination of that partial CCS is technically feasible and adequately demonstrated. However, the EPA mentioned in the January 2014

[243] *Sierra Club* v. *Costle,* 657 F. 2d 298, 341 n.157 and 380–84 (D.C. Cir. 1981). See also *Essex Chemical Corp.* v. EPA, 486 F. 2d at 440 (upholding achievability of standard of performance for coal-burning steam generating plants which hadn't been achieved in full-scale performance based in part on ''prototype testing data'' which, along with vendor guarantees, indicated that the promulgated standard was achievable); *Weyerhaeuser* v. *Costle,* 590 F. 2d 1054 n. 170 (D.C. Cir. 1978) (use of pilot plant information to justify technology-based standard for Best Available Technology Economically Achievable under section 304 of the Clean Water Act); *FMC Corp.* v. *Train,* 539 F. 2d 973, 983–84 (4th Cir. 1976)(same).

[244] Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity; Revision 2a, pp. 57–74.

[245] Final front-end engineering design (FEED) study report'', available at: *www.globalccsinstitute.com/publications/tenaska-trailblazer-front-end-engineering-design-feed-study.*

[246] Report of the Interagency Task Force on Carbon Capture and Storage (August 2010), page 28. See also DOE Carbon Capture Web site: ''First generation CO_2 capture technologies are currently being used in various industrial applications. However, in their current state of development, these technologies are not ready for implementation on coal-based power plants because they have not been demonstrated at appropriate scale, requisite approximately one-third of the plant's steam power to operate, and are cost prohibitive.'' (Dec 2010); and Testimony of Dr. S. Julio Friedmann, Deputy Asst. Secretary of Energy for Clean Coal, U.S. Dept. of Energy, before the Subcommittee on Oversight and Investigations Committee on Energy and Commerce (Feb. 11, 2014): CCS technologies at new coal-fired plants would result in ''something like a 70 to 80 percent increase on the wholesale price of electricity.''

proposal, and we emphasize again here, that the Task Force was charged with proposing a plan to overcome the barriers to the widespread, cost-effective deployment of CCS by 2020. Implicit in all of the conclusions, recommendations, and statements of that final report is a goal of widespread implementation of full CCS—including retrofits of existing sources. This final action does not require—nor does it envision—the near term widespread implementation of full CCS. On the contrary, as we have noted several times in this preamble, the EPA and others predict that very few, if any, new coal-fired steam generating EGUs will be built in the near term.

Thus, the EPA has provided an ample record supporting its finding that partial CCS is feasible at full-scale. As in *Sierra Club,* the EPA has presented evidence from full-scale operation, smaller scale installations, and reasonable, corroborated technical explanations of how the BSER can be successfully operated at full scale. See 657 F. 2d at 380, 382. Indeed, the EPA has more evidence here, as the baghouse standard in *Sierra Club* was justified based largely on less-than-full-scale operation. See 657 F.2d at 380 (there was only ''limited data from one full scale commercial sized operation''), 376 (''the baghouses surveyed were installed at small plants''), and 341 n.157; see also Section V.L, explaining why CCS is a more developed technology than FGD scrubbers were at the inception of the 1971 NSPS for this industry.

H. Consideration of Costs

CAA section 111(a) defines ''standard of performance'' as an emission standard that reflects the best system of emission reduction that is adequately demonstrated, ''taking into account [among other things] the cost of achieving such reduction.'' Based on consideration of relevant cost metrics in the context of current market conditions, the EPA concludes that the costs associated with the final standard are reasonable.

In reaching this determination, the EPA considered a host of different cost metrics, each of which illuminated a particular aspect of cost consideration, and each of which demonstrated that the costs of the final standard are reasonable. The EPA evaluated capital costs on a per-plant basis, responding to public comment that noted the particular significance of capital costs for coal-fired EGUs. As in the proposal, the EPA also considered how the standard would affect the LCOE for individual affected EGUs as well as national, overall cost impacts of the standard. The EPA found that the anticipated cost impacts are similar to those in other promulgated NSPS—including for this industry—that have been upheld by the D.C. Circuit. The costs are also comparable to those of other base load technologies that might be selected on comparable energy portfolio diversity grounds. Finally, the EPA does not anticipate any significant overall nationwide costs or cost impacts on consumers because projected new generating capacity is expected to meet the standards even in the baseline. Accordingly, after considering costs from a range of different perspectives, the EPA concludes that the costs of the final standard are reasonable.

1. Rationale at Proposal

At proposal, the EPA evaluated the costs of new coal-fired EGUs implementing full (90 percent) and partial CCS. The EPA compared the predicted LCOE of those units against the LCOE of other new dispatchable technologies often considered for new base load power with fuel diversity, primarily including a new nuclear plant, as well as a new biomass-fired EGU. See 79 FR at 1475–78. The levelized cost for a new steam EGU implementing full CCS was higher than that of the other non-NGCC dispatchable technologies, and we did not propose to identify a new steam EGU implementing full CCS as BSER on that basis. Id. at 1477. The EPA proposed that a standard of performance of 1,100 lb CO_2/MWh-g, reflecting a new steam EGU implementing partial CCS, could be achieved at reasonable cost based on a comparison of the projected LCOE associated with achieving this standard with the alternative dispatchable technologies just mentioned. In the January 2014 proposal, the EPA used LCOE projections for new fossil fuel-fired EGUs from a series of studies conducted by the DOE NETL. These studies—the ''cost and performance studies''—detail expected costs and performance for a range of technology options both with and without CCS.[247] The EPA used LCOE projections for non-fossil dispatchable generation—specifically nuclear and biomass—from the EIA AEO 2013. See 79 FR 1435.

In addition, the EPA proposed that the costs to implement partial CCS were reasonable because a segment of the industry was already accommodating them. *Id.* at 1478. The EPA also considered anticipated decreases in the cost of CCS technologies, the availability of government tax benefits, loan guarantees, and direct expenditures, and the opportunity to generate income from sale of captured CO_2 for EOR. *Id.* at 1478–80. The EPA noted that the proposed standard was not expected to lead to any significant overall costs or effects on electricity prices. *Id.* at 1480–81. The EPA also acknowledged the overall market context, noting that fossil steam EGUs, even without any type of CCS, are significantly more expensive than new natural gas-fired electricity generation, but that some electricity suppliers might include new coal-fired generating sources in their generation portfolio, and would pay a premium to do so. *Id.* at 1478.

2. Brief Summary of Cost Considerations Under CAA Section 111

As explained above, CAA section 111(a) directs the EPA to ''tak[e] into account the cost'' of achieving reductions in determining if a particular system of emission reduction is the best that is adequately demonstrated. The statute does not provide further guidance on how costs should be considered, thus affording the EPA considerable discretion in choosing a means of cost consideration. In addition, it should be noted that in evaluating the reasonableness of costs, the D.C. Circuit has upheld application of a variety of metrics, such as the amount of control costs or product price increases. See Section III.H.3.(b).(1) above.

Following the directive of CAA section 111(a) and applicable precedent, the EPA evaluated relevant metrics and context in considering the reasonableness of the regulation's costs. The EPA's findings demonstrate that the costs of the selected final standard are reasonable.

3. Current Context

The EIA projects that few new coal-fired EGUs will be constructed over the coming decade and that those that are built will apply CCS, reflecting the broad consensus of government, academic, and industry forecasters.[248]

[247] For the cost estimates in the January 2014 proposal, the EPA used costs for new SCPC and IGCC units utilizing bituminous coal from the reports ''Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity'', Revision 2, Report DOE/NETL–2010/1397 (November 2010) and ''Cost and Performance of PC and IGCC Plants for a Range of Carbon Dioxide Capture'', DOE/NETL–2011/1498, May 27, 2011. Additional cost and performance information can be found in additional volumes that are available at *http://www.netl.doe.gov/research/energy-analysis/energy-baseline-studies.*

[248] Even in its sensitivity analysis that assumes higher natural gas prices and electricity demand, EIA does not project any additional coal beyond its

The primary reasons for this projected trend include low electricity demand growth, highly competitive natural gas prices, and increases in the supply of renewable energy. In particular, U.S. electricity demand growth has followed a downward sloping trend for decades with future growth expected to remain very low.[249] Furthermore, the EPA projects that, for any new fossil fuel-fired electricity generating capacity that is constructed through 2030, natural gas will be the overwhelming fuel of choice.[250] See RIA chapter 4.

The EIA's projection is confirmed by an examination of Integrated Resource Plans (IRPs) contained in a TSD in the docket for this rulemaking. IRPs are used by utilities to plan operations and investments in both owned generation and power purchase agreements over long time horizons. Though IRPs do not demonstrate a utility's intent to pursue a particular generation technology, they do indicate the types of new generating technologies that a utility would consider for new generating capacity. The EPA's survey of recent IRPs demonstrates that across the nation, utilities are not actively considering constructing new coal-fired generation without CCS in the near term.

Accordingly, construction of new uncontrolled coal-fired generating capacity is not anticipated in the near term, even in the absence of the standards of performance we are finalizing in this rule, except perhaps in certain limited circumstances.

In particular, commenters suggested that some developers might choose to build a new coal-fired EGU, despite its not being cost competitive, in order to achieve or maintain ''fuel diversity.'' Fuel diversity could provide important value by serving as a hedge against the possibility that future natural gas prices will far exceed projected levels.

Public announcements, including IRPs, confirm that utilities are interested in technologies that could provide or preserve fuel diversity within generating fleets. The Integrated Resource Plan TSD [251] notes examples where the goal of fuel diversity was considered in IRPs; in many cases, these plans considered new generation that would not rely on natural gas. In particular, several utilities that considered fuel diversity in developing their IRPs included new nuclear generation as a potential future generation strategy.

In addition, the EPA recognizes that there may be interest in constructing a new combined-purpose coal-fired facility that would generate power as well as produce chemicals or CO_2 for use in EOR projects. These facilities would similarly provide additional value due to the revenue streams from saleable chemical products or CO_2.[252]

As demonstrated below, the agency carefully considered the reasonableness of costs in identifying a standard that allows a path forward for such projects and rejects more stringent options that would impose potentially excessive costs. In fact, based on this careful consideration of costs, the EPA is finalizing a substantially lower cost standard than the one we proposed. At the same time, we note the unusual circumstances presented here, where the record, and indeed simple consideration of electricity market economics, demonstrates that non-economic factors such as fuel diversity are likely to drive any construction of new coal-fired generation. See also RIA chapter 4 (documenting that electric power companies will choose to build new EGUs that comply with the regulatory requirements of this rule even in its absence, primarily NGCC units, because of existing and expected market conditions). Under these circumstances, the EPA's consideration of costs takes into account that higher costs can be viewed as reasonable when costs are not a paramount factor in new coal capacity decisions. At the same time, the EPA acknowledges and agrees with the public comments that such an argument, left unconstrained, could justify any standard and obviate all cost considerations.[253] The EPA has reasonably cabined its consideration of costs by examining costs for comparable non-NGCC base load dispatchable technologies, as well as by considering capital costs and other cost metrics.[254] This cost-reasonable standard will preserve the opportunity for such projects while driving new technology deployment.[255]

4. Consideration of Capital Costs

As noted above, CAA section 111 does not mandate any particular method for evaluating costs, leaving the EPA with significant discretion as to how to do so. One method is to consider the incremental capital costs required for a unit to achieve the standard of performance.

The EPA included information on capital cost at proposal and, as discussed further below, the LCOE metric relied upon at proposal and in this final rulemaking incorporates and fully reflects capital costs.[256] Nonetheless, extensive comment from industry representatives and others noted persuasively that fossil-steam units are very capital-intensive projects and recommended that a separate metric, solely of capital costs, be considered by the EPA in evaluating the final standard's costs. Accordingly, the EPA has considered the final standard's impact on the capital costs of new fossil-steam generation. The EPA has determined that the incremental capital costs of the final standard are reasonable because they are comparable to those in prior regulations and to industry experience, and because the fossil steam electric power industry has been shown to be able to successfully absorb capital costs of this magnitude in the past.

Prior new source performance standards for new fossil steam generation units have had significant—yet manageable—impacts on the capital costs of construction. The EPA estimated that the costs for the 1971 NSPS for coal-fired EGUs were $19M for a 600 MW plant, consisting of $3.6M for particulate matter controls, $14.4M for sulfur dioxide controls, and $1M for nitrogen oxides controls, representing a 15.8 percent increase in capital costs

reference case until 2023, in a case where power companies assume no GHGs emission limitations, and until 2024 in a case where power companies do assume GHGs emission limitations. EIA, ''Annual Energy Outlook 2015,'' DOE/EIA–0383(2015), April 2015, ''[v]ery little unplanned coal-fired capacity is added across all the AEO 2015 cases'', p. 26.

[249] EIA, ''Annual Energy Outlook 2015,'' DOE/EIA–0383(2015), April 2015, p. 8.

[250] Integrated Planning Model (IPM) run by the EPA (v. 5.15) Base Case, available at *www.epa.gov/airmarkets/powersectormodeling.html*.

[251] Technical Support Document—''Review of Electric Utility Integrated Resource Plans'' (May 2015), available in the rulemaking docket EPA–HQ–OAR–2013–0495.

[252] The EPA may, of course, consider revenues generated as a result of application of pollution control measures in assessing the costs of a best system of emission reduction. See *New York* v. *Reilly,* 969 F.2d 1147, 1150–52 (D.C. Cir. 1992).

[253] See, *e.g.,* Comments of Murray Energy, pp. 79–80 (Docket entry: EPA–HQ–OAR–2013–0495–10046).

[254] Indeed, the EPA is not only adopting a standard predicated on a lower rate of carbon capture than proposed, but also rejecting full CCS for reasons of cost. See Section V.P below. Thus, although the EPA has reasonably taken into account the current economic posture of the industry whereby new capacity is not cost-competitive and so would be added for non-economic reasons, it is not using that fact to negate consideration of cost here. See also Section V.I.4 below responding to comments that the incremental cost of partial CCS could prove the difference between constructing and not constructing new coal capacity.

[255] In this rulemaking, our determination that the costs are reasonable means that the costs meet the cost standard in the case law no matter how that standard is articulated, that is, whether the cost standard is articulated through the terms that the case law uses, *e.g.,* ''exorbitant,'' ''excessive,'' etc., or through the term we use for convenience, ''reasonableness.''

[256] See RIA chapter 4.5.4 and Fig. 4–3; see also ''Cost and Performance Baseline for Fossil Energy Plants Supplement: Sensitivity to CO_2 Capture Rate in Coal-Fired Power Plants'', DOE/NETL–2015/1720 (July 2015) p. 17.

above the $120M 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.

In reviewing the 1978 NSPS for coal-fired EGUs, the D.C. Circuit recognized that ''EPA estimates that utilities will have to spend tens of billions of dollars by 1995 on pollution control under the new NSPS'' and that ''[c]onsumers will ultimately bear these costs.'' *Sierra Club,* 657 F.2d at 314. The court nonetheless upheld the EPA's determination that the standard was reasonable. *Id.* at 410.

The cost and investment impacts of the 1978 NSPS on electric utilities were subsequently evaluated in a 1982 Congressional Budget Office (CBO) retrospective study.[257] The CBO study highlighted that installation of scrubbers—capital intensive pollution control equipment that had ''in effect'' been mandated by the 1978 NSPS—increased capital costs for new EGUs by 10 to as much as 20 percent.[258] The study further noted that air pollution control requirements in general had led to an estimated 37.5 to 45 percent increase in capital costs for coal-fired power plant installation between 1971 and 1980.[259]

The study retrospectively confirmed the EPA's conclusion that imposition of these costs was reasonable, finding that ''utilities with commitments to pollution control tend to fare no better and no worse than all electric utilities in general.'' [260] In assessing the capital cost impacts of the suite of 1970s EPA air pollution standards, the report concluded that ''though controlling emissions is indeed costly, it has not played a major role in impairing the utilities' financial position, and is not likely to do so in the future.'' [261]

In NSPS standards for other sectors, the EPA's determination that capital cost increases were reasonable has similarly been upheld. 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).

The capital cost impacts incurred under these prior standards are comparable in magnitude on an individual unit basis to those projected for the present standard. We predict that the incremental costs of control for a new highly efficient SCPC unit to meet the final emission limitation of 1,400 lb CO_2/MWh-g would be an increase of 21–22 percent for capital costs. See Table 7 below.[262 263]

TABLE 7—COMPARISON OF ESTIMATED CAPITAL COSTS FOR A NEW SCPC AND A NEW SCPC MEETING THE FINAL STANDARD OF PERFORMANCE [264]

	Total overnight cost (2011$/kW)	Total as-spent capital (2011$/kW)
SCPC—no CCS	2,507	2,842
SCPC—partial CCS (1,400 lb CO_2/MWh-g)	3,042	3,458
Incremental cost increase	21.3%	21.7%

By comparison, a SCPC that co-fires with natural gas to meet the final standard of 1,400 lb CO_2/MWh-g would not result in an increase in capital cost over the uncontrolled SCPC. A compliant IGCC unit co-firing natural gas is predicted to have Total Overnight Cost of $3,036/kW—an approximately 21.1 percent increase in capital over the uncontrolled SCPC unit.

5. Consideration of Costs Based on Levelized Cost of Electricity

As in the proposal, the EPA also considered the reasonableness of costs by evaluating the LCOE associated with the final standard. The LCOE is a commonly used economic metric that takes into account all costs to construct and operate a new power plant over an assumed time period and an assumed capacity factor. The LCOE is a summary metric, which expresses the full cost of generating electricity on a per unit basis (*i.e.,* megawatt-hours). Levelized costs are often used to compare the cost of different potential generating sources. While capital cost is a useful and relevant metric for capital-intensive fossil-steam units, the LCOE can serve as a useful complement because it takes into account all specified costs (operation and maintenance, fuel—as well as capital costs), over the whole lifetime of the project.

As previously mentioned, at proposal the EPA relied on LCOE projections for fossil fuel-fired EGUs (with and without CCS) from DOE/NETL reports detailing the results of studies evaluating the costs and performance of such units. For non-fossil dispatchable generating sources, the EPA relied on LCOE projections from EIA AEO 2013. For this final action, the EPA is relying on updated costs from the same sources. The NETL has provided updated cost and performance information in recently published revisions of reports used in the January 2014 proposal.[265] The updated SCPC cases in the reports include up-to-date cost and performance information from recent vendor quotes

[257] Congressional Budget Office report, ''The Clean Air Act, the Electric Utilities, and the Coal Market'', April 1982, p. 10–11, 23.

[258] *Id.* at 10–11.

[259] *Id.* at 22.

[260] *Id.* at xvi.

[261] *Id.*

[262] We explain at Section V.I.2 and 3 below the reasonableness of the EPA's cost projections here.

[263] We estimate that a new SCPC EGU using low rank coal (subbituminous coal or dried lignite) would incur a capital cost increase of 23 percent to meet the final standard. See ''Achievability of the Standard for Newly Constructed Steam Generating EGUs'' technical support document available in the rulemaking docket.

[264] Exhibit A–3 (p. 18); ''Cost and Performance Baseline for Fossil Energy Plants Supplement: Sensitivity to CO_2 Capture Rate in Coal-Fired Power Plants'', DOE/NETL–2015/1720 (June 2015).

[265] ''Cost and Performance Baseline for Fossil Energy Plants: Volume 1a'' Bituminous Coal (PC) and Natural Gas to Electricity, Revision 3, U.S. DOE NETL report (2015) and ''Cost and Performance Baseline for Fossil Energy Plants: Volume 1b: Bituminous Coal (IGCC) to Electricity, Revision 2—Year Dollar Update, U.S. DOE NETL report (2015). Both reports are available at *www.netl.doe.gov/research/energy-analysis/energy-baseline-studies.*

and implementation of the Shell Cansolv post-combustion capture process—the process that is currently being utilized at the Boundary Dam #3 facility. The IGCC cost and performance results in the updated reports utilize vendor quotes from the previous report; the costs are adjusted from $2007 to $2011. Important also to note is that DOE/NETL utilized conventional financing for cases without CCS and utilized high-risk financial assumptions for cases that include CCS.[266]

Using information from those reports, the DOE/NETL prepared a separate report summarizing a study that evaluated the cost and performance of various plants designed to meet a range of CO_2 emissions by varying the CO_2 capture rate (*i.e.,* the level of partial capture).[267] The EIA also updated LCOE projections from AEO 2013 to AEO 2014 and again in AEO 2015. Those are discussed in more detail in Section V.I.2.b and d. In evaluating costs for the final standards in this action, the EPA relied primarily on the updated NETL LCOE projections for new fossil fuel-fired EGUs provided in the reports described above and on the LCOE projections for non-fossil, dispatchable generating options from the EIA's AEO 2015.[268] Here, the EPA compared the LCOE of the final standard to the LCOE of analogous potential sources of intermediate and base load power. This comparison demonstrated that the LCOE for a fossil steam unit with partial CCS is within the range of the LCOE of comparable alternative non-NGCC generation sources. In particular, nuclear and biomass generation, which similarly provide both base load power and fuel diversity, have comparable LCOE. The EPA concludes that an evaluation of the LCOE also demonstrates that the costs of the final standard are reasonable.

a. Calculation of the LCOE

The LCOE of a power plant source is calculated with the expected lifetime and average capacity factor, and represents the average cost of producing a megawatt-hour (MWh) of electricity over the expected lifetime of the asset.

The LCOE incorporates all specified costs, and therefore is dependent on the project's capital costs, the fixed and variable operating and maintenance (O&M) costs, the fuel costs, the costs to finance the project, and finally on the assumed capacity factor.[269] The relative contribution of each of these inputs to LCOE will vary among the generating technologies. For example, the LCOE for a new supercritical PC plant or a new IGCC plant is influenced more by the capital costs (and thus the financing assumptions) and less on fuel costs than a comparably sized new NGCC facility which would require less capital investment but would be more influenced by assumed fuel costs.

b. Use of the LCOE

The utility industry and electricity sector regulators often use levelized costs as a summary measure for comparing the cost of different potential generating sources. Use of the LCOE as a comparison measure is appropriate where the facilities being compared would serve load in a similar manner.

The value of generation, as reflected in the wholesale electricity price, can vary seasonally and over the course of a day. In addition, electricity generation technologies differ on dimensions other than just cost, such as ramping efficiency, intermittency, or uncertainty in future fuel costs. These other factors are also important in determining the value of a particular generation technology to a firm, and accordingly cost comparisons between two different technologies are most appropriate and insightful when the technologies align along these other dimensions. Isolating a comparison of technologies based on their LCOE is appropriate when they can be assumed to provide similar services and similar values of electricity generated.

As we indicated in the proposal, we evaluated publicly available IRPs and other available information (such as public announcements) to determine the types of technologies that utilities are considering as options for new generating capacity.[270] In the near future, the largest sources of new fossil fuel-fired power generation are expected to be new NGCC units. But the IRPs also suggested that utilities are interested in a range of technologies that can be used to provide or preserve fuel diversity within the utilities' respective generating fleets.[271] [272] The options for

[266] Cost and Performance Baseline for Fossil Energy Plants Supplement: Sensitivity to CO_2 Capture Rate in Coal-Fired Power Plants'', DOE/NETL–2015/1720 (June 2015) p. 18.

[267] ''Cost and Performance Baseline for Fossil Energy Plants Supplement: Sensitivity to CO_2 Capture Rate in Coal-Fired Power Plants'', DOE/NETL–2015/1720 (June 2015). Available at *http://www.netl.doe.gov/research/energy-analysis/energy-baseline-studies.*

[268] *http://www.eia.gov/forecasts/aeo/electricity_generation.cfm.*

[269] See, *e.g.* ''Cost and Performance Baseline for Fossil Energy Plants Supplement: Sensitivity to CO_2 Capture Rate in Coal-Fired Power Plants'', DOE/NETL–2015/1720 (June 2015) at p. 17.

[270] See also discussion at V.C.3 above. The IRPs do not provide an indication of the utility's intention to pursue a particular generation technology. However, the IRPs do provide an indication of the types of new generating technologies that the utility would consider for new generating capacity.

[271] See, *e.g.* the 2014 IRP of Dominion Virginia Power:

With those factors in mind, the 2014 Plan presents two paths forward for resource expansion: a Base Plan, designed using least-cost planning methods and consistent with the requirements of Rule R8–60 for utility plans to provide ''reliable electric utility service at least cost over the planning period;'' and a Fuel Diversity Plan, which includes a broader array of low or zero-emissions options. While the Fuel 2 Diversity Plan currently represents a higher cost option at today's current and projected commodity prices, its resource mix provides the important benefits of greater fuel diversity and lower carbon intensity. Therefore, the Company will continue reasonable development of the more diverse and lower carbon intensive options in the Fuel Diversity Plan and will be ready to implement them as conditions warrant. . . . The Fuel Diversity Plan places a greater reliance on generation sources with little or no carbon emissions and is less reliant on natural gas. While following the resource expansion scenario in the least-cost Base Plan, the Company will continue evaluation and reasonable development efforts for the following projects identified in the Fuel Diversity Plan. These include:

Continued development of a third nuclear reactor at North Anna Power Station, using reactor technology supplied by GE-Hitachi Nuclear Energy Americas LLC. While the Company has made no final commitment to building this unit, it recognizes the many operational and environmental benefits of nuclear power and continues to actively develop the project. Our customers have benefitted from the existing nuclear fleet for many years now, and they will continue to benefit from the existing fleet for many years in the future. A final decision on construction of North Anna Unit 3 will not be made until after the Company receives a Combined Operating License or COL from the U.S. Nuclear Regulatory Commission, now expected in 2016. The Fuel Diversity Plan includes the addition of North Anna Unit 3's 1,453 megawatts of zero-emissions generation by 2028. If constructed, the project would provide a dramatic boost to the regional economy.

Additional reliance on renewable energy, including 247 megawatts of onshore wind capacity at sites in western Virginia and a 12 megawatt offshore wind demonstration project by 2018.

An additional 559 megawatts of nameplate solar capacity, including several new Company-owned photovoltaic CPV) installations. Solar PV costs have declined significantly in recent years, making utility-scale solar much more cost-effective than distributed solar, and continuing technological development, in which the Company is participating, may allow it to become a more cost-effective source of intermittent generation in the future.cover letter for 2014 IRP—*https://www.dom.com/library/domcom/pdfs/corporate/integrated-resource-planning/va-irp-2014.pdf.*

[272] Another example are the recent statements of officials of Tri-State Generation and Transmission, available at *http://www.wyofile.com/coal-power/*, including:

''We are considering nuclear, coal and natural gas,'' said Ken Anderson, general manager of Tri-State at a conference in October [2010], a position that Tri-State representatives say remains. ''We will pick our technology once policy certainty comes about,'' he added. . . . Longer-term forecasts are based on assumptions that may or may not prove well-founded. Because of this uncertainty, Tri-State believes it must retain options for all fuels and technologies.

''We will not take anything off the table,'' [Tri-State spokesman Lee] Boughey said. That includes coal. ''Coal is an affordable and plentiful resource, but it does come with challenges—and we are

Continued

dispatchable generation that can provide intermediate or base-load power and fuel diversity would include new fossil steam units, new nuclear power, and biomass-fired generation.

Thus, in both the proposal and in this final rule, the EPA is comparing the LCOE of technologies that would be reasonably anticipated to be designed, constructed, and operated for a similar purpose—that is, to provide dispatchable base load power that provides fuel diversity by relying on a fuel source other than natural gas. In contrast, it may not be appropriate to compare the LCOE for a base load coal-fired plant with that of a peaking natural gas-fired simple cycle turbine. Similarly, it may not be appropriate to compare LCOE for dispatchable technologies (*i.e.,* generating sources that can be ramped up or down as needed, *e.g.,* coal-fired units, NGCC units, nuclear) with that of non-dispatchable technologies (*i.e.,* generating sources that cannot be reliably ramped up or down to meet demand, *e.g.,* wind, solar.)

c. Reasonableness of Costs Based on LCOE

An examination of the LCOE of analogous sources of base load, dispatchable power shows that the final standard's LCOE is comparable to that of other sources, as shown in Table 8 below. As mentioned earlier and discussed in further detail below, these estimates rely most heavily on DOE/NETL cost projections for fossil fuel generating technologies and on the updated EIA AEO 2015 for non-fossil generation technologies. Recent estimates from Lazard [273] [274] are also provided for nuclear and biomass generation options.

TABLE 8—PREDICTED COST AND CO_2 EMISSION LEVELS FOR A RANGE OF POTENTIAL NEW GENERATION TECHNOLOGIES [275]

New generation technology	Emission lb CO_2/MWh-g	LCOE* $/MWh
SCPC—no CCS (bit)	1,620	76–95
SCPC—no CCS (low rank)	1,740	75–94
SCPC + ~16% partial CCS (bit)	1,400	92–117
SCPC + ~23% partial CCS (low rank)	1,400	95–121
Nuclear (EIA)	0	87–115
Nuclear (Lazard)	0	92–132
Biomass (EIA) [276]	—	94–113
Biomass (Lazard)	—	87–116
IGCC	1,430	94–120
NGCC	1,000	** 52–86

* The LCOE ranges presented in Table 8 include an uncertainty of −15%/+30% on capital costs for SCPC and IGCC cases and an uncertainty of −10%/+30% on capital costs for nuclear and biomass cases from EIA. This reflects information provided by EIA. Nuclear staff experts expect that nuclear plants currently under construction would not have capital costs under estimates and that one could expect to see a 30% "upside" variation in capital cost. There is also insufficient market data to get a good statistical range of potential capital cost variation (*i.e.* only 2 plants under construction, neither complete). The nuclear cost estimates from Lazard likewise reflect the range of expected nuclear costs. LCOE estimates displayed in this table for SCPC units with partial CCS as well as for IGCC units use a higher financing cost rate in comparison to the SCPC unit without capture.[277]

** This range represents a natural gas price from $5/MMBtu to $10/MMBtu.

As shown in Table 8, we project that the LCOE for new fossil steam capacity meeting the final 1,400 lb CO_2/MWh-g standard to be substantially similar to that for a new nuclear unit, the principal other alternative to natural gas to provide new base load power. This is the case for new units firing bituminous and subbituminous coals and dried lignite. This is another demonstration that the costs of the final standard are reasonable because nuclear and fossil steam generation each would serve an analogous role in adding dispatchable base load generation diversity—or at least non-NGCC alternatives—to a power provider's portfolio; hence, they are reasonably viewed as comparable alternatives.[278]

As previously mentioned, the DOE/NETL assumed conventional financing

looking to different technology that can address some of those challenges while continuing to provide a reliable and affordable power supply,'' Boughey said. ''Some critics believe we shouldn't be looking at resource options that include coal, and even nuclear technology,'' Boughey added. ''We believe it would be irresponsible not to consider these fuels or technologies as part of an affordable, reliable and responsible resource portfolio.''

[273] Lazard's Levelized Cost of Energy Analysis—Version 8.0; September 2014; available at: *http://www.lazard.com/media/1777/levelized_cost_of_energy_-_version_80.pdf* and in the rulemaking docket.

[274] Lazard is one of the world's preeminent financial advisory and asset management firms. Lazard's Global Power, Energy & Infrastructure Group serves private and public sector clients with advisory services regarding M&A, financing, and other strategic matters. The group is active in all areas of the traditional and alternative energy industries, including regulated utilities, independent power producers, advanced transportation technologies, renewable energy technologies, meters, smart grid and energy efficiency technologies, and infrastructure. *http://www.marketwatch.com/story/lazard-releases-new-levelized-cost-of-energy-analysis-2014-09-18.*

[275] LCOE cost estimates for SCPC and IGCC cases come from ''Cost and Performance Baseline for Fossil Energy Plants Supplement: Sensitivity to CO_2 Capture Rate in Coal-Fired Power Plants'' DOE/NETL–2015/1720 (June 22, 2015). Cost and performance for low rank SCPC is adapted from ''Cost and Performance Baseline for Fossil Energy Plants Volume 3 Executive Summary: Low Rank Coal and Natural Gas to Electricity'', DOE/NETL–2010/1399 (September 2011). LCOE cost estimates for nuclear and biomass are derived from ''Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2015'', June 2015, *www.eia.gov/forecasts/aeo/pdf/electricity_generation.pdf.* LCOE cost estimates for NGCC technology are EPA estimates based on a range of potential natural gas prices.

[276] Table 8 includes LCOE figures for biomass-fired generation, a potential sources of dispatchable base load power that is not fueled by natural gas. The EPA includes this information for completeness, while noting that biomass-fired units in operation in the U.S. are smaller scale and thus are not as robust analogues as nuclear power. CO_2 emissions are not provided for biomass units because different biomass feedstocks have different net CO_2 emissions; therefore a single emission rate is not appropriate to show in Table 8.

[277] ''Cost and Performance Baseline for Fossil Energy Plants Supplement: Sensitivity to CO_2 Capture Rate in Coal-Fired Power Plants'', DOE/NETL–2015/1720 (June 2015) at p. 18.

[278] LCOE comparisons of reasonably available compliance alternatives—IGCC with natural gas co-firing, and SCPC with natural gas co-firing—are found below in Table 9. As shown there, these alternatives are either lower cost than SCPC with partial CCS, or of comparable cost.

for cases without CCS and assumed high-risk financing for cases with some level of CCS. Specifically a high-risk financial structure resulting in a capital charge factor (CCF) of 0.124 is used in the study to evaluate the costs of all cases with CO_2 capture (non-capture case uses a conventional financial structure with a CCF of 0.116).[279] As a comparison of how this affects the resulting DOE/NETL costs, a new SCPC utilizing 16 percent partial CCS is projected to have an LCOE of $99/MWh (including transportation and storage costs; does not include the range for uncertainty). That projected LCOE includes the ''high risk financial assumptions''. If the LCOE for that unit were to be calculated using the ''conventional financing assumptions'', the resulting LCOE would be $94/MWh.

This approach is in contrast to that taken by the EIA which applies a 3-percentage-point cost of capital premium (the 'climate uncertainty adder') to non-capture coal plants to reflect the market reaction to potential future GHG regulation.

Under current and anticipated market conditions, power providers that are considering costs alone in choosing a fuel source for new intermediate or base load generation will choose natural gas because of its competitive current and projected price. However, as noted in Section V.H.3, public IRPs indicate that utilities are considering and selecting technologies that could provide or preserve fuel diversity within generating fleets. For example, utilities have been willing to pay a premium for nuclear power in certain circumstances, as indicated by the recent new constructions of nuclear facilities and by IRPs that include new nuclear generation in their plans. In general, fossil steam and nuclear generation each can provide dispatchable, base load power while also maintaining or increasing fuel diversity.[280] Utilities may be willing to pay a premium for these generation sources because they could serve as a hedge against the possibility that future natural gas prices will far exceed projected levels. Accordingly, the LCOE analysis demonstrates that the final standard's costs are in line with power sources that provide analogous services—dispatchable base load power and fuel diversity.

We further note a number of conservative elements of the costs we used in making this comparison. In particular, these estimates include the highest value in the projected range of potential costs for partial CCS. They do not reflect revenues which can be generated by selling captured CO_2 for enhanced oil recovery, and reflect the costs of partial CCS rather than potentially less expensive alternative compliance paths such as a utility boiler co-firing with natural gas. See also V.H.7 and 8 below.

6. Overall Costs and Economic Impacts

As noted above, an assessment of national costs is also an appropriate means of evaluating the reasonableness of costs under CAA section 111. See *Sierra Club,* 657 F.2d at 330.

The EPA considered the regulation's overall costs and economic impacts as part of its RIA. The RIA demonstrates that these costs would be negligible and that the effects on electricity rates and other market indicators would similarly be minimal.

These results are driven by the existing market context for fossil-steam generation. Even in the absence of the standards of performance for newly constructed EGUs, substantial new construction of uncontrolled fossil steam units is not anticipated under existing prevailing and anticipated future economic conditions. Modeling projections from government, industry, and academia anticipate that few new fossil steam EGUs will be constructed over the coming decade and that those that are built would have CCS.[281] Instead, EIA data shows that natural gas is likely to be the most widely-used fossil fuel for new construction of electric generating capacity in the near future.[282] Of the coal-fired units moving forward at various advanced stages of construction and development—Southern Company's Kemper County Energy Facility and Summit Power's Texas Clean Energy Project (TCEP)—each will deploy IGCC with some level of CCS. The primary reasons for this rate of current and projected future development of new coal projects include highly competitive natural gas prices, lower electricity demand, and increases in the supply of renewable energy.

In its RIA, the EPA considered the overall costs of this regulation in the context of these prevailing market trends. Because of the expectation of no new fossil steam generation, the RIA projects that this final rule will result in negligible costs overall on owners and operators of newly constructed EGUs by 2022.[283] More broadly, this regulation is not expected to have significant effects on fuel markets, electricity prices, or the economy as a whole, as described in detail in Chapter 4 of the RIA.

In comparison, courts have upheld past regulations that imposed substantial overall costs in order to protect against uncontrolled emissions. As noted above, in *Sierra Club* v. *Costle,* the D.C. Circuit upheld a standard of performance that imposed costly controls on SO_2 emissions from new coal-fired power plants. 657 F.2d at 410. These standards had implications for the economy ''at the local and national levels,'' as ''EPA estimates that utilities will have to spend tens of billions of dollars by 1995 on pollution control under the new NSPS.'' *Id.* at 314. Further, the court acknowledged that ''[c]onsumers will ultimately bear these costs, both directly in the form of residential utility bills, and indirectly in the form of higher consumer prices due to increased energy costs,'' before concluding that the costs were reasonable. *Id.*

The projected total incremental capital costs associated with the standard we are finalizing in this rule are dramatically lower than was the case for this prior standard, as well as other prior standards summarized previously. For example, when the standard at issue in *Sierra Club* was upheld, the industry was expected to build, and did build, dozens of plants ultimately meeting the standards—at a projected incremental cost of tens of billions of dollars.[284] Here, by contrast, few if any fossil steam EGUs are projected to be built in the foreseeable future, indicating that the total incremental costs are likely to be considerably more modest.

Commenters stated that the cost provision in CAA section 111(a)(1) does not authorize the EPA to consider the nationwide costs of a system of emission reduction in lieu of considering the cost impacts for individual new plants. In this rule, we

[279] ''Cost and Performance Baseline for Fossil Energy Plants Supplement: Sensitivity to CO_2 Capture Rate in Coal-Fired Power Plants'', DOE/NETL–2015/1720 (June 2015) at p. 7.

[280] As another example, San Antonio customers will benefit from low-carbon power from the Texas Clean Energy Project. CPS Energy CEO Doyle Deneby said in a news release: ''*Adding clean coal to our portfolio dovetails with our strategy to diversify and reduce the carbon intensity of the power we supply to our customers.*'' *www.bizjournals.com/sanantonio/news/2014/10/06/cps-energy-strikes-new-deal-to-buy-power-from.html.*

[281] RIA chapter 4. For example, even in the EIA's sensitivity analysis that assumes higher natural gas prices and electricity demand, the EIA does not project any additional coal beyond its reference case until 2023, in a case where power companies assume no GHGs emission limitations, and until 2024 in a case where power companies do assume GHGs emission limitations. AEO 2015.

[282] Annual Energy Outlook 2010, 2011, 2012, 2013, 2014 and 2015.

[283] Conditions in the analysis year of 2022 are represented by a model year of 2020.

[284] *Sierra Club,* 657 F.2d at 314.

are considering both sets of costs and, in fact, we are not identifying full CCS as the BSER primarily for reasons of its cost to individual sources. At the same time, total projected costs are relevant in assessing the overall reasonableness of costs associated with a standard. Our analysis demonstrates that the impacts on the industry as a whole are negligible, and are certainly not greater than ''what the industry could bear and survive.'' [285] These facts support the EPA's overall conclusion that the costs of the standard are reasonable.

However, as noted earlier, for a variety of reasons, some companies may consider coal-fired steam generating units that the modeling does not anticipate. Thus, in Chapter 5 of the RIA, we also present an analysis of the project-level costs of a newly constructed coal-fired steam generating unit with partial CCS that meets the requirements of this final rule alongside the project-level costs of a newly constructed coal-fired unit without CCS. This analysis in RIA chapter 5 indicates that the quantified benefits of the standards of performance would exceed their costs under a range of assumptions.

As required under Executive Order 12866, the EPA conducts benefit-cost analyses for major Clean Air Act rules, and has done so here. While such analysis can help to inform policy decisions, as permissible and appropriate under governing statutory provisions, the EPA does not use a benefit-cost test (*i.e.,* a determination of whether monetized benefits exceed costs) as the sole or primary decision tool when required to consider costs or to determine whether to issue regulations under the Clean Air Act, and is not doing so here.[286] Nonetheless, as just noted, the RIA analysis shows that the standard of performance has net quantified benefits under a range of assumptions.

7. Opportunities to Further Reduce Compliance Costs

While the EPA believes, as detailed above, that there is sufficient evidence to show that the final standards of performance for new steam generating units can be met at a reasonable cost, we also note that there are potential opportunities to further reduce compliance costs. We believe that, in most cases, the actual costs will be less than those presented earlier.

As explained in more detail in the following subsection, a new utility boiler can meet the final standard of performance by co-firing with natural gas. Some project developers may choose to utilize natural gas co-firing as a means of delaying, rather than avoiding, implementation of partial CCS. Developers can also choose to install IGCC with a small amount of natural gas co-firing at costs within the range of SCPC with partial CCS, although slightly higher.

The EPA also notes that new units that capture CO_2 will likely be built in areas where there are opportunities to sell the captured CO_2 for some useful purpose prior to (or concomitant with) permanent storage. The DOE refers to this as ''carbon capture, utilization and storage'' or CCUS. In particular, the ability to sell captured CO_2 for use in enhanced oil recovery operations offers the most opportunity to reduce costs. In this regard, the newly-operating Boundary Dam facility is selling captured CO_2 for EOR. The Kemper facility likewise plans to do so.[287]

In some instances, the costs of CCS may be defrayed by grants or other benefits provided by federal or state governments. The need for subsidies to support emerging energy systems and new control technologies is not unusual. Each of the major types of energy used to generate electricity has been or is currently being supported by some type of government subsidy such as tax benefits, loan guarantees, low-cost leases, or direct expenditures for some aspect of development and utilization, ranging from exploration to control installation. This is true for fossil fuel-fired, as well as nuclear-, geothermal-, wind-, and solar-generated electricity. As stated earlier, the EPA considers the costs of partial CCS at a level to meet the final standard of performance to be reasonable even without considering these opportunities to further reduce implementation and compliance costs. We did not in the proposal—and we do not here in this final action—rely on any cost reduction opportunities to justify the costs of meeting the standard as reasonable, but again note the conservative assumptions embodied in our assessment of compliance costs.

a. Cost and Feasibility of Natural Gas Co-firing as an Alternative Compliance Pathway

Although the EPA has determined that implementation of partial CCS at an emission limitation of 1,400 lb CO_2/MWh-g is the BSER for newly constructed fossil fuel-fired steam generating EGUs, we also note that operators can consider the use of natural gas co-firing to achieve the final emission limitation, likely at a lower cost.

At the final emissions limitation of 1,400 lb CO_2/MWh-g a new supercritical PC or supercritical CFB can meet the standard by co-firing with natural gas at levels up to approximately 40 percent (heat input basis) and could potentially avoid (or delay) installation and use of partial CCS altogether.

Natural gas co-firing has long been recognized as an option for coal-fired boilers to reduce emissions of criteria and hazardous air pollutants. EPRI sponsored a study to assess both technical and economic issues associated with natural gas co-firing in coal-fired boilers.[288] They determined that the largest number of applications and the longest experience time is with natural gas reburning and with supplemental gas firing. Natural gas reburning has been used primarily as a NO_X control technology. It is implemented by introducing natural gas (up to 20 percent total fuel heat input) in a secondary combustion zone (called the ''reburn zone'') downstream of the primary combustion zone in the boiler. Injecting the natural gas creates a fuel-rich zone where NO_X formed in the main combustion zone is reduced to nitrogen and water vapor.

Higher levels of natural gas co-firing can be met by utilizing supplemental gas co-firing (either alone or along with natural gas reburning). This involves the simultaneous firing of natural gas and pulverized coal in a boiler's primary combustion zone. Others have also evaluated configurations that would allow coal-fired units to utilize natural gas.[289] [290]

[285] *Portland Cement Ass'n,* 513 F.2d at 508.

[286] See Memorandum ''Consideration of Costs and Benefits under the Clean Air Act'' available in the rulemaking dockets, EPA–HQ–OAR–2013–0495 (new sources) and EPA–OAR–HQ–2013–0603 (modified and reconstructed sources).

[287] The EPA is referring to the Kemper facility here as an example of how costs can be defrayed, not for use of technology or level of emission reduction achieved. The EPA therefore does not believe that the EPAct05 prevents reference to the fact that Kemper plans to sell captured carbon.

[288] Gas Cofiring Assessment for Coal Fired Utility Boilers; Final Report, August 2000; EPRI Technical Report available at *www.epri.com.*

[289] Many of the studies evaluated opportunities to use natural gas reburn, natural gas co-firing and other configurations in existing coal-fired boilers. Those conclusions would also be applicable for new coal-fired boilers.

[290] ''Dual Fuel Firing—The New Future for the Aging U.S. Based Coal-Fired Boilers'', presented by Riley Power, Inc. at 37th International Technical Conference on Clean Coal and Fuel Systems June 2012 Clearwater, FL, available at *http://www.babcockpower.com/pdf/RPI-TP-0228.pdf.*

A 2013 article entitled ''Utility Options for Leveraging Natural Gas'' [291] noted that:

Utility owners of coal-fired power stations that wish to balance their exposure to coal-fired generation with additional natural gas-fired generation have several options to consider. The four most practical options are co-firing coal and gas in the same boiler, converting the coal-fired boiler to gas-only operation, repowering the coal plant with natural gas-fired combustion turbines, or replacing the coal plant with a combined cycle plant. [. . .] Co-firing is the lowest-risk option for substituting gas use for coal.

The EPA examined compliance costs for a new steam generating unit to meet the final standard of performance using natural gas co-firing and compared those costs to the estimated costs of meeting the final standards using partial CCS. Those costs are provided below in Table 9.

TABLE 9—PREDICTED COSTS TO MEET THE FINAL STANDARD USING NATURAL GAS CO-FIRING [292]

New generation technology	Emission lb CO_2/MWh-g	LCOE $/ MWh
SCPC—no CCS	1,620	82
SCPC + ~16% partial CCS	1,400	99
SCPC + ~34% NG co-fire	1,400	92
IGCC—no CCS	1,434	103
IGCC + ~6% NG co-fire	1,400	105
NGCC*	1,000	60

*The generation cost using NG co-fire and NGCC assume a natural gas price of $6.19/mmBtu.

The EPA thus again notes that the cost assumptions it is making in its BSER determination are conservative. That is, by costing partial CCS as BSER, the EPA may be overestimating actual compliance costs since there exist other less expensive means of meeting the promulgated standard.[293]

Notwithstanding that costs for a SCPC to meet the standard would be lower if it co-fired with natural gas, we have not identified that compliance alternative as BSER because we believe that new coal-fired steam electric generating capacity would be built to provide fuel diversity, and burning substantial amounts of natural gas would be contrary to that objective. In addition, this choice would not promote use of advanced pollution control technology. New IGCC has costs which are comparable to SCPC, as does IGCC with natural gas co-firing,[294] but we are choosing not to identify it as BSER for reasons stated at Sections V.C.2 and V.P: use of IGCC does not advance emission control beyond current levels of performance for sources which may choose to utilize IGCC technology. Nonetheless, use of IGCC remains a viable, demonstrated compliance option to meet the 1,400 lb CO_2/MWh-g standard of performance, and is available at reasonable cost and (as shown at Section V.P below) without significant adverse non-air quality impacts or energy implications.

Costs are Reasonably Expected To Decrease Over Time

The EPA reasonably expects that the costs of CCS will decrease over time as the technology becomes more widely deployed. Although, for the reasons that have been noted, we consider the current costs of CCS to be reasonable, the projected decrease in those costs further supports their reasonableness. The D.C. Circuit case law that authorizes determining the ''best'' available technology on the basis of reasonable future projections supports taking into account projected cost reductions as a way to support the reasonableness of the costs.

We expect the costs of CCS technologies to decrease for several reasons. We expect that significant additional knowledge will be gained from deployment and operation of the new coal-fired generation facilities that are either operating or are nearing completion. These would include the Boundary Dam Unit #3 facility, the Petra Nova WA Parish project, and the Kemper County IGCC facility. The operators of the Boundary Dam Unit #3 are considering construction of additional CCS units and have projected that the next units could be constructed at a cost of at least 30 percent less than that at Unit #3.[295] These savings primarily come from application of lessons learned from the Unit #3 design and construction.

To facilitate the transfer of the technology and to accelerate development of carbon capture technology, SaskPower has created the CCS Global Consortium.[296] This consortium provides SaskPower the opportunity to share the knowledge and experience from the Boundary Dam Unit #3 facility with global energy leaders, technology developers, and project developers. SaskPower, in partnership with Mitsubishi and Hitachi, is also helping to advance CCS knowledge and technology development through the creation of the Shand Carbon Capture Test Facility (CCTF).[297] The test facility will provide technology developers with an opportunity to test new and emerging carbon capture systems for controlling carbon emissions from coal-fired power plants.

The DOE also sponsors testing at the National Carbon Capture Center (NCCC). The NCCC—located at Southern Company's Plant Gaston in Wilsonville, AL—provides first-class facilities to test new capture technologies for extended periods under commercially representative conditions with coal-derived flue gas and syngas.[298]

[291] Utility Options for Leveraging Natural Gas, 10/01/2013 article in *Power.* Available at *http://www.powermag.com/utility-options-for-leveraging-natural-gas/.*

[292] Costs and emissions for cases that do not utilize natural gas co-firing are from ''Cost and Performance Baseline for Fossil Energy Plants Supplement: Sensitivity to CO_2 Capture Rate in Coal-Fired Power Plants'', DOE/NETL–2015/1720 (June 2015). Costs and emissions for natural gas co-fired cases are EPA estimates.

[293] Certain commenters argued that the proposed standard essentially mandated a sole method of compliance, and hence constituted a work practice for purposes of section 111(h) of the Act. These commenters argued further that the EPA had failed to justify the proposal under the section 111(h) criteria. The EPA disagrees with the premise of these comments, but, in any case, there are clearly multiple compliance paths available for achieving the final standard.

[294] IGCC units already have combined cycle capacity, and so can be readily operated in whole or in part using natural gas as a fuel. Indeed, both the Edwardsport and Kemper IGCC facilities have operated at times by firing exclusively natural gas.

[295] ''Boundary Dam—The Future is Here'', plenary presentation by Mike Monea at the 12th International Conference on Greenhouse Gas Technologies (GHGT–12), Austin, TX (October 2014).

[296] *http://www.saskpowerccs.com/consortium/.*

[297] *www.saskpowerccs.com/ccs-projects/shand-carbon-capture-test-facility/.*

[298] *www.nationalcarboncapturecenter.com/index.html.*

We expect continued additional cost reductions to come from knowledge gained from continued operation of non-power sector industrial projects which, as we have discussed, are informative in transferring the technology to power sector applications. We expect the on-going research and development efforts—such as those sponsored by the DOE/NETL.

Significant reductions in the cost of CO_2 capture would be consistent with overall experience with the cost of pollution control technology. Reductions in the cost of air pollution control technologies as a result of learning-by-doing, reductions in financial premiums related to risk, research and development investments, and other factors have been observed over the decades.

c. Opportunities To Reduce Cost Through Sales of Captured CO_2

Geologic storage options include use of CO_2 in EOR operations, which is the injection of fluids into a reservoir after production yields have decreased from primary production in order to increase oil production efficiency. CO_2-EOR has been successfully used for decades at many production fields throughout the U.S. to increase oil recovery. The use of CO_2 for EOR can significantly lower the net cost of implementing CCS. The opportunity to sell the captured CO_2 for EOR, rather than paying directly for its long-term storage, improves the overall economics of the new generating unit. According to the International Energy Agency (IEA), of the CCS projects under construction or at an advanced stage of planning, 70 percent intend to use captured CO_2 to improve recovery of oil in mature fields.[299] See also Section V.M.3 below.

I. Key Comments Regarding the EPA's Consideration of Costs

In its consideration of the costs associated with the final standard, the EPA considered a range of different cost metrics, each with its individual strengths and weaknesses. As discussed above, each metric supports the EPA's conclusion that the costs of the final standard are reasonable.

In this section, we review the comments received on assessing cost reasonableness and specific cost metrics. We explain how these comments informed our consideration of different metrics and cost reasonableness in general.

1. Use of LCOE as a Cost Metric

As noted, CAA section 111(a) directs the EPA to consider ''cost'' in determining if the BSER is adequately demonstrated. It does not provide further guidance as to how costs are to be considered, thus affording the EPA considerable discretion to choose a reasonable means of cost consideration. See, *e.g. Lignite Energy Council* v. *EPA,* 198 F. 3d at 933. Certain commenters nonetheless argued that LCOE was an impermissible metric because it does not measure the cost of achieving the emission reduction, but rather measures the impact on the product produced by the entity subject to the standard.[300] The EPA does not agree that its authority is so limited. Indeed, in the first decided case under section 111, the D.C. Circuit, in holding that the EPA's consideration of costs was reasonable, specifically noted the EPA's examination of the impact of the standards on the regulated source category's product in comparison to competitive products. *Portland Cement Ass'n* v. *EPA,* 486 F. 2d at 388 (''costs of control equipment could be passed on without substantially affecting competition with construction substitutes such as steel, asphalt, and aluminum'').

Commenters also argued that the choice of LCOE as a cost metric masked consideration of the considerable capital costs associated with CCS. The EPA disagrees with this contention. The LCOE does not mask consideration of capital costs. Rather, as explained at V.H.5 above, LCOE is a summary metric that expresses the full cost (*e.g.,* capital, O&M, fuel) of generating electricity and therefore provides a useful summary metric of costs per unit of production (*i.e.,* megawatt-hours). Provided that those megawatt-hours provide similar electricity services and align on dimensions other than just cost, then the LCOE provides a useful comparison of which technologies are least cost.

The EPA certainly does not minimize that project developers must take capital costs into consideration, and as discussed in Section V.H.4 above, the EPA accordingly has considered direct capital costs here as part of its assessment and found those costs to be reasonable. In addition, the EPA notes that its comparison of the marginal impacts from an individual illustrative facility's compliance with the standard, discussed in detail above and in the RIA Chapter 5, took into account the marginal capital costs that would be incurred by an individual facility.

According to EIA,[301] capital costs represent approximately 63 percent of the LCOE for a new coal-fired SCPC plant; approximately 66 percent of the LCOE for a new IGCC plant; approximately 74 percent of the LCOE for a new nuclear plant; and only about 22 percent of the LCOE for a new NGCC unit. The LCOE of a new NGCC unit is much more strongly affected by fuel costs (natural gas). As we have discussed in detail in this preamble, in the preamble for the January 2014 proposal, and in associated technical support documents, the power sector has moved toward increased use of natural gas for a variety of reasons. If capital was the only cost that utilities and project developers considered, then they would almost certainly always choose to build a new NGCC unit. However, a variety of factors can be involved in selecting a generation source beyond capital costs. Accordingly, in considering cost reasonableness the EPA considered metrics that encompassed other costs as well as the value of fuel and fleet diversity.

Some commenters maintained that even if LCOE was a proper cost metric, the comparison with the costs of a new nuclear power plant is improper because nuclear itself is a highly expensive technology. The EPA disagrees. The comparison is appropriate and valid because, as discussed at V.H.3 above, under current and foreseeable economic conditions affecting the cost of new fossil steam generation and new nuclear generation relative to the cost of new natural gas generation, neither new nuclear power nor fossil steam generation are competitive with new natural gas if evaluated on the basis of LCOE alone. Nonetheless, both are important potential alternatives to natural gas power for those interested in dispatchable base load power that maintains or increases fuel diversity. As shown in a survey of recent IRP filings in the docket[302] and Section II.C.5 above, several utilities are considering new nuclear power as a potential generation option. Because both fossil steam and nuclear generation serve a comparable role of offering a diverse source of base load power generation, the EPA concludes that the comparison of their LCOE is a valid approach to evaluating cost reasonableness.

[299] Tracking Clean Energy Progress 2013, International Energy Agency (IEA), Input to the Clean Energy Ministerial, OECD/IEA 2013.

[300] Comments of EEI, pp 94–5 (Docket entry: EPA–HQ–OAR–2013–0495–9780).

[301] *http://www.eia.gov/forecasts/aeo/electricity_generation.cfm.*

[302] Technical Support Document—''Review of Electric Utility Integrated Resource Plans'' (May 2015), available in the rulemaking docket EPA–HQ–OAR–2013–0495.

2. Use of Cost Estimates From DOE/NETL and DOE/EIA

In the January 2014 proposal, the EPA relied mostly on the cost projections for new fossil fuel-fired generating sources that were informed by cost studies conducted by DOE/NETL. The EPA relied on the EIA's AEO 2013 projections for non-fossil based generating sources (*i.e.,* nuclear, renewables, etc.). For this final rule, the EPA continues to rely most heavily on DOE/NETL cost projections for fossil fuel generating technologies and on the updated DOE/EIA AEO 2014 for nuclear and other base load non-fossil generation technologies.

a. DOE/NETL Cost and Performance Studies

The DOE/NETL ''Cost and Performance Baselines for Fossil Energy Plants'' are a series of studies conducted by NETL to establish estimates for the cost and performance of combustion and gasification based power plants with and without CO_2 capture and storage.[303] The studies evaluate numerous technology configurations utilizing different coal ranks and natural gas.

The EPA relied on those sources because the NETL studies are the most comprehensive and transparent of the available cost studies and NETL has a reputation in the power sector industry for producing high quality, reliable work.[304] The NETL studies were extensively peer reviewed.[305] The EPA Science Advisory Board Work Group considering the adequacy of the peer review noted the EPA staff's statement that ''the NETL studies were all peer reviewed under DOE peer review protocols'', further noted the EPA staff's statement that ''the different levels of review of these DOE documents met the requirements to support the analyses as defined by the EPA Peer Review Handbook,'' and concluded that ''peer review on the DOE documents'' was conducted ''at a level required by agency guidance.'' [306]

The cost estimates were indicated by DOE/NETL to carry an accuracy of −15 percent to +30 percent on the capital costs, consistent with a AACE Class 4 cost estimate—*i.e.,* a ''feasibility study'' level of design engineering.[307] The DOE/NETL further notes that ''The value of the study lies not in the absolute accuracy of the individual case results but in the fact that all cases were evaluated under the same set of technical and economic assumptions. This consistency of approach allows meaningful comparisons among the cases evaluated.'' [308]

For the final standard, the EPA made particular use of the most recent NETL cost estimates for post-combustion CCS, which reflect up-to-date vendor quotes and incorporate the post-combustion capture technology—the Shell Cansolv amine-based process—that is being utilized at the Boundary Dam Unit #3 facility.[309] The EPA used this latest version of the NETL studies not only to assure that it considers the most up-to-date information but also to address public comments criticizing the proposal for relying on out-of-date cost information.

b. Other Studies That Corroborate NETL Cost Estimates

A variety of government, industry and academic groups routinely conduct studies to estimate costs of new generating technologies. These studies use techno-economic models to predict the cost to build a new generating facility at some point in the future. These studies often use levelized cost of electricity (LCOE) to summarize costs and to compare the competiveness of the different generating technologies.

A variety of groups have recently published LCOE estimates for new dispatchable generating technologies. Those are shown below in Table 10. The table shows LCOE projections from the EPA's January 2014 proposal, from studies conducted by the Electric Power Research Institute (EPRI),[310] by the DOE's Energy Information Administration (EIA) in their 2015 Annual Energy Outlook (AEO 2015), by the DOE's National Energy Technology Laboratory (NETL), and by researchers from the Department of Engineering and Public Policy at the Carnegie Mellon University (CMU) in Pittsburgh, PA.

The Global CCS Institute [311] has recently published a report that examines costs of major low and zero emissions technologies currently available for power generation and compares the predicted LCOEs of those technologies. Importantly, the analysis presented in the report uses cost and performance data from several recent studies, and applies a common methodology and economic parameters to derive comparable lifetime costs. Analysis and findings in the paper reflect costs specific to the U.S.

The fact that these various groups have conducted independent studies and that the results of those independent studies are reasonably consistent with the estimates of DOE/NETL are further indications that the DOE/NETL cost estimates are reasonable.

[303] *http://www.netl.doe.gov/research/energy-analysis/energy-baseline-studies.*

[304] The NETL costs and studies are often cited in academic and other publications.

[305] The initial NETL study ''Cost and Performance Baseline for Fossil Energy Plants, Vol. 1: Bituminous Coal and Natural Gas to Electricity'' (2006) was subject to peer review by industry experts, academia, and government research and regulatory agencies. Subsequent iterations of the study were not further peer reviewed because the modeling procedures used in the cost estimation were not revised.

[306] Letter from James Mihelcic, Chair, SAB Work Group on EPA Planned Actions for SAB Consideration of the Underlying Science to Members of the Chartered SAB and SAB Liaisons (page 3, Jan. 24, 2014). *http://yosemite.epa.gov/sab/sabproduct.nsf/F43D89070E89893485257C5A007AF573/$File/SAB+work+grp+memo+w+attach+20140107.pdf.* The SAB's statement that these guidance documents ''require'' any specific peer review is an overstatement, since guidance documents, by definition, do not mandate any specific course of action.

[307] Recommended Practice 18R–97 of the Association for the Advancement of Cost Engineering International (AACE) describes a Cost Estimate Classification System as applied in Engineering, Procurement and Construction for the process industries.

[308] ''Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity'' Rev 2a (Sept 2013); DOE/NETL–2010/1397, page 9.

[309] Cost and Performance Baseline for Fossil Energy Plants Volume 1a: Bituminous Coal (PC) and Natural Gas to Electricity, Revision 3, July 6, 2015, DOE/NETL–2015/1723.

[310] EPRI is a non-profit organization, headquartered in Palo Alto, CA, that conducts research on issues related to the U.S. electric power industry (*www.epri.com*).

[311] *www.globalccsinstitute.com.*

TABLE 10—SELECTION OF LEVELIZED COST OF ELECTRICITY (LCOE) PROJECTIONS

New generation technology	Lazard [312] $2014/MWh	EPRI [313] $2011/MWh	AEO2015 [314] $2013/MWh*	DOE/NETL [315] $2011/MWh*	CMU [316] $2010/MWh	GCCSI [317]** $2014/MWh
SCPC—no CCS	66	62–77	95	76–95	59	78
SCPC—full CCS	151	102–137	—	140–176	—	115–160
SCPC—16% CCS	—	—	—	92–117	—	—
Nuclear***	92–132	85–97	87–115	—	—	86–102
Biomass	87–116	90–155	94–113	—	—	123–137
IGCC	102	82–96	116	94–120	—	—
IGCC—full CCS	171	105–136	144	142–178	—	—
NGCC	61—87	33—65	73	58	63	60

* EIA, in cost projections for SCPC and IGCC with no CCS, includes a climate uncertainty adder (CUA), which is a 3-percentage point increase in the cost of capital. In contrast, DOE/NETL utilized conventional financing for cases without CCS and utilized high-risk financial assumptions for cases that include CCS.

** The Global CCS Institute provided range for coal with full CCS (shown as ''CCS(coal)'' in Figure 5.2 of the referenced report) reflects a combination of costs for both PC and IGCC coal plants.

*** EIA AEO assumes use of Westinghouse AP1000 technology. Other groups assume a wider range of technology options.

The LCOE values from the Lazard, EPRI, and NETL studies are presented as a range. The EPRI costs incorporate uncertainty reflecting the range of inputs (*i.e.,* capital costs, fuel costs, fixed and variable O&M, etc.). The NETL costs are indicated to carry an accuracy of −15 percent to + 30 percent, consistent with a ''feasibility study'' level of design. The range in Table 10 is the NETL projected costs with the −15 percent to +30 percent uncertainty on the capital costs. Overall, as can be seen from the results in Table 10, the range of LCOE estimates from the different groups are in reasonable agreement with the DOE/NETL estimates most often representing the most conservative of the estimates shown.

The EIA cost estimates include a climate uncertainty adder (CUA)—represented by a three percent increase to the weighted average cost of capital—to certain coal-fired capacity types. The EIA developed the CUA to address inconsistencies between power sector modeling absent GHG regulation and the widespread use of a cost of CO_2 emissions in power sector resource planning. The CUA reflects the additional planning cost typically assigned by project developers and utilities to GHG-intensive projects in a context of climate uncertainty. The EPA believes the CUA is consistent with the industry's planning and evaluation framework (demonstrable through IRPs and PUC orders) and is therefore pertinent when evaluating the cost competitiveness of alternative generating technologies. The EPA believes the CUA is relevant in considering the range of costs that power companies are willing to pay for generation alternatives to natural gas.

c. Industry Information That Corroborates NETL Cost Estimates

Information from vendors of CCS technology also supports the reliability of the cost estimates the EPA is using here.[318] Specifically, the EPA had conversations with representatives from Summit Carbon Capture, LLC regarding available cost information. Cost estimates provided by another leading provider of CCS technology likewise are consistent (indeed, somewhat less than) the estimates the EPA is using for purposes of cost analysis in the rule.

Summit Carbon Capture's primary business is large-scale carbon capture from power and other industrial projects and use of the captured CO_2 for EOR.[319] Summit is actively working with several different technology companies offering CO_2 capture systems, including the leading equipment manufacturers for fossil fuel power production equipment. Their current projects include the 400 MW IGCC Texas Clean Energy Project and the Caledonia Clean Energy Project—a new project underway in the United Kingdom—and a variety of other projects under development which are not yet public.

Summit is also interested in potentially retrofitting CCS onto existing coal-fired plants for the purpose of capturing CO_2 for sale to EOR markets. Summit provided the EPA with copies of slides from a presentation that it has used in different public forums.[320] The presentation focused on costs to retrofit available carbon capture equipment at an existing PC power plant that is ideally located to take advantage of opportunities to sell captured CO_2 for use in EOR operations. Summit received proprietary costing information from numerous technology providers and that information, along with other publically available information, was used to develop their cost predictions.[321] Though the primary focus of their effort was to examine costs associated with retrofitting CCS to an existing coal fired power plant, Summit Power also calculated costs for several new generation scenarios—including the cost of a new NGCC, a new SCPC, a new SCPC with full CCS, and a new SCPC with partial CCS at 50 percent. The costs are reasonably consistent with costs predicted by NETL, EIA, EPRI and others. The company ultimately concluded that ''in a world of uncertain gas prices, falling CO_2 capture

[312] Lazard's Levelized Cost of Energy Analysis—Version 8.0 (Sept 2014); available at *http://www.lazard.com/media/1777/levelized_cost_of_energy_-_version_80.pdf* and in the rulemaking docket.

[313] ''Program on Technology Innovation: Integrated Generation Technology Options 2012; Report 1026656; Available at: *www.epri.com*.

[314] ''Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2015'', Available at: *www.eia.gov/forecasts/aeo/electricity_generation.cfm*; the LCOE values displayed incorporate −10%/+30% for uncertainty for biomass and nuclear.

[315] ''Cost and Performance Baseline for Fossil Energy Plants Supplement: Sensitivity to CO_2 Capture Rate in Coal-Fired Power Plants'' DOE/NETL–2015/1720 (June 22, 2015).

[316] CMU is Carnegie Mellon University; Zhai, H., Rubin, E.; ''Comparative Performance and Cost Assessments of Coal- and Natural Gas-Fired Power Plants under a CO_2 Emission Performance Standard Regulation'', *Energy & Fuels,* 2013, 27, 4290, Table 1.

[317] ''The Costs of CCS and other Low-Carbon Technologies—2015 update'' July 2015, Global CCS Institute, Available at: *http://hub.globalccsinstitute.com/sites/default/files/publications/195008/costs-ccs-other-low-carbon-technologies-2015-update.pdf.*

[318] See Section V.F above, explaining that the D.C. Circuit has repeatedly stated that vendor statements are probative in demonstrating that a technology is adequately demonstrated under section 111.

[319] *http://www.summitpower.com/projects/carbon-capture/.*

[320] ''Coal's Role in a Low Carbon Energy Environment'', presented at 2015 Euromoney Power & Renewables Conference, remarks by Jeffrey Brown (amended to address EPA questions on the original). Available in the rulemaking docket.

[321] No proprietary or business confidential information was shared with the EPA. No specific vendors were mentioned by name during discussions with Summit Power. Summit also used available DOE/NETL and EIA cost information.

equipment prices, improving CCS process efficiency, and possible compliance costs . . . existing coal plants retrofitted with available CCS equipment can be cost competitive with development of new NGCC generation.'' [322]

In June 2012, Alstom Power released a report entitled ''Cost assessment of fossil power plants equipped with CCS under typical scenarios''.[323] The study examined costs for a new coal-fired power plant implementing post-combustion CCS (full CCS) in Europe, in North America, and in Asia. The results for the North American case—along with similar cost estimates from Summit—are shown in Table 11 below. The DOE/NETL estimated costs are also included for comparison. The results show predicted costs for a new SCPC ranging from $53/MWh to $82/MWh and costs to implement full CCS ranging from $97/MWh to $143/MWh. Costs to implement varying levels of partial CCS are also provided for comparison. The industry cost estimates are on the lower end of the range of costs predicted from other techno-economic studies (see Table 11 below) and, like those economic studies, are affected by the specific assumptions. As with the techo-economic studies presented earlier in Table 10, there is relatively good agreement among these projected costs and the DOE/NETL costs. There is relatively good agreement in the incremental levelized cost to implement full CCS on the new SCPC units (ranging from 74 to 85 percent) and to implement 50 percent CCS on the new SCPC unit (from 41 to 45 percent increase). These industry estimates are also lower than the DOE/NETL estimates for both full and 50 percent partial CCS (with the incremental cost percentage for full CCS being almost identical), providing further support for the reasonableness of the EPA using the NETL cost estimates here.

TABLE 11—INDUSTRY LCOE ESTIMATES FOR IMPLEMENTATION OF POST-COMBUSTION CCS [324]

	Summit $/MWh	Alstom $/MWh*	DOE/NETL $/MWh
SCPC	64.5	52.6	82.3
SCPC + full CCS	117.6	97.4	152.4
Full CCS incremental cost, %	82.3%	85.0%	85.2%
SCPC + 50% CCS	91.1	—	123.6
50% CCS incremental cost, %	41.2%	—	50.1%
SCPC + 35% CCS	—	—	114.7
SCPC + 16% CCS	—	—	100.5
NGCC**	47.7	35.0	**52.0

* Costs are from Figure 2 in the referenced Alstom report (North American case); costs are presented as €/MWh in the report. The costs were converted to $/MWh assuming a conversion rate of 1 USD = 0.76 € (in 2012).

** NGCC cost is estimated by the EPA using NETL information. Assumed natural gas prices = Summit ($4/mmBtu); Astom ($3.9/mmBtu); EPA ($5.00/mmBtu).

The EPA notes that in its public comments, Alstom maintained that ''no CCS projects that would [sic] be considered cost competitive in today's energy economy.'' [325] As explained above, no steam electric EGU would be cost competitive even without CCS—and that is substantiated in the projected costs presented above in Table 11 where NGCC is consistently the most economic new generation option when compared to the other listed technologies. Alstom does not explain (or address) why the cost premium for partial CCS would be a decisive deterrent for capacity that would otherwise be constructed. More important, Alstom does not challenge the specific cost estimates used by the EPA at proposal, nor disavow its own estimates of CCS costs (which are even less) which it is publically disseminating in the marketplace. See also Section V.F.3 above, quoting Alstom's press release stating unequivocally that ''CCS works and is cost-effective''. The EPA reasonably is relying on the specific Alstom estimates which it is using for its own commercial purposes, and not on the generalized concerns presented in its public comments.

d. Use of Cost Information From EIA Annual Energy Outlook (AEO)

For the January 2014 proposal the EPA chose to rely on the EIA AEO 2013 cost projections for non-fossil based generation. The AEO presents long-term annual projections of energy supply, demand, and prices focused on U.S. energy markets. The predictions are based on results from EIA's National Energy Modeling System (NEMS). The AEO costs are updated annually, they are highly scrutinized, and they are widely used by those involved in the energy sector.

In the January 2014 proposal, the EPA presented LCOE costs for new non-fossil dispatchable generation (see 77 FR 1477, Table 7) from the AEO 2013. Those costs were updated as part of the AEO 2015 release. The estimated cost for all of these technologies decreased from AEO 2013 to AEO 2014 and AEO 2015. This was due to changes in the interest rates that resulted in lower financing costs relative to those used the AEO 2013.[326] The EIA commissioned a comprehensive update of its capital cost assumptions for all generation technologies in 2013. Fuel cost and

[322] Others have come to similar conclusions—that retrofit of CCS technology at existing coal-fired power plants can be feasible—*e.g.,* ''The results indicate that for about 60 gigawatts of the existing coal-fired capacity, the implementation of partial CO_2 capture appears feasible, though its cost is highly dependent on the unit characteristics and fuel prices.'' (Zhai, H.; Ou, Y.; Rubin, E.S.; ''Opportunities for Decarbonizing Existing U.S. Coal-fired Plants via CO_2 Capture, Utilization, and Storage'', accepted for publication in *Env. Sci & Tech.* (2015).

[323] Leandri, J., Skea, A., Bohtz, C., Heinz, G.; ''Cost assessment of fossil power plants equipped with CCS under typical scenarios'', Alstom Power, June 2012. Available in the rulemaking docket: EPA–HQ–OAR–2013–0495.

[324] Note that in other tables in this preamble, the EPA has presented LCOE values from the DOE/NETL work as a range in order to incorporate the uncertainty on the capital costs. The range is not present here for easy comparison with the industry costs which were not provided as a range. The full range of DOE/NETL costs for each of the cases presented can be found in Exhibit A–3 in ''Cost and Performance Baseline for Fossil Energy Plants Supplement: Sensitivity to CO_2 Capture Rate in Coal-Fired Power Plants'', DOE/NETL–2015/1720 (June 2015), p. 18.

[325] Alstom Comment p. 3 (Docket entry: EPA–HQ–OAR–2013–0495–9033). The comment also urged the EPA to evaluate costs without considering EOR opportunities (which in fact is our methodology, albeit a conservative one), and without considering possible subsidies. Id. The LCOE and capital cost estimates above are direct cost comparisons, again consistent with the commenter's position.

[326] *www.eia.gov/oiaf/beck_plantcosts/pdf/updatedplantcosts.pdf.*

financial assumptions are updated for each edition of the Annual Energy Outlook.

e. Accounting for Uncertainty of Projected Costs

As previously mentioned, the projected costs are dependent upon a range of assumptions including the projected capital costs, the cost of financing the project, the fixed and variable O&M costs, the projected fuel costs, and incorporation of any incentives such as tax credits or favorable financing that may be available to the project developer. There are also regional or geographic differences that affect the final cost of a project. The LCOE projections in this final action are not intended to provide an absolute cost for a new project using any of these respective technologies. Large construction projects—as these would be—would be subjected to detailed cost analyses that would take into consideration site-specific information and specific design details in order to determine the project costs.

The DOE/NETL noted that the cost estimates from their studies carry an accuracy in the range of −15 percent to +30 percent, which is consistent with a ''feasibility study'' level of design. They also noted that the value of the studies lies ''not in the absolute accuracy of the individual case results but in the fact that all cases were evaluated under the same set of technical and economic assumptions. This consistency of approach allows meaningful comparisons among the cases evaluated.''

The EIA AEO 2015 presented LCOE costs as a single point estimate representing average nationwide costs and separately as a range to represent the regional variation in costs. In order to compare the fossil fuel generation technologies from the NETL studies with the cost projections for non-fossil dispatchable technologies from EIA AEO 2015, we assume that the EIA studies would carry a similar level of uncertainty (*i.e.,* +30 percent) and we present the AEO 2015 projected costs as the average nationwide LCOE with a range of −10 percent to +30 percent to account for uncertainty.[327] The EIA does not provide uncertainty estimates in the AEO cost projections. However, nuclear experts from EIA staff have indicated to the EPA that a range of uncertainty of −10 percent to +30 percent on the capital component of the LCOE can be expected based on market uncertainties. Specifically, these staff experts expect that nuclear plants currently under construction would not have capital costs under estimates and that one could expect to see a 30 percent ''upside'' variation in capital cost. There is also insufficient market data to get a good statistical range of potential capital cost variation (*i.e.,* only two plants under construction, neither complete). This is reasonably consistent with estimates for nuclear costs estimated by Lazard (see Table 8 above) which likewise reflect a similar level of cost uncertainty. The Lazard nuclear costs show a range of projected levelized capital cost from $73/MWh to $110/MWh—a range of 50 percent, very similar to the 40 percent range (*i.e.,* −10 percent to +30 percent) suggested by EIA nuclear experts. The Global CCS Institute, in its most recent cost update, also provides nuclear costs as a range from $86/MWh to $102/MWh.[328]

3. Use of Costs From Current Projects

Although we are relying on cost estimates drawn from techno-economic models, we recognize that there are a few steam electric plants that include CCS that have been built, or are being constructed. Some information about the costs (or cost-to-date) for these projects is known. We discuss in this section the costs at facilities which have installed or are installing CCS, why the EPA does not consider those costs to be reasonably predictive of the costs of the next new plants to be built, and why the EPA considers that the next new plants will have lower costs along the lines predicted by NETL.[329]

The Boundary Dam Unit #3 facility utilizing post-combustion capture from Shell Cansolv is now operational. Petra Nova, a joint venture between NRG Energy Inc. and JX Nippon Oil & Gas Exploration, is currently constructing a post-combustion capture system at NRG's WA Parish generating station near Houston, TX. The post-combustion capture system will utilize MHI amine-based solvents and is currently being constructed with plans to initiate operation in 2016.[330]

Construction on Mississippi Power's Kemper County Energy Center IGCC facility is now nearly complete. The combined cycle portion of the facility has been generating power using natural gas. The gasification portion of the facility and the carbon capture system are undergoing system checks and training to enable commercial operations using a UOP Selexol™ pre-combustion capture system in early 2016.[331]

Another full-scale project, the Summit Power Texas Clean Energy Project has not commenced construction but remains a viable project. Several other full-scale projects have been proposed and have progressed through the early stages of design, but have been cancelled or postponed for a variety of reasons.

Some cost information is also available for small demonstration projects—including those that have been supported by USDOE research programs. These projects would include Alabama Power's demonstration project at Plant Barry and the AEP/Alstom demonstration at Plant Mountaineer.

Many commenters felt that the EPA should rely on those high costs when considering whether the costs are reasonable. The costs from these large-scale projects appear to be consistently higher than those projected by techno-economic models. However, the costs from these full-scale projects represent first-of-a-kind (FOAK) costs and, it is reasonable to expect these costs to come down to the level projected in the NETL and other techno-economic studies for the next new projects that are built—which are the sources that would be subject to this standard.

Significant reductions in the cost of CO_2 capture would be consistent with overall experience with the cost of pollution control technology. A significant body of literature suggests

[327] EIA does not provided uncertainty estimates in the AEO cost projections. However, EIA staff have indicated to the EPA that a range of uncertainty of −10%/+30% on the capital component of the LCOE can be expected based on market uncertainties. See memorandum ''Range of uncertainty for AEO nuclear costs'' available in the rulemaking docket, EPA–HQ–OAR–2013–0495.

[328] ''The Costs of CCS and other Low-Carbon Technologies—2015 update'' July 2015, Global CCS Institute, Available at: *http://hub.globalccsinstitute.com/sites/default/files/publications/195008/costs-ccs-other-low-carbon-technologies-2015-update.pdf.*

[329] The EPA notes that two of these facilities, Kemper and TCEP, received both assistance from DOE under EPAct05 and the IRC section 48A tax credit; and that the AEP Mountaineer pilot project received assistance from DOE under EPAct05. Under the most extreme interpretations of those provisions offered by commenters, the EPA would be precluded from any consideration of any information from those sources, including cost information, in showing whether a system of emission reduction is adequately demonstrated. We note, however, that many of these same commenters urged consideration of the cost information from these sources. In fact, the EPA is not relying on information about the costs of these sources to determine the BSER or the standards of performance in this rulemaking, and the EPA is discussing the cost information here to explain why not. Accordingly, this discussion of cost information from these sources is not precluded by the EPAct05 and IRC section 48A provisions and, even if it is precluded, that would have no impact on the EPA's determination of the BSER and the standards of performance in this rule.

[330] *http://www.nrg.com/sustainability/strategy/enhance-generation/carbon-capture/wa-parish-ccs-project/.*

[331] *http://www.mississippipower.com/about-energy/plants/kemper-county-energy-facility/facts.*

that the per-unit cost of producing or using a given technology declines as experience with that technology increases over time, and this has certainly been the case with air pollution control technologies. Reductions in the cost of air pollution control technologies as a result of learning-by-doing, research and development investments, and other factors have been observed over the decades. We expect that the costs of capture technology will follow this pattern.

The NETL cost estimates reasonably account for this documented phenomenon. Specifically, ''[I]n all cases, the report intends to represent the next commercial offering, and relies on vendor cost estimates for component technologies. It also applies process contingencies at the appropriate subsystem levels in an attempt to account for expected but undefined costs (a challenge for emerging technologies).'' [332]

Commenters argued that the next plants to be built would still reflect first-of-a-kind costs, pointing to the newness of the technology and the lack of operating experience, *i.e.* the alleged absence of learning by doing. The EPA disagrees. In addition to operating experience from operating and partially constructed CCS projects, substantial research efforts are underway providing a further knowledge base to reduce CO_2 capture costs and to improve performance.

The DOE/NETL sponsors an extensive research, development and demonstration program that is focused on developing advanced technology options that will dramatically lower the cost of capturing CO_2 from fossil fuel energy plants compared to currently available capture technologies. The large-scale CO_2 capture demonstrations that are currently planned and in some cases underway, under DOE's initiatives, as well as other domestic and international projects, will generate operational knowledge and enable continued commercialization and deployment of these technologies. Gas absorption processes using chemical solvents, such as amines, to separate CO_2 from other gases have been in use since the 1930s in the natural gas industry and to produce food and chemical grade CO_2. The advancement of amine-based solvents is an example of technology development that has improved the cost and performance of CO_2 capture. Most single component amine systems are not practical in a flue gas environment as the amine will rapidly degrade in the presence of oxygen and other contaminants. The Fluor Econamine FG process, the process modeled in the NETL cost study for the SCPC cases, uses a monoethanolamine (MEA) formulation specially designed to recover CO_2 and contains a corrosion inhibitor that allows the use of less expensive, conventional materials of construction. Other commercially available processes use sterically hindered amine formulations (for example, the Mitsubishi Heavy Industries KS–1 solvent) which are less susceptible to degradation and corrosion issues.

The DOE/NETL and private industry are continuing to sponsor research on advanced solvents (including new classes of amines) to improve the CO_2 capture performance and reduce costs.

As noted in Section V.H.7.d above, SaskPower has created the CCS Global Consortium to facilitate further knowledge regarding, and use of, carbon capture technology.[333] This consortium provides SaskPower the opportunity to share its knowledge and experience with global energy leaders, technology developers, and project developers. SaskPower, in partnership with Mitsubishi and Hitachi, is also helping to advance CCS knowledge and technology through the creation of the Shand Carbon Capture Test Facility (CCTF).[334] The test facility will provide technology developers with an opportunity to test new and emerging carbon capture systems for controlling carbon emissions from coal-fired power plants.

We also note certain features of the commercial plants already built that suggest that their costs are uniquely high, and otherwise not fairly comparable to the costs of plants meeting the NSPS using the BSER. Most obviously, many of these projects involve deeper capture than the partial CCS that the EPA assumes in this final action. In addition, cost overruns at the Kemper facility, mentioned repeatedly in the public comments, resulted in major part from highly idiosyncratic circumstances, and are related to the cost of the IGCC system, not to the cost of CCS.[335] The EPA does not believe that these unusual circumstances are a reasonable basis for assessing costs of either CCS or IGCC here.

4. Cost Competitiveness of New Coal Units

As the EPA noted, all indications suggest that very few new coal-fired power plants will be constructed in the foreseeable future. Although a small number of new coal-fired power plants have been built recently, the industry generally is not building these kinds of power plants at present and is not expected to do so for the foreseeable future. The reasons include the current economic environment and improved energy efficiency, which has led to lower electricity demand, and competitive current and projected natural gas prices. On average, the cost of generation from a new NGCC power plant is expected to be lower than the cost of generation from a new coal-fired power plant, and the EPA has concluded that, even in the absence of the requirements of this final rule, very few new coal-fired power plants will be built in the near term.

Some commenters, however, disagreed with this conclusion. They contended instead that it is the CCS-based NSPS that would preclude such new generation. However, as the EPA has discussed, there is considerable evidence that utilities and project developers are moving away—or have already moved away—from a long term dependence on coal-fired generating sources. A review of publicly available integrated resource plans show that many utilities are not considering construction of new coal-fired sources without CCS. See Section V. H.3 above. Few new coal-fired generating sources have commenced construction in the past 5 years and, of the projects that are currently in the development phase, the EPA is only aware of projects that will include CCS in the design. As we have noted in this preamble, the bulk of new

[332] ''Cost and Performance Baseline for Fossil Energy Plants Volume 1a: Bituminous Coal (PC) and Natural Gas to Electricity Revision 3'', DOE/NETL–2015/1723 (July 2015) at p. 38.

[333] *http://www.saskpowerccs.com/consortium/.*

[334] *http://www.saskpowerccs.com/ccs-projects/shand-carbon-capture-test-facility/.*

[335] See Independent Monitor's Prudency Evaluation Report for the Kemper County IGCC Project (prepared for Mississippi Public Utilities Staff), available at *www.psc.state.ms.us/InsiteConnect/InSiteView.aspx?model=INSITE_CONNECT&queue=CTS_ARCHIVEQ&docid=328417* (''Report''). As documented in this Report, costs escalated significantly because the developers adopted a ''compressed schedule'' in an attempt to obtain the IRC 48A tax credit, resulting in ''engineering and design changes which are a normal result of detailed engineering and design . . . occurring at the same time as, rather than ahead of, construction activities'', which did not allow for proper sequencing during construction. This '' 'just-in-time' approach to engineering and procurement (meaning that the engineering was often completed shortly before material procurement and construction activities) resulted in a greater number of construction work-arounds, congestion of construction craft labor in the field, inefficiencies and additional steps that became necessary during construction to cope with this just-in-time engineering, procurement and construction approach.'' Report, p. 6. Ironically, work was still completed too late to obtain the tax credit. Id. p. 15.

generation that has been added recently has been either natural gas-fired or renewable sources. Overall, the EPA remains convinced that the energy sector modeling is reflecting the realities of the market in predicting very few new coal-fired power plants in the near future—even in the absence of these final standards.

In addition, we note that the Administration's CCS Task Force report recognized that CCS would not become more widely available without the advent of a regulatory framework that promoted CCS or provided a strong price signal for CO_2. In this regard, we note American Electric Power's statements regarding the need for federal requirement for GHG control to aid in cost recovery for CCS projects, to attract other investment partners, and thereby promote advancement and deployment of CCS technology: ''as a regulated utility, it is impossible to gain regulatory approval to recover our share of the costs for validating and deploying the technology without federal requirements to reduce greenhouse gas emissions already in place. The uncertainty also makes it difficult to attract partners to help fund the industry's share''.[336] Indeed, AEP has stated that CCS is important for the very future of the industry: ''AEP still believes the advancement of CCS is critical for the sustainability of coal-fired generation.'' [337] This final rule's action is an important component in developing that needed regulatory framework.

5. Accuracy of Cost Estimates for Transportation and Geologic Sequestration

The EPA's estimates of costs take into account the transport of CO_2 and sequestration of captured CO_2. Estimates of transport and sequestration costs—approximately $5–$15 per ton of CO_2—are based on DOE NETL studies and are also consistent with other published studies.[338] For transport, costs reflect pipeline capital costs, related capital expenditures, and O&M costs. Sequestration cost estimates reflect the cost of site screening and evaluation, the cost of injection wells, the cost of injection equipment, operation and maintenance costs, pore volume acquisition expense, and long term liability protection. These sequestration costs reflect the regulatory requirements of the Underground Injection Control Class VI program and GHGRP subpart RR for geologic sequestration of CO_2 in deep saline formations, which are discussed further in Sections V. M. and N below.[339]

Based on DOE/NETL studies, the EPA estimated that the total CO_2 transportation, storage, and monitoring (TSM) cost associated with EGU CCS would comprise less than 5.5 percent of the total cost of electricity in all capture cases modeled—approximately $5–$15 per ton of CO_2.[340] The range of TSM costs the EPA relied on are broadly consistent with estimates provided by the Global Carbon Capture and Storage Institute as well.[341] Some commenters suggested that the EPA underestimated the costs associated with transporting captured CO_2 from an EGU to a sequestration site.[342] Specifically, commenters suggested that the EPA's estimated costs for constructing pipelines were lower than costs based on actual industry experience. Commenters also opined that the EPA's assumed length of pipeline needed between the EGU and the sequestration site is not reasonable and that the DOE/NETL study upon which the EPA relied does not account for CO_2 transport costs when EOR is not available.

The EPA believes its estimates of transportation and sequestration costs are reasonable. First, the EPA in fact includes cost estimates for CO_2 transport when EOR opportunities are not available—consistent with its overall conservative cost methodology of assuming no revenues from sale of captured CO_2. Specifically, the EPA estimates transport, storage and monitoring (TSM) costs of $5–$15 per ton of CO_2 for non-EOR applications.[343] This estimate is reflected in the LCOE comparative costs.[344]

The EPA also carefully reviewed the assumptions on which the transport cost estimates are based and continues to find them reasonable. The NETL studies referenced in Section V.I.2 above based transport costs on a generic 100 km (62 mi) pipeline and a generic 80 kilometer pipeline.[345] At least one study estimated that of the 500 largest point sources of CO_2 in the United States, 95 percent are within 50 miles of a potential storage reservoir.[346] As a point of reference, the longest CO_2 pipeline in the United States is 502 miles.[347] For new sources, pipeline distance and costs can be factored into siting and, as discussed in Section V.M, there is widespread availability of geologic formations for geologic sequestration (GS). Moreover, data from the Pipeline and Hazardous Materials Safety Administration show that in 2013 there were 5,195 miles of CO_2 pipelines operating in the United States. This represents a seven percent increase in CO_2 pipeline miles over the previous year and a 38 percent increase in CO_2 pipeline miles since 2004. For the reasons outlined above, the EPA believes its estimates have a reasoned basis. See also Section V.M below further discussing the current availability of CO_2 pipelines.

With respect to sequestration, certain commenters argued that the EPA's cost analysis failed to account for many contingencies and uncertainties (surface and sub-surface property rights in particular), ignored the costs of GHGRP subpart RR, and also was not representative of the costs associated with specific GS site characterization, development, and operation/injection of monitoring wells. Commenter American Electric Power (AEP) referred to its own

[336] *www.aep.com/newsroom/newsreleases/?id=1704.*

[337] ''CCS LESSONS LEARNED REPORT American Electric Power Mountaineer CCS II Project Phase 1'', prepared for The Global CCS Institute Project # PRO 004, January 23, 2012, page 2. Available at: *www.globalccsinstitute.com/publications/ccs-lessons-learned-report-american-electric-power-mountaineer-ccs-ii-project-phase-1*; See also AEP FEED Study at pp. 4, 63, Available at: *www.globalccsinstitute.com/publications/aep-mountaineer-ii-project-front-end-engineering-and-design-feed-report.*

[338] *Updated Costs (June 2011 Basis) for Selected Bituminous Baseline Cases* (DOE/NETL–341/082312); *Cost and Performance of PC and IGCC Plants for a Range of Carbon Dioxide Capture* (DOE/NETL–2011/1498); *Cost and Performance Baseline for Fossil Energy Plants* (DOE/NETL–2010/1397); *Economic Evaluation of* CO_2 *Storage and Sink Enhancement Options, Tennessee Valley Authority, NETL and EPRI, December 2002; Carbon Dioxide and Transport and Storage Costs in NETL Studies* (DOE/NETL–2013/1614), March 2013; *Carbon Dioxide and Transport and Storage Costs in NETL Studies* (DOE/NETL–2014/1653), May 2014; *Cost and Performance Baseline for Fossil Energy Power Plants, Volume 1a: Bituminous Coal (PC) and Natural Gas to Electricity* (DOE–NETL–2015/1723), July 2015.

[339] Carbon Dioxide and Transport and Storage Costs in NETL Studies. DOE/NETL–2013/1614. March 2013. P. 13.

[340] RIA at section 5.5; proposed rule RIA at 5–30.

[341] *http://hub.globalccsinstitute.com/sites/default/files/publications/12786/economic-assessment-carbon-capture-and-storage-technologies-2011-update.pdf.*

[342] See, for example, comments from American Electric Power, pp 97–8 (Docket entry: EPA–HQ–OAR–2013–0495–10618), Southern Company, pp. 47–48 (Docket entry: EPA–HQ–OAR–2013–0495–10095), and Duke Energy p. 28 (Docket entry: EPA–HQ–OAR–2013–0495–9426).

[343] See RIA at section 5.5 and proposed RIA at 5–30.

[344] See RIA at section 5.5.

[345] The pipeline diameter was sized for this to be achieved without the need for recompression stages along the pipeline length.

[346] JJ Dooley, CL Davidson, RT Dahowski, MA Wise, N Gupta, SH Kim, EL Malone (2006), Carbon Dioxide Capture and Geologic Storage: A Key Component of a Global Energy Technology Strategy to Address Climate Change. Joint Global Change Research Institute, Battelle Pacific Northwest Division. PNWD–3602. College Park, MD.

[347] A Review of the CO_2 Pipeline Infrastructure in the U.S., April 21, 2015, DOE/NETL–2014/1681, Office of Fossil Energy, National Energy Technology Laboratory.

experience with the Mountaineer demonstration project. AEP noted that although this project was not full scale, finding a suitable repository, notwithstanding a generally favorable geologic area, proved difficult. The company referred to its estimated cost of expanding the existing Mountaineer plant to a larger scale project, particularly the cost of site characterization and well construction.[348]

The EPA's cost estimates account for the requirements of the Underground Injection Control Class VI program, and GHGRP subpart RR, among them site screening and evaluation costs, costs for injection wells and equipment, O&M costs, and monitoring costs. The estimated sequestration costs include operational and post-injection site care monitoring, which are components of the UIC Class VI requirements, and also reflect costs for sub-surface pore volume property rights acquisition.[349] These estimates are consistent with the costs presented in the study *CO_2 Storage and Sink Enhancements: Developing Comparable Economics,* which incorporates the costs associated with site evaluation, well drilling, and the capital equipment required for transporting and injecting CO_2.[350] [351] Monitoring costs were evaluated based on the methodology set forth in the International Energy Agency Greenhouse Gas R&D Programme's *Overview of Monitoring Projects for Geologic Storage Projects* report.[352]

The EPA's cost estimates for sequestration thus cover all aspects commenters claimed the EPA disregarded. The EPA believes that the use of costs and scenarios presented in the studies referenced are representative for purposes of the cost analysis. The NETL cost estimates upon which the EPA's costs draw directly from the UIC Class VI economic impact analysis.[353] That analysis is based on estimated characteristics for a representative group of projects over a 50-year period of analysis, as well as industry averages for several cost components and sub-components. The EPA also made reasonable assumptions regarding the assumed injection site: A deep saline formation with typical characteristics (*e.g.,* representative depth and pressure).[354]

With respect to AEP's experience with the Mountaineer demonstration project, sequestration siting issues are of course site-specific, and raise individual issues. For this reason, it is inappropriate to generalize from a particular individual experience. In this regard, as explained in Section V.N below, the construction permits issued by the EPA to-date under the Underground Injection Control Class VI regulations required far fewer wells for site characterization and monitoring than AEP found to be necessary at its Mountaineer site. Moreover, notwithstanding difficulties, the company was able to successfully drill and complete wells, and safely inject captured CO_2. The company also indicated it fully expected to be able to do so at full scale and explained how.[355] For discussion of 40 CFR part 98, subpart RR (the GHGRP requirements for geologic sequestration), including costs associated with compliance with those requirements, see Section V.N below.

J. Achievability of the Final Standards

The EPA finds the final standard of 1,400 lb CO_2/MWh-g to be achievable over a wide range of variable conditions that are reasonably likely to occur when the system is properly designed and operated. As discussed elsewhere, the final standard reflects the degree of emission limitation achievable through the application of the BSER which we have determined to be a highly efficient SCPC implementing partial CCS at a level sufficient to achieve the final standard—for such a unit utilizing bituminous coal that would be approximately 16 percent. In determining the predicted cost and performance of such a system, the EPA utilized information contained in updated DOE/NETL studies that assumed use of bituminous coal and an 85 percent capacity factor. Here we examine the effects of deviating from those assumed operational parameters on the achievability of the final standard of performance.[356] This is in keeping with the requirement that a standard of performance must be achievable accounting for all normal operating variability when a control system is properly designed, maintained, and operated. See Section III.H.1.c above.

1. Operational Fluctuations, Start-Ups, Shutdowns, and Malfunctions

Importantly, compliance with the standard must be demonstrated over a 12-operating-month average. The total CO_2 emissions (pounds of CO_2) over 12 operational months are summed and divided by the total gross output (in megawatt-hours) over the same 12 operational months. Such a compliance averaging period is very forgiving of short-term excursions that can be associated with non-routine events such as start-ups, shutdowns, and malfunctions. A new fossil fuel-fired steam generating EGU—if constructed—would, most likely, be built to serve base load power demand and would not be expected to routinely start-up or shutdown or ramp its capacity factor in order to follow load demand. Thus, planned start-up and shutdown events would only be expected to occur a few times during the course of a 12-operating-month compliance period. Malfunctions are unplanned and unpredictable events and emission excursions can happen at or around the time of the equipment malfunction. But a malfunctioning EGU that cannot be operated properly should be shut down until the malfunctioning equipment can be addressed and the EGU can be restarted to operate properly.

The post-combustion capture systems that have been utilized have proven to be reliable. The Boundary Dam facility has been operating full CCS successfully at commercial scale since October 2014. As described earlier, in evaluating results from the Mountaineer slip-

[348] AEP Comments at pp. 93, 96 (Docket entry: EPA–HQ–OAR–2013–0495–10618).

[349] ''Cost and Performance of PC and IGCC Plants for a Range of Carbon Dioxide Capture.'' DOE/NETL–2011/1498 (September 2013) p. 49. Specifically, the report estimates the costs associated with acquiring rights to use the pore space in the geologic formation. Costs are estimated based on studies of subsurface rights acquisition for natural gas storage. The report also estimates costs for land acquisition for surface property rights. Id. p. 48.

[350] Bock, B., R. Rhudy, H. Herzog, M. Klett, J. Davidson, D.G. De La Torre Ugarte, and D. Simbeck. (2003). Economic Evaluation of CO_2 Storage and Sink Enhancement Options, Final Technical Report Prepared by Tennessee Valley Authority for DOE.

[351] As noted above, other sequestration-related costs are also estimated, including injection wells and equipment, pore volume acquisition, and long-term-liability. ''Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity Revision 2a, September 2013 DOE/NETL–2010/1397, p. 55.

[352] ''Overview of Monitoring Requirements for Geologic Storage Projects'', IEA Greenhouse Gas R&D Programme, Report Number PH4/29, November 2004.

[353] Cost Analysis for the Federal Requirements Under the Underground Injection Control Program for Carbon Dioxide Geologic Sequestration Wells, U.S. Environmental Protection Agency Office of Water, EPA 816–R10–013, November 2010, pages 3–1, 5–42.

[354] Economic Evaluation of CO_2 Storage and Sink Enhancement Options, Tennessee Valley Authority, NETL and EPRI, December 2002.

[355] See ''CCS front end engineering & design report: American Electric Power Mountaineer CCS II Project. Phase 1'' at pp. 36–43. The company likewise explained the monitoring regime it would utilize to verify containment, and the well construction it would utilize to guarantee secure sequestration. Id. at pp. 44–54. Available at: *http://www.globalccsinstitute.com/publications/aep-mountaineer-ii-project-front-end-engineering-and-design-feed-report.*

[356] Additional information can be found in a Technical Support Document (TSD)—''Achievability of the Standard for Newly Constructed Steam Generating EGUs'' available in the rulemaking docket.

stream demonstration, AEP and Alstom reported robust steady-state operation during all modes of power plant operation including load changes, and saw an availability of the CCS system of greater than 90 percent.[357]

2. Variations in Coal Type

The use of specific coal types can affect the amount of CO_2 that is emitted from a new coal-fired power plant. As previously discussed, the EPA utilized studies by the DOE/NETL to predict the cost and performance of new steam generating units. Based on those reports, the EPA predicts that a new SCPC burning low rank coal (subbituminous coal or dried lignite) would have an uncontrolled emission rate about 7 percent higher than a similar unit firing typical bituminous coal.[358] The EPA predicts that such a highly efficient new SCPC utilizing subbituminous coal or dried lignite would need to capture approximately 23 percent of the CO_2. The EPA also believes that it is technically feasible to do so, although additional cost would be entailed. The EPA has evaluated those costs and finds them to remain reasonable.[359] As shown in Table 8 above, the predicted cost remains within the estimated range for the other principal base load, dispatchable non-NGCC alternative technologies. Estimated capital cost using these coal types would also be somewhat higher, an estimated 23 percent increase.[360] The EPA finds these increases to be reasonable because, as discussed earlier, the costs are reasonably consistent with capital cost increases in previous NSPS. See Section V.H.4 above.

K. Emission Reductions Utilizing Partial CCS

Although the definition of ''standard of performance'' does not by its terms identify the amount of emissions from the category of sources and the amount of emission reductions achieved as factors the EPA must consider in determining the ''best system of emission reduction,'' the D.C. Circuit has stated that the EPA must do so. See *Sierra Club* v. *Costle,* 657 F.2d at 326 (''we can think of no sensible interpretation of the statutory words ''best . . . system'' which would not incorporate the amount of air pollution as a relevant factor to be weighed when determining the optimal standard for controlling . . . emissions'').[361] This is consistent with the Court's statements in *Essex Chemical Corp.* v. *Ruckelshaus,* 486 F.2d at 437 that it is necessary to ''[k]eep[] in mind Congress' intent that new plants be controlled to the 'maximum practicable degree' ''.

The final standard of performance will result in meaningful and significant emission reductions of GHG emissions from a new coal-fired steam generating unit. The EPA estimates that a new highly efficient 500 MW coal-fired SCPC meeting the final standard of 1,400 lb CO_2/MWh-g will emit about 354,000 fewer metric tons of CO_2 each year than that new highly efficient unit would have emitted otherwise. That is equivalent to taking about 75,000 vehicles off the road each year[362] and will result in over 14,000,000 fewer metric tons of CO_2 in a 40-year operating life. To emphasize the importance of constructing a highly efficient SCPC unit that includes partial CCS—the highly efficient 500 MW coal-fired SCPC with partial CCS would emit about 675,000 fewer metric tons of CO_2 each year than that from a new, less efficient coal-fired utility boiler with an assumed emission of 1,800 lb CO_2/MWh-g.

For comparison, see Table 12 below which provides the amount of CO_2 emissions captured each year by other CCS projects. These result show that, even though the emission reductions are significant, they are reasonably within the range of emission reductions that are currently being achieved now in existing facilities. For comparison, approximately 60,000,000 metric tons of CO_2 were supplied to U.S. EOR operations in 2013.[363]

TABLE 12—ANNUAL METRIC TONS OF CO_2 CAPTURED (OR PREDICTED TO CAPTURE) FROM CCS PROJECTS AND FROM A MODEL 500 MW PLANT MEETING THE FINAL STANDARD.

Project	CO_2 captured tonnes/year
AES Shady Point	66,000
AES Warrior Run	110,000
Southern Company Plant Barry	165,000
Searles Valley Minerals	270,000
New 500 MW SCPC EGU (1,400 lb CO_2/MWh-g)	354,000
Coffeyville Fertilizer	700,000
Boundary Dam #3	1,000,000
Petra Nova/NRG WA Parish	1,400,000
Dakota Gasification	3,000,000

[357] *http://www.alstom.com/press-centre/2011/5/alstom-announces-sucessful-results-of-mountaineer-carbon-capture-and-sequestration-ccs-project/.* The Boundary Dam facility likewise is operating reliably (see Section V.D.3.a above). See also ''Cost and Performance Baseline for Fossil Energy Plants Volume 1a: Bituminous Coal (PC) and Natural Gas to Electricity, Revision 3'', DOE/NETL–2015/1723 (July 2015) at p. 36 (''[t]he capture and CO_2 compression technologies have commercial operating experience with demonstrated ability for high reliability'').

[358] For additional detail, see the Technical Support Document (TSD)—''Achievability of the Standard for Newly Constructed Steam Generating EGUs''—available in the rulemaking docket.

[359] The cost of the lignite drying equipment is assumed to be low compared to the cost of the carbon capture equipment. Further, pre-drying of the lignite reduces fuel, auxiliary power consumption and other O&M costs. *www.iea-coal.org.uk/documents/83436/9095/Techno-economics-of-modern-pre-drying-technologies-for-lignite-fired-power-plants,-CCC/241.*

[360] Note that the 23 percent increase in expected capital costs and the 23 percent CO_2 capture needed to meet the final standard are coincidental and are not correlated.

[361] *Sierra Club* v. *Costle,* 657 F.2d 298 (D.C. Cir. 1981) was governed by the 1977 CAAA version of the definition of ''standard of performance,'' which revised the phrase ''best system'' to read, ''best technological system.'' The 1990 CAAA deleted ''technological,'' and thereby returned the phrase to how it read under the 1970 CAAA. The *Sierra Club* v. *Costle's* interpretation of this phrase to require consideration of the amount of air emissions remains valid for the phrase ''best system.''

[362] Using U.S. EPA Office of Transportation and Air Quality (OTAQ) estimate of average vehicle emissions of 4.7 tonnes/year.

[363] Greenhouse Gas Reporting Program, data reported as of August 18, 2014.

L. Further Development and Deployment of CCS Technology

Researchers at Carnegie Mellon University (CMU) have studied the history and the technological response to environmental regulations.[364] By examining U.S. research funding and patenting activity over the past century, the CMU researchers found that promulgation of national policy requiring large reductions in power-plant emissions resulted in a significant upswing in inventive activity to develop technologies to reduce those emissions. The researchers found that, following the 1970 Clean Air Act, there was a 10-fold increase in patenting activity directed at improving the SO_2 scrubbers that were needed to comply with stringent federal and state-level standards.

Much like carbon capture scrubbers today, the technology to capture and remove SO_2 from power plant flue gases was new to the industry and was not yet widely deployed at large coal-burning plants when the EPA first promulgated the 1971 standards.

Many of the early Flue Gas Desulfurization (FGD) units did not perform well, as the technology at that time was poorly understood and there was little or no prior experience on coal-fired power plants. In contrast, amine-based capture systems have a much longer history of reliable use at coal-fired plants and other industrial sources. There is also a better understanding of the amine process chemistry and overall process design—and project developers have much sophisticated analytical tools available today than in the 1970s during the development of FGD scrubber technologies.

While R&D efforts were essential to achieving improvements in FGD scrubber technology—and are also very important to improving carbon capture technologies, the influence of regulatory actions that establish commercial markets for advanced technologies cannot be minimized. The existence of national government regulation for SO_2 emissions control stimulated innovation, as shown by the patent analysis following initial SO_2 regulatory requirements for EGU emissions. The study author further found that regulatory stringency appears to be particularly important as a driver of innovation, both in terms of inventive activity and in terms of the communication processes involved in knowledge transfer and diffusion. Further, as electric power generation doubled, the operating and maintenance costs of FGD systems decline to 83 percent of their original level. This finding, which is very much in line with progress ratios determined in other industries, shows that quantifiable technological improvements can be shown to occur solely on the basis of the experience of operating an environmental control technology forced into being by government actions.

M. Technical and Geographic Aspects of Disposition of Captured CO_2

In the following sections of the preamble, we discuss issues associated with the disposition of captured CO_2: the ''S''—sequestration—in CCS. In this section, we review the existing processes, technologies, and geologic conditions that enable successful geologic sequestration (GS). In Section V.N., we discuss in detail the comprehensive, in-place regulatory structure that is currently available to oversee GS projects and assure their safety and effectiveness. Together, these discussions demonstrate that the technical feasibility of GS, another key component of a partial CCS unit, is adequately demonstrated. Sequestration is already well proven. CO_2 has been retained underground for eons in geologic (natural) repositories and the mechanisms by which CO_2 is trapped underground are well understood. The physical and chemical trapping mechanisms, along with the regulatory requirements and safeguards of the Underground Injection Control Program and complementary monitoring and reporting requirements of the GHGRP, together ensure that sequestered CO_2 will remain secure and provide the monitoring to identify and address potential leakage using Safe Drinking Water Act (SDWA) and CAA authorities (see Section V.N of this preamble).[365]

1. Geologic and Geographic Considerations for GS

Geologic sequestration (*i.e.,* long-term containment of a CO_2 stream in subsurface geologic formations) is technically feasible and available throughout most of the United States. GS is based on a demonstrated understanding of the processes that affect CO_2 fate in the subsurface; these processes can vary regionally as the subsurface geology changes. GS occurs through a combination of mechanisms including: (1) Structural and stratigraphic trapping (generally trapping below a low permeability confining layer); (2) residual CO_2 trapping (retention as an immobile phase trapped in the pore spaces of the geologic formation); (3) solubility trapping (dissolution in the in situ formation fluids); (4) mineral trapping (reaction with the minerals in the geologic formation and confining layer to produce carbonate minerals); and (5) preferential adsorption trapping (adsorption onto organic matter in coal and shale).[366] These mechanisms are functions of the physical and chemical properties of CO_2 and the geologic formations into which the CO_2 stream is injected. Subsurface formations suitable for GS of CO_2 captured from affected EGUs are geographically widespread throughout most parts of the United States.

Storage security is expected to increase over time through post-closure, resulting in a decrease in potential risks.[367] This expectation is based in part on a technical understanding of the variety of trapping mechanisms that work to reduce CO_2 mobility over time.[368] In addition, site characterization, site operations, and monitoring strategies can work in combination to promote storage security.

---

[364] See Technical Support Document/ Memorandum ''History Of Flue Gas Desulfurization in the United States'' (July 11, 2015) summarizing the doctoral dissertation of Margaret R. Taylor, ''The Influence of Government Actions on Innovative Activities in the Development of Environmental Technologies to Control Sulfur Dioxide Emissions from Stationary Sources,'' MA dissertation submitted to the Carnegie Institute of Technology, Carnegie Mellon University in partial fulfillment of the requirements for the degree of Doctor of Philosophy in Engineering and Public Policy, Pittsburgh, PA, January 2001.

[365] See also *Carbon Sequestration Council and Southern Company Services* v. *EPA,* No. 14–1406 (D.C. Cir. June 2, 2015) at *10 (''[c]arbon capture and storage is an emerging climate change mitigation program that involves capturing carbon dioxide from industrial sources, compressing it into a 'supercritical fluid,' and injecting that fluid underground for the purposes of geologic sequestration, with the goal of preventing the carbon from reentering the atmosphere. Because the last of these steps—geologic sequestration of the supercritical carbon dioxide—involves that injection of fluid into underground wells, it is subject to regulation under the Safe Drinking Water Act'').

[366] See, *e.g.,* USEPA. 2008. Vulnerability Evaluation Framework for Geologic Sequestration of Carbon Dioxide.

[367] Report of the Interagency Task Force on Carbon Capture and Storage (August 2010), page 47.

[368] See, *e.g.,* Intergovernmental Panel on Climate Change. (2005). Special Report on Carbon Dioxide Capture and Storage.

The effectiveness of long-term trapping of CO_2 has been demonstrated by natural analogs in a range of geologic settings where CO_2 has remained trapped for millions of years.[369] For example, CO_2 has been trapped for more than 65 million years in the Jackson Dome, located near Jackson, Mississippi.[370] Other examples of natural CO_2 sources include Bravo Dome and McElmo Dome in Colorado and New Mexico, respectively. These natural storage sites are themselves capable of holding volumes of CO_2 that are larger than the volume of CO_2 expected to be captured from a fossil fuel-fired EGU. In 2010, the Department of Energy (DOE) estimated current CO_2 reserves of 594 million metric tons at Jackson Dome, 424 million metric tons at Bravo Dome, and 530 million metric tons at McElmo Dome.[371]

GS is feasible in different types of geologic formations including deep saline formations (formations with high salinity formation fluids) or in oil and gas formations, such as where injected CO_2 increases oil production efficiency through a process referred to as enhanced oil recovery (EOR). Both deep saline and oil and gas formation types are widely available in the United States. The geographic availability of deep saline formations and EOR is shown in Figure 1 below.[372] As shown in the figure, there are 39 states for which onshore and offshore deep saline formation storage capacity has been identified.[373] EOR operations are currently being conducted in 12 states. An additional 17 states have geology that is amenable to EOR operations. Figure 1 also shows areas that are within 100 kilometers (62 miles) of where storage capacity has been identified.[374] There are 10 states with operating CO_2 pipelines and 18 states that are within 100 kilometers (62 miles) of an active EOR location.

CO_2 may also be used for other types of enhanced recovery, such as for natural gas production. Reservoirs such as unmineable coal seams also offer the potential for geologic storage.[375] Enhanced coalbed methane recovery is the process of injecting and storing CO_2 in unmineable coal seams to enhance methane recovery. These operations take advantage of the preferential chemical affinity of coal for CO_2 relative to the methane that is naturally found on the surfaces of coal. When CO_2 is injected, it is adsorbed to the coal surface and releases methane that can then be captured and produced. This process effectively ''locks'' the CO_2 to the coal, where it remains stored. DOE has identified over 54 billion metric tons of potential CO_2 storage capacity in unmineable coal across 21 states.[376] The availability of unmineable coal seams is shown in Figure 1 below.

As discussed below in Section M.7, a few states do not have geologic conditions suitable for GS, or may not be located in proximity to these areas. However, in some cases, demand in those states can be served by coal-fired power plants located in areas suitable for GS, and in other cases, coal-fired power plants are unlikely to be built in those areas for other reasons, such as the lack of available coal or state law prohibitions and restrictions against coal-fired power plants.[377]

[369] Holloway, S., J. Pearce, V. Hards, T. Ohsumi, and J. Gale. 2007. Natural Emissions of CO_2 from the Geosphere and their Bearing on the Geological Storage of Carbon Dioxide. Energy 32: 1194–1201.

[370] Intergovernmental Panel on Climate Change. (2005). Special Report on Carbon Dioxide Capture and Storage.

[371] DiPietro, P., Balash, P. & M. Wallace. A Note on Sources of CO_2 Supply for Enhanced-Oil Recovery Operations. SPE Economics & Management. April 2012.

[372] A color version of the figure, which readers may find easier to view, can be found in the technical support document on geographic availability in the rulemaking docket.

[373] Alaska is not shown in Figure 1; it has deep saline formation storage capacity, geology amenable to EOR operations, and potential GS capacity in unmineable coal seams.

[374] The distance of 100 kilometers reflects assumptions in DOE–NETL cost estimates which the EPA used for cost estimation purposes. See ''Carbon Dioxide and Transport and Storage Costs in NETL Studies'', DOE/NETL–2014/1653 (May 2014).

[375] Other types of opportunities include organic shales and basalt.

[376] The United States 2012 Carbon Utilization and Storage Atlas, Fourth Edition, U.S. Department of Energy, Office of Fossil Energy, National Energy Technology Laboratory (NETL).

[377] Similarly, as discussed below, the U.S. territories lack available coal, do not currently have coal-fired power plants, and, as a result, are not expected to see new coal-fired power plants. Hawaii is not expected to constructed new coal plants as it intends to utilize 100 percent renewable energy sources by 2050.

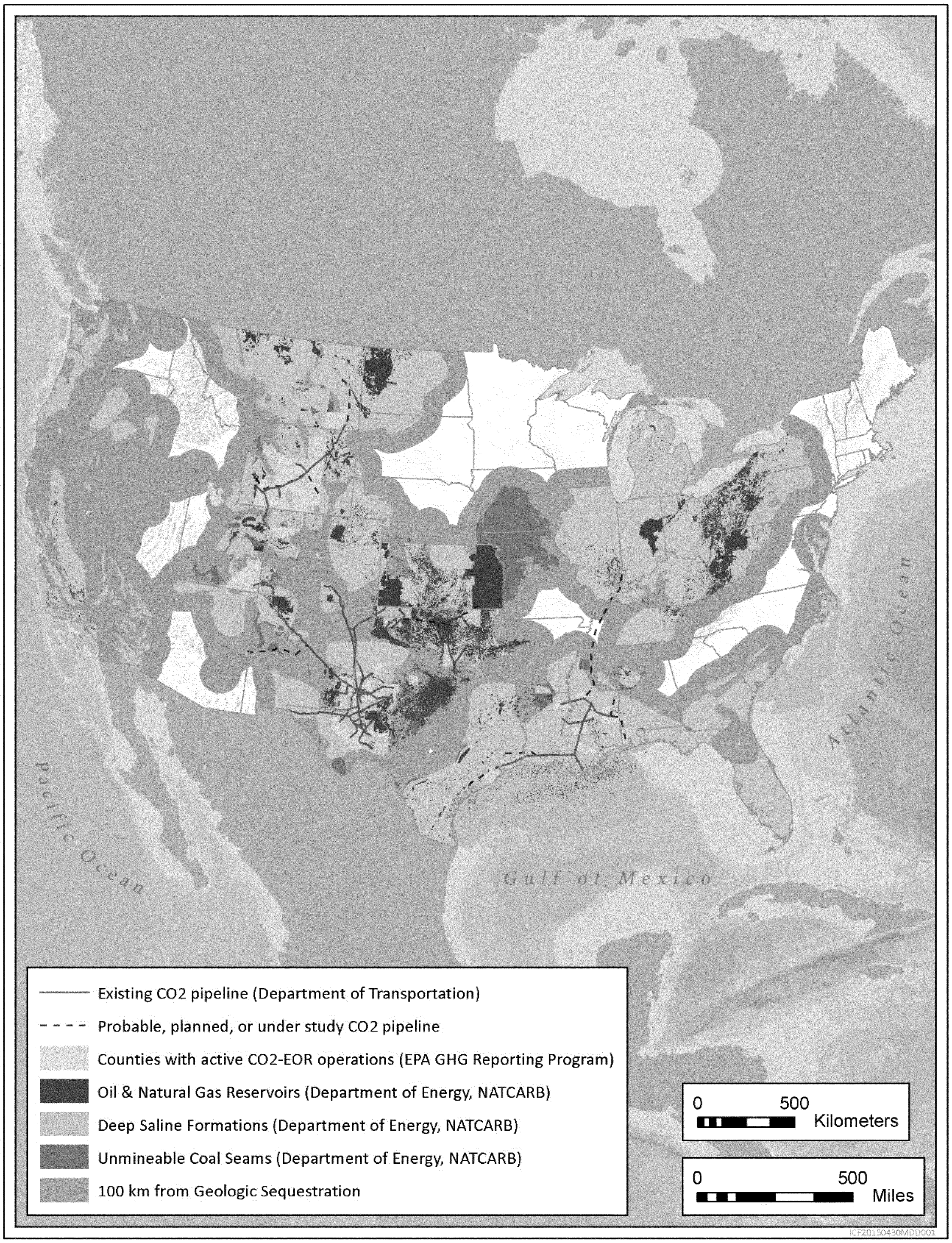


Figure 1: Geologic Sequestration in the Continental United States

Figure 2 – Electrical Transmission Lines across the Continental United States[378]

2. Availability of Geologic Sequestration in Deep Saline Formations

The DOE and the United States Geological Survey (USGS) have independently conducted preliminary analyses of the availability and potential CO_2 sequestration capacity of deep saline formations in the United States. DOE estimates are compiled by the DOE's National Carbon Sequestration Database and Geographic Information System (NATCARB) using volumetric models and published in a Carbon Utilization and Storage Atlas.[379] DOE estimates that areas of the United States

[378] Ventyx Velocity Suite Online. April 2015.

[379] The United States 2012 Carbon Utilization and Storage Atlas, Fourth Edition, U.S. Department of Energy, Office of Fossil Energy, National Energy Technology Laboratory (NETL).

with appropriate geology have a sequestration potential of at least 2,035 billion metric tons of CO_2 in deep saline formations. According to DOE and as noted above, at least 39 states have geologic characteristics that are amenable to deep saline GS in either onshore or offshore locations. In 2013, the USGS completed its evaluation of the technically accessible GS resources for CO_2 in U.S. onshore areas and state waters using probabilistic assessment.[380] The USGS estimates a mean of 3,000 billion metric tons of subsurface CO_2 sequestration potential, including saline and oil and gas reservoirs, across the basins studied in the United States.

The DOE has created a network of seven Regional Carbon Sequestration Partnerships (RCSPs) to deploy large-scale field projects in different geologic settings across the country to demonstrate that GS can be achieved safely, permanently, and economically at large scales. Collectively, the seven RCSPs represent regions encompassing 97 percent of coal-fired CO_2 emissions, 97 percent of industrial CO_2 emissions, 96 percent of the total land mass, and essentially all the geologic sequestration sites in the United States potentially available for GS.[381] The seven partnerships include more than 400 organizations spanning 43 states (and four Canadian provinces).[382] RCSP project objectives are to inject at least one million metric tons of CO_2. In April 2015, DOE announced that CCS projects supported by the department have safely and permanently stored 10 million metric tons of CO_2.[383]

Eight RCSP ''Development Phase'' projects have been initiated and five of the eight projects are injecting or have completed CO_2 injection into deep saline formations. Three of these projects have already injected more than one million metric tons each, and one, the Cranfield Site, injected over eight million metric tons of CO_2 between 2009 and 2013.[384] Various types of technologies for monitoring CO_2 in the subsurface and air have been employed at these projects, such as seismic methods (crosswell seismic, 3–D and 4–D seismic, and vertical seismic profiling), atmospheric CO_2 monitoring, soil gas sampling, well and formation pressure monitoring, and surface and ground water monitoring.[385] No CO_2 leakage has been reported from these sites, which further supports the availability of effective GS.

3. Availability of CO_2 Storage via EOR

Although the determination that the BSER is adequately demonstrated and the regulatory impact analysis for this rule relies on GS in deep saline formations, the EPA also recognizes the potential for securely sequestering CO_2 via EOR.

EOR is a technique that is used to increase the production of oil. Approaches used for EOR include steam injection, injection of specific fluids such as surfactants and polymers, and gas injection including nitrogen and CO_2. EOR using CO_2, sometimes referred to as ''CO_2 flooding'' or CO_2-EOR, involves injecting CO_2 into an oil reservoir to help mobilize the remaining oil to make it more amenable for recovery. The crude oil and CO_2 mixture is then recovered and sent to a separator where the crude oil is separated from the gaseous hydrocarbons, native formation fluids, and CO_2. The gaseous CO_2-rich stream then is typically dehydrated, purified to remove hydrocarbons, re-compressed, and re-injected into the reservoir to further enhance oil recovery. Not all of the CO_2 injected into the oil reservoir is recovered and re-injected. As the CO_2 moves from the injection point to the production well, some of the CO_2 becomes trapped in the small pores of the rock, or is dissolved in the oil and water that is not recovered. The CO_2 that remains in the reservoir is not mobile and becomes sequestered.

The amount of CO_2 used in an EOR project depends on the volume and injectivity of the reservoir that is being flooded and the length of time the EOR project has been in operation. Initially, all of the injected CO_2 is newly received. As discussed above, as the project matures, some CO_2 is recovered with the oil and the recovered CO_2 is separated from the oil and recycled so that it can be re-injected into the reservoir in addition to new CO_2 that is received. If an EOR operator will not require the full volume of CO_2 available from an EGU, the EGU has other options such as sending the CO_2 to other EOR operators, or sending it to deep saline formation GS facilities.

CO_2 used for EOR may come from anthropogenic or natural sources. The source of the CO_2 does not impact the effectiveness of the EOR operation. CO_2 capture, treatment and processing steps provide a concentrated stream of CO_2 in order to meet the needs of the intended end use. CO_2 pipeline specifications of the U.S. Department of Transportation Pipeline Hazardous Materials Safety Administration found at 49 CFR part 195 (Transportation of Hazardous Liquids by Pipeline) apply regardless of the source of the CO_2 and take into account CO_2 composition, impurities, and phase behavior. Additionally, EOR operators and transport companies have specifications related to the composition of the CO_2 stream. The regulatory requirements and company specifications ensure EOR operators receive a known and consistent CO_2 stream.

EOR has been successfully used at numerous production fields throughout the United States to increase oil recovery. The oil industry in the United States has over 40 years of experience with EOR. An oil industry study in 2014 identified more than 125 EOR projects in 98 fields in the United States.[386] More than half of the projects evaluated in the study have been in operation for more than 10 years, and many have been in operation for more than 30 years. This experience provides a strong foundation for demonstrating successful CO_2 injection and monitoring technologies, which are needed for safe and secure GS (see Section N below) that can be used for deployment of CCS across geographically diverse areas.

Currently, 12 states have active EOR operations and most have developed an extensive CO_2 infrastructure, including pipelines, to support the continued operation and growth of EOR. An additional 18 states are within 100 kilometers (62 miles) of current EOR operations. See Figure 1 above. The vast majority of EOR is conducted in oil reservoirs in the Permian Basin, which extends through southwest Texas and southeast New Mexico. States where EOR is utilized include Alabama, Colorado, Louisiana, Michigan,

[380] U.S. Geological Survey Geologic Carbon Dioxide Storage Resources Assessment Team, 2013, National assessment of geologic carbon dioxide storage resources—Results: U.S. Geological Survey Circular 1386, p. 41, *http://pubs.usgs.gov/circ/1386/*.

[381] *http://energy.gov/fe/science-innovation/carbon-capture-and-storage-research/regional-partnerships*.

[382] *http://energy.gov/fe/science-innovation/carbon-capture-and-storage-research/regional-partnerships*.

[383] *http://energy.gov/articles/milestone-energy-department-projects-safely-and-permanently-store-10-million-metric-tons*.

[384] U.S. Department of Energy, National Energy Technology Laboratory, Project Facts, Southeast Regional Carbon Sequestration Partnership—Development Phase, Cranfield Site and Citronelle Site Projects, NT42590, October 2013. Available at: *http://www.netl.doe.gov/publications/factsheets/project/NT42590.pdf*.

[385] A description of the types of monitoring technologies employed at RCSP projects can be found here: *http://www.netl.doe.gov/research/coal/carbon-storage/carbon-storage-infrastructure/regional-partnership-development-phase-iii*.

[386] Koottungal, Leena, 2014, 2014 Worldwide EOR Survey, Oil & Gas Journal, Volume 112, Issue 4, April 7, 2014 (corrected tables appear in Volume 112, Issue 5, May 5, 2014).

Mississippi, New Mexico, Oklahoma, Texas, Utah, and Wyoming. Several commenters raised concerns about the volume of CO_2 used in EOR projects relative to the scale of EGU emissions and the demand for CO_2 for EOR projects. At the project level, the volume of CO_2 already injected for EOR and the duration of operations are of similar magnitude to the duration and volume of CO_2 expected to be captured from fossil fuel-fired EGUs. The volume of CO_2 used in EOR operations can be large (*e.g.,* 55 million tons of CO_2 were stored in the SACROC unit in the Permian Basin over 35 years), and operations at a single oil field may last for decades, injecting into multiple parts of the field.[387] According to data reported to the EPA's GHGRP, approximately 60 million metric tons of CO_2 were supplied to EOR in the United States in 2013.[388] Approximately 70 percent of this total CO_2 supplied was produced from natural (geologic) CO_2 sources and approximately 30 percent was captured from anthropogenic sources.[389]

A DOE-sponsored study has analyzed the geographic availability of applying EOR in 11 major oil producing regions of the United States and found that there is an opportunity to significantly increase the application of EOR to areas outside of current operations.[390] DOE-sponsored geologic and engineering analyses show that expanding EOR operations into areas additional to the capacity already identified and applying new methods and techniques over the next 20 years could utilize 18 billion metric tons of anthropogenic CO_2 and increase total oil production by 67 billion barrels. The study found that one of the limitations to expanding CO_2 use in EOR is the lack of availability of CO_2 in areas where reservoirs are most amenable to CO_2 flooding.[391] DOE's Carbon Utilization and Storage Atlas identifies 29 states with oil reservoirs amenable to EOR, 12 of which currently have active EOR operations. A comparison of the current states with EOR operations and the states with potential for EOR shows that an opportunity exists to expand the use of EOR to regions outside of current areas. The availability of anthropogenic CO_2 in areas outside of current sources could drive new EOR projects by making more CO_2 locally available.

Some commenters raised concerns that data are extremely limited on the extent to which EOR operations permanently sequester CO_2, and the efficacy of long term storage, or that the EOR industry does not have the requisite experience with and technical knowledge of long-term CO_2 sequestration. The EPA disagrees with these commenters. Several EOR sites, which have been operated for years to decades, have been studied to evaluate the viability of safe and secure long-term sequestration of injected CO_2. Examples are identified below.

CO_2 has been injected in the SACROC Unit in the Permian basin since 1972 for EOR purposes. One study evaluated a portion of this project, and estimated that the injection operations resulted in final sequestration of about 55 million tons of CO_2.[392] This study used modeling and simulations, along with collection and analysis of seismic surveys, and well logging data, to evaluate the ongoing and potential CO_2 trapping occurring through various mechanisms. The monitoring at this site demonstrated that CO_2 can become trapped in geologic formations. In a separate study in the SACROC Unit, the Texas Bureau of Economic Geology conducted an extensive groundwater sampling program to look for evidence of CO_2 leakage in the shallow freshwater aquifers. No evidence of leakage was detected.[393]

The International Energy Agency Greenhouse Gas Programme conducted an extensive monitoring program at the Weyburn oil field in Saskatchewan between 2000 and 2010 (the site receiving CO_2 captured by the Dakota Gasification synfuel plant discussed in Section V.E.2.a above). During that time over 16 million metric tons of CO_2 were safely sequestered as evidenced by soil gas surveys, shallow groundwater monitoring, seismic surveys and wellbore integrity testing. An extensive shallow groundwater monitoring program revealed no significant changes in water chemistry that could be attributed to CO_2 storage operations.[394] The International Energy Agency Greenhouse Gas Programme developed a best practices manual for CO_2 monitoring at EOR sites based on the comprehensive analysis of surface and subsurface monitoring methods applied over the 10 years.[395]

The Texas Bureau of Economic Geology also has been testing a wide range of surface and subsurface monitoring tools and approaches to document sequestration efficiency and sequestration permanence at the Cranfield oilfield in Mississippi (see Section L.1 above).[396] As part of a DOE Southeast Regional Carbon Sequestration Partnership study, Denbury Resources injected CO_2 into a depleted oil and gas reservoir at a rate greater than 1.2 million tons/year. Texas Bureau of Economic Geology is currently evaluating the results of several monitoring techniques employed at the Cranfield project and preliminary findings indicate no impact to groundwater.[397] The project also demonstrates the availability and effectiveness of many different monitoring techniques for tracking CO_2 underground and detecting CO_2 leakage to ensure CO_2 remains safely sequestered.

As discussed in Section M.1 above and as shown in Figure 1, the United States has widespread potential for storage, including in deep saline formations and oil and gas formations. However, some commenters maintained that the EPA's information regarding availability of GS sites is overly general and ignores important individual considerations. A number of commenters, for example, maintained that site conditions often make monitoring difficult or impossible, so

[387] Han, Weon S., McPherson, B J., Lichtner, P C., and Wang, F P. ''Evaluation of CO_2 trapping mechanisms at the SACROC northern platform, Permian basin, Texas, site of 35 years of CO_2 injection.'' American Journal of Science 310. (2010): 282–324.

[388] Greenhouse Gas Reporting Program, data reported as of August 18, 2014.

[389] Greenhouse Gas Reporting Program, data reported as of August 18, 2014.

[390] ''Improving Domestic Energy Security and Lowering CO_2 Emissions with ''Next Generation'' CO_2-Enhanced Oil Recovery'', Advanced Resources International, Inc. (ARI), 2011. Available at: *http://www.netl.doe.gov/research/energy-analysis/publications/details?pub=df02ffba-6b4b-4721-a7b4-04a505a19185*.

[391] ''Improving Domestic Energy Security and Lowering CO_2 Emissions with ''Next Generation'' CO_2-Enhanced Oil Recovery'', Advanced Resources International, Inc. (ARI), 2011. Available at: *http://www.netl.doe.gov/research/energy-analysis/publications/details?pub=df02ffba-6b4b-4721-a7b4-04a505a19185*.

[392] Han, Weon S., McPherson, B J., Lichtner, P C., and Wang, F P. ''Evaluation of CO_2 trapping mechanisms at the SACROC northern platform, Permian basin, Texas, site of 35 years of CO_2 injection.'' American Journal of Science 310. (2010): 282–324.

[393] Romanak, K.D., Smyth, R.C., Yang, C., and Hovorka, S., Detection of anthropogenic CO_2 in dilute groundwater: field observations and geochemical modeling of the Dockum aquifer at the SACROC oilfield, West Texas, USA: presented at the 9th Annual Conference on Carbon Capture & Sequestration, Pittsburgh, PA, May 10–13, 2010. GCCC Digital Publication Series #10–06.

[394] Roston, B., and S. Whittaker (2010), 10+ years of the IEA–GHG Weyburn-Midale CO_2 monitoring and storage project; success and lessons learned from multiple hydrogeological investigations, to be published in Energy Procedia, Elsevier, Proceedings of 10th International Conference on Greenhouse Gas Control Technologies, IEA Greenhouse Gas Programme, Amsterdam, The Netherlands.

[395] Hitchon, B. (Editor), 2012, Best Practices for Validating CO_2 Geological Storage: Geoscience Publishing, p. 353.

[396] *http://www.beg.utexas.edu/gccc/cranfield.php.*

[397] *http://www.beg.utexas.edu/gccc/cranfield.php.*

that sites are not available as a practical matter.[398] Commenter American Electric Power pointed to its own experience in siting monitoring wells for its pilot plant Mountaineer CCS project, which involved protracted time and expense to eventually site monitoring wells.[399] Other commenters noted significant geographic disparity in GS site availability, claiming absence of sites in southeastern areas of the country.[400]

Project- and site-specific factors do influence where CO_2 can be safely sequestered. However, as outlined above, there is widespread potential for GS in the United States. If an area does not have a suitable GS site, EGUs can either transport CO_2 to GS sites via CO_2 pipelines (see Section M.5 below), or they may choose to locate their units closer to GS sites and provide electric power to customers through transmission lines (see Figure 2 and Section M.7). In addition, there are alternative means of complying with the final standards of performance that do not necessitate use of partial CCS, so any siting difficulties based on lack of a CO_2 repository would be obviated. See *Portland Cement Ass'n* v. *EPA,* 665 F. 3d 177, 191 (D.C. Cir. 2011), holding that the EPA could adopt section 111 standards of performance based on the performance of a kiln type that kilns of older design would have great difficulty satisfying, since, among other things, there were alternative methods of compliance available should a new kiln of this older design be built.

4. Alternatives to Geologic Sequestration

Potential alternatives to sequestering CO_2 in geologic formations are emerging. These relatively new potential alternatives may offer the opportunity to offset the cost of CO_2 capture. For example, captured anthropogenic CO_2 may be stored in solid carbonate materials such as precipitated calcium carbonate (PCC) or magnesium or calcium carbonate, bauxite residue carbonation, and certain types of cement through mineralization. PCC is produced through a chemical reaction process that utilizes calcium oxide (quicklime), water, and CO_2. Likewise, the combination of magnesium oxide and CO_2 results in a precipitation reaction where the CO_2 becomes mineralized. The carbonate materials produced can be tailored to optimize performance in specific industrial and commercial applications. These carbonate materials have been used in the construction industry and, more recently and innovatively, in cement production processes to replace Portland cement.

The Skyonics Skymine project, which opened its demonstration project in October 2014, is an example of captured CO_2 being used in the production of carbonate products. This plant converts CO_2 into commercial products. It captures over 75,000 tons of CO_2 annually from a San Antonio, Texas, cement plant and converts the CO_2 into other products, including sodium carbonate, sodium bicarbonate, hydrochloric acid and bleach.[401]

A few commenters suggested that CO_2 utilization technologies alternative to GS are being commercialized, and that these should be included as compliance options for this rule. The rule generally requires that captured CO_2 be either injected on-site for geologic sequestration or transferred offsite to a facility reporting under 40 CFR subpart RR. The EPA does not believe that the emerging technologies just discussed are sufficiently advanced to unqualifiedly structure this final rule to allow for their use. Nor are there plenary systems of regulatory control and GHG reporting for these approaches, as there are for geologic sequestration. Nonetheless, as stated above, these technologies not only show promise, but could potentially be demonstrated to show permanent storage of CO_2.

In the January 2014 proposal, the EPA noted that it would need to adopt a mechanism to evaluate these alternative technologies before any could be used in lieu of geologic sequestration. 79 FR at 1484. The EPA is establishing such a mechanism in this final rule. See § 60.5555(g). The rule provides for a case-by-case adjudication by the EPA of applications seeking to demonstrate to the EPA that a non-geologic sequestration technology would result in permanent confinement of captured CO_2 from an affected EGU. The criteria to be addressed in the application, and evaluated by the EPA, are drawn from CAA section 111(j), which provides an analogous mechanism for case-by-case approval of innovative technological systems of continuous emission reduction which have not been adequately demonstrated. Applicants would need to demonstrate that the proposed technology would operate effectively, and that captured CO_2 would be permanently stored. Applicants must also demonstrate that the proposed technology will not cause or contribute to an unreasonable risk to public health, welfare or safety. In evaluating applications, the EPA may conduct tests itself or require the applicant to conduct testing in support of its application. Any application would be publicly noticed, and the EPA would solicit comment on the application and on intended action the EPA might take. The EPA could also provide a conditional approval of an application on operating results from a proscribed period. The EPA could also terminate an approval, including a termination based on operating results calling into question a technology's effectiveness.

As noted at proposal, given the unlikelihood of new coal-fired EGUs being constructed, the EPA does not expect there to be many (if any) applications for use of non-geologic sequestration technology. 79 FR at 1484.

5. Availability of Existing or Planned CO_2 Pipelines

CO_2 pipelines are the most economical and efficient method of transporting large quantities of CO_2.[402] CO_2 has been transported via pipelines in the United States for nearly 40 years. Over this time, the design, construction, operation, and safety requirements for CO_2 pipelines have been proven, and the U.S. CO_2 pipeline network has been safely used and expanded. The Pipeline and Hazardous Materials Safety Administration (PHMSA) reported that in 2013 there were 5,195 miles of CO_2 pipelines operating in the United States. This represents a seven percent increase in CO_2 pipeline miles over the previous year and a 38 percent increase in CO_2 pipeline miles since 2004.[403]

Some commenters argued that the existing CO_2 pipeline capacity is not adequate and that CO_2 pipelines are not available in a majority of the United States.

The EPA does not agree. The CO_2 pipeline network in the United States has almost doubled in the past ten years in order to meet growing demands for CO_2 for EOR. CO_2 transport companies have recently proposed initiatives to expand the CO_2 pipeline network. Several hundred miles of dedicated CO_2 pipeline are under construction, planned, or proposed, including

[398] Comments of Southern Co., p. 38 (Docket entry: EPA–HQ–OAR–2013–0495–10095).

[399] Comments of AEP pp. 93, 96 (Docket entry: EPA–HQ–OAR–2013–0495–10618).

[400] Comments of Duke Energy, pp. 24–5 Docket entry: EPA–HQ–OAR–2013–0495–9426); UARG, pp. 53, 57 (Docket entry: EPA–HQ–OAR–2013–0495–9666) citing Cichanowicz (2012).

[401] *http://skyonic.com/technologies/skymine.*

[402] Report of the Interagency Task Force on Carbon Capture and Storage (August 2010), page 36.

[403] ''Annual Report Mileage for Hazardous Liquid or Carbon Dioxide Systems'', U.S. Pipeline and Hazardous Materials Safety Administration, March 2, 2015. Available at: *http://www.phmsa.dot.gov/pipeline/library/data-stats.*

projects in Colorado, Louisiana, Montana, New Mexico, Texas, and Wyoming.

Examples are identified below.

Kinder Morgan has reported several proposed pipeline projects including the proposed expansion of the existing Cortez CO_2 pipeline, crossing Colorado, New Mexico, and Texas, to increase the CO_2 transport capacity from 1.35 billion cubic feet per day (Bcf/d) to 1.7 Bcf/d, to support the expansion of CO_2 production capacity at the McElmo Dome production facility in Colorado. The Cortez pipeline expansion is expected to be placed into service in 2015.[404]

Denbury reported that the company utilized approximately 70 million cubic feet per day of anthropogenic CO_2 in 2013 and that an additional approximately 115 million cubic feet per day of anthropogenic CO_2 may be utilized in the future from currently planned or future construction of facilities and associated pipelines in the Gulf Coast region.[405] Denbury also initiated transport of CO_2 from a Wyoming natural gas processing plant in 2013 and reported transporting approximately 22 million cubic feet per day of CO_2 in 2013 from that plant alone.[406]

Denbury completed the final section of the 325-mile Green Pipeline for transporting CO_2 from Donaldsonville, Louisiana, to EOR oil fields in Texas.[407] Denbury completed construction and commenced operation of the 232-mile Greencore Pipeline in 2013; the Greencore pipeline transports CO_2 to EOR fields in Wyoming and Montana.[408]

A project being constructed by NRG and JX Nippon Oil & Gas Exploration (Petra Nova) would capture CO_2 from a power plant in Fort Bend County, Texas for transport to EOR sites in Jackson County, Texas through an 82-mile CO_2 pipeline.[409] The project is anticipated to commence operation in 2016.[410]

Some commenters suggested that there may be challenges associated with the safety of transporting supercritical CO_2 over long distances, or that the EPA did not adequately consider the potential non-air environmental impacts of the construction of CO_2 pipelines.

The EPA has carefully evaluated the safety of pipelines used to transport captured CO_2 and determined that pipelines can indeed convey captured CO_2 to sequestration sites with certainty and provide full protection of human health and the environment. 76 FR at 48082–83 (Aug. 8, 2011); 79 FR 352, 354 (Jan. 3, 2014). Existing and new CO_2 pipelines are comprehensively regulated by the Department of Transportation's Pipeline Hazardous Material Safety Administration. The regulations govern pipeline design, construction, operation and maintenance, and emergency response planning. See generally 49 CFR 195.2. Additional regulations address pipeline integrity management by requiring heightened scrutiny to assure the quality of pipeline integrity in areas with a higher potential for adverse consequences. See 49 CFR 195.450 and 195.452. On-site pipelines are not subject to the Department of Transportation standards, but rather adhere to the Pressure Piping standards of the American Society of Mechanical Engineers (ASME B31), which the EPA has found would ensure that piping and associated equipment meet certain quality and safety criteria sufficient to prevent releases of CO_2, such that certain additional requirements were not necessary (See 79 FR 358–59 (Jan. 3, 2014)).[411] These existing controls over CO_2 pipelines assure protective management, guard against releases, and assure that captured CO_2 will be securely conveyed to a sequestration site.

6. States With Emission Standards That Would Require CCS

Several states have established emission performance standards or other measures to limit emissions of GHGs from new EGUs that are comparable to or more stringent than the final standard in this rulemaking. For example, in September 2006, California Governor Schwarzenegger signed into law Senate Bill 1368. The law limits long-term investments in base load generation by the state's utilities to power plants that meet an emissions performance standard jointly established by the California Energy Commission and the California Public Utilities Commission. The Energy Commission has designed regulations that establish a standard for new and existing base load generation owned by, or under long-term contract to publicly owned utilities, of 1,100 lb CO_2/MWh.

In May 2007, Washington Governor Gregoire signed Substitute Senate Bill 6001, which established statewide GHG emissions reduction goals, and imposed an emission standard that applies to any base load electric generation that commenced operation after June 1, 2008 and is located in Washington, whether or not that generation serves load located within the state. Base load generation facilities must initially comply with an emission limit of 1,100 lb CO_2/MWh.

In July 2009, Oregon Governor Kulongoski signed Senate Bill 101, which mandated that facilities generating base load electricity, whether gas- or coal-fired, must have emissions equal to or less than 1,100 lb CO_2/MWh, and prohibited utilities from entering into long-term purchase agreements for base load electricity with out-of-state facilities that do not meet that standard.

In 2012 New York established emission standards of CO_2 at 925 lb CO_2/MWh for new and expanded base load fossil fuel-fired plants.

In May 2007, Montana Governor Schweitzer signed House Bill 25, adopting a CO_2 emissions performance standard for EGUs in the state. House Bill 25 prohibits the state Public Utility Commission from approving new EGUs primarily fueled by coal unless a minimum of 50 percent of the CO_2 produced by the facility is captured and sequestered.

On January 12, 2009, Illinois Governor Blagojevich signed Senate Bill 1987, the Clean Coal Portfolio Standard Law. The legislation establishes emission standards for new power plants that use coal as their primary feedstock. From 2009–2015, new coal-fueled power plants must capture and store 50 percent of the carbon emissions that the facility would otherwise emit; from 2016–2017, 70 percent must be captured and stored; and after 2017, 90 percent must be captured and stored.

7. Coal-by-Wire

In addition, as discussed in the proposal, electricity demand in states

[404] "Form 10–K: Annual Report Pursuant to Section 13 or 15(d) of the Security and Exchange Act of 1934, For the Fiscal Year Ended December 31, 2014", Kinder Morgan, February 2015. Available at: *http://ir.kindermorgan.com/sites/kindermorgan.investorhq.businesswire.com/files/report/additional/KMI–2014–10K_Final.pdf.*

[405] "2013 Annual Report", Denbury, April 2014. Available at *http://www.denbury.com/files/doc_financials/2013/Denbury_Final_040814.pdf.*

[406] "CO_2 Sources", Denbury, 2015. Available at: *http://www.denbury.com/operations/rocky-mountain-region/co2-sources-and-pipelines/default.aspx.*

[407] *http://www.denbury.com/operations/gulf-coast-region/Pipelines/default.aspx.*

[408] "CO_2 Pipelines", Denbury, 2014. Available at: *http://www.denbury.com/operations/rocky-mountain-region/COsub2-sub-Pipelines/default.aspx.*

[409] "The West Ranch CO_2-EOR Project, NRG Fact Sheet", NRG, 2014. Available at: *www.nrg.com/documents/business/pla-2014-west-ranch-fact-sheet.pdf.*

[410] "WA Parish Carbon Capture Project", NRG, 2015. Available at: *www.nrg.com/sustainability/strategy/enhance-generation/carbon-capture/wa-parish-ccs-project/.*

[411] See the B31 Code for pressure piping, developed by the American Society of Mechanical Engineers, Pipeline Transportation Systems for liquid hydrocarbons and other liquids.

that may not have geologic sequestration sites may be served by coal-fired electricity generation built in nearby areas with geologic sequestration, and this electricity can be delivered through transmission lines. This method, known as ''coal-by-wire,'' has long been used in the electricity sector because siting a coal-fired power plant near the coal mine and transmitting the generation long distances to the load area is generally less expensive than siting the plant near the load area and shipping the coal long distances.

For example, we noted in the proposal that there are many examples where coal-fired power generated in one state is used to supply electricity in other states. In the proposal we specifically noted that historically nearly 40 percent of the power for the City of Los Angeles was provided from two coal-fired power plants located in Arizona and Utah and Idaho Power, which serves customers in Idaho and Eastern Oregon, meets its demand in part from coal-fired power plants located in Wyoming and Nevada. 79 FR at 1478.

In the Technical Support Document on Geographic Availability (Geographic Availability TSD), we explore in greater detail the issue of coal-by-wire and the ability of demand in areas without geologic sequestration to be served by coal generation located in areas that have access to geologic sequestration. Figure 1 of this preamble (a color version of which is provided as Figure 1 of the Geographic Availability TSD) depicts areas of the country with: (1) existing CO_2 pipeline; (2) probable, planned, or under study CO_2 pipeline; (3) counties with active CO_2-EOR operations; (4) oil and natural gas reservoirs; (5) deep saline formations; (6) unmineable coal seams; and (7) areas 100 kilometers from geologic sequestration. As demonstrated by Figure 1, the vast majority of the country has existing or planned CO_2 pipeline, active CO_2-EOR operations, the necessary geology for CO_2 storage, or is within 100 kilometers of areas with geologic sequestration.[412] A review of Figure 1 indicates limited areas that do not fall into these categories.

As an initial matter, we note that the data included in Figure 1 is a conservative outlook of potential areas available for the development of CO_2 storage in that we include only areas that have been assessed to date. Portions of the United States—such as the State of Minnesota—have not yet been assessed and thus are depicted as not having geological formations suitable for CO_2 storage, even though assessment could in fact reveal additional formations.[413]

As one considers the areas on the map depicted in Figure 1 that fall outside of the above enumerated categories, in many instances, we find areas with low population density, areas that are already served by transmission lines that could deliver coal-by-wire, and/or areas that have made policy or other decisions not to pursue a resource mix that includes coal. In many of these areas, utilities, electric cooperatives, and municipalities have a history of joint ownership of coal-fired generation outside the region or contracting with coal and other generation in outside areas to meet their demand. Some of the relevant areas are in RTOs[414] which engage in planning across the RTO, balancing supply and demand in real time throughout the RTO. Accordingly, generating resources in one part of the RTO such as a coal generator can serve load in other parts of the RTO, as well as load outside of the RTO. As we consider each of these geographic areas in the Geographic Availability TSD, we make key points as to why this final rule does not negatively impact the ability of these regions to access new coal generation to the extent that coal is needed to supply demand and/or those regions want to include new coal-fired generation in their resource mix.

N. Final Requirements for Disposition of Captured CO_2

This section discusses the different regulatory components, already in place, that assure the safety and effectiveness of GS. This section, by demonstrating that GS is already covered by an effective regulatory structure, complements the analysis of the technical feasibility of GS contained in Sec. V.M. Together, these sections affirm that the technical feasibility of GS is adequately demonstrated.

In 2010, the EPA finalized an effective and coherent regulatory framework to ensure the long-term, secure and safe storage of large volumes of CO_2. The EPA developed these Underground Injection Control (UIC) Class VI well regulations under authority of the Safe Drinking Water Act (SDWA) to facilitate injection of CO_2 for GS, while protecting human health and the environment by ensuring the protection of underground sources of drinking water (USDWs). The Class VI regulations are built upon 35 years of federal experience regulating underground injection wells, and many additional years of state UIC program expertise. The EPA and states have decades of UIC experience with the Class II program, which provides a regulatory framework for the protection of USDWs for CO_2 injected for purposes of EOR.

In addition, to complement both the Class VI and Class II rules, the EPA used CAA authority to develop air-side monitoring and reporting requirements for CO_2 capture, underground injection, and geologic sequestration through the GHGRP. Information collected under the GHGRP provides a transparent means for the EPA and the public to continue to evaluate the effectiveness of GS.

As explained below, these requirements help ensure that sequestered CO_2 will remain in place, and, using SDWA and CAA authorities, provide the monitoring mechanisms to identify and address potential leakage. We note the near consensus in the public responses to the Class VI rulemaking that saline and oil and gas reservoirs provide ready means for secure GS of CO_2.[415]

1. Requirements for UIC Class VI and Class II Wells

Under SDWA, the EPA developed the UIC Program to regulate the underground injection of fluids in a manner that ensures protection of USDWs. UIC regulations establish six different well classes that manage a range of injectates (*e.g.,* industrial and municipal wastes; fluids associated with oil and gas activities; solution mining fluids; and CO_2 for geologic sequestration) and which accommodate varying geologic, hydrogeological, and other conditions. The standards apply to injection into any type of formation that meets the rule's rigorous criteria, and so apply not only to injection into deep

[412] The NETL cost estimates for CO_2 transport assume a pipeline of 100 kilometers. NETL (2015) at p. 44.

[413] The data in Figure 1 is based on estimates compiled by the DOE's National Carbon Sequestration Database and Geographic Information System (NATCARB) and published in the United States 2012 Carbon Utilization and Storage Atlas, Fourth Edition. As discussed in the TSD, deep saline formation potential was not assessed for Alaska, Connecticut, Hawaii, Massachusetts, Nevada, Rhode Island, and Vermont. Oil and gas storage potential was not assessed for Alaska, Washington, Nevada, and Oregon. Unmineable coal seams were not assessed for Nevada, Oregon, California, Idaho, and New York. We are assuming for purposes of our analysis here that they do not have storage potential in those formations.

[414] In this discussion, we use the term RTO to indicate both ISOs and RTOs.

[415] In that rulemaking, we stated that ''most commenters encouraged the EPA not to automatically exclude any potential injection formations for GS at this stage of deployment.'' We added that commenters suggested, in particular, ''that there is sufficient technical basis and scientific evidence to allow GS in depleted oil and gas reservoirs and in saline formations, noting that there is consensus on how to inject into these formation types.'' 75 FR at 77252 (Dec. 10, 2010).

saline formations, but also can apply to injection into unmineable coal seams and other formations. See 75 FR 77256 (Dec. 10, 2010).

The EPA's UIC regulations define the term USDWs to include current and future sources of drinking water and aquifers that contain a sufficient quantity of ground water to supply a public water system, where formation fluids either are currently being used for human consumption or that contain less than 10,000 ppm total dissolved solids.[416] UIC requirements have been in place for over three decades and have been used by the EPA and states to manage hundreds of thousands of injection wells nationwide.

a. Class VI Requirements

In 2010, the EPA established a new class of well, Class VI. Class VI wells are used to inject CO_2 into the subsurface for the purpose of long-term sequestration. See 75 FR 77230 (Dec. 10, 2010). This rule accounts for the unique nature of CO_2 injection for large-scale GS. Specifically, the EPA addressed the unique characteristics of CO_2 injection for GS including the large CO_2 injection volumes anticipated at GS projects, relative buoyancy of CO_2, its mobility within subsurface geologic formations, and its corrosivity in the presence of water. The UIC Class VI rule was developed to facilitate GS and ensure protection of USDWs from the particular risks that may be posed by large scale CO_2 injection for purposes of long-term GS. The Class VI rule establishes technical requirements for the permitting, geologic site characterization, area of review (*i.e.,* the project area) and corrective action, well construction, operation, mechanical integrity testing, monitoring, well plugging, post-injection site care, site closure, and financial responsibility for the purpose of protecting USDWs.[417] Notably:

Site characterization includes assessment of the geologic, hydrogeologic, geochemical, and geomechanical properties of a proposed GS site to ensure that Class VI wells are sited in appropriate locations and CO_2 streams are injected into suitable formations with a confining zone or zones free of transmissive faults or fractures to ensure USDW protection.[418] [419] Site characterization is designed to eliminate unacceptable sites that may pose risks to USDWs. Generally, injection of CO_2 for GS should occur beneath the lowermost formation containing a USDW.[420] To increase the availability of Class VI sites in geographic areas with very deep USDWs, waivers from the injection depth requirements may be sought where owners or operators can demonstrate USDW protection.[421]

Owners or operators of Class VI wells must delineate the project area of review using computational modeling that accounts for the physical and chemical properties of the injected CO_2 and displaced fluids and is based on an iterative process of available site characterization, monitoring, and operational data.[422] Within the area of review, owners or operators must identify and evaluate all artificial penetrations to identify those that need corrective action to prevent the movement of CO_2 or other fluids into or between USDWs.[423] [424] Due to the potentially large size of the area of review for Class VI wells, corrective actions may be conducted on a phased basis during the lifetime of the project.[425] Periodic reevaluation of the area of review is required and enables owners or operators to incorporate previously collected monitoring and operational data to verify that the CO_2 plume and the associated area of elevated pressure are moving as predicted within the subsurface.[426]

Well construction must use materials that can withstand contact with CO_2 over the operational and post-injection life of the project.[427] These requirements address the unique physical characteristics of CO_2, including its buoyancy relative to other fluids in the subsurface and its potential corrosivity in the presence of water.

Requirements for operation of Class VI injection wells account for the unique conditions that will occur during large-scale GS including buoyancy, corrosivity, and high sustained pressures over long periods of operation.[428] [429]

Owners or operators of Class VI wells must develop and implement a comprehensive testing and monitoring plan for their projects that includes injectate analysis, mechanical integrity testing, corrosion monitoring, ground water and geochemical monitoring, pressure fall-off testing, CO_2 plume and pressure front monitoring and tracking, and, at the discretion of the Class VI director, surface air and/or soil gas monitoring.[430] Owners and operators must periodically review the testing and monitoring plan to incorporate operational and monitoring data and the most recent area of review reevaluation.[431] Robust monitoring of the CO_2 stream, injection pressures, integrity of the injection well, ground water quality and geochemistry, and monitoring of the CO_2 plume and position of the pressure front throughout injection will ensure protection of USDWs from endangerment, preserve water quality, and allow for timely detection of any leakage of CO_2 or displaced formation fluids.

Although subsurface monitoring is the primary and effective means of determining if there are any risks to a USDW, the Class VI rule also authorizes the UIC Program Director to require surface air and/or soil gas monitoring on a site-specific basis. For example, the Class VI Director may require surface air/soil gas monitoring of the flux of CO_2 out of the subsurface, with elevation of CO_2 levels above background serving as

[416] 40 CFR 144.3.

[417] The Class VI rule rests on a robust technical and scientific foundation, reflecting scientific oversight and peer review. In developing these Class VI rules, the EPA engaged with the SAB, providing detailed information on key issues relating to geologic sequestration—including monitoring schemes; methods to predict and verify capacity, injectivity, and effectiveness of subsurface CO_2 storage; and characterization and management of risks associated with plume migration and pressure increases in the subsurface. See: *http://yosemite.epa.gov/sab/sabproduct.nsf/0/AD09B42B75D9E36D85257704004882CF?OpenDocument.* In addition, the EPA developed a peer reviewed Vulnerability Evaluation Framework, which served as a technical support document for both the Class VI and Subpart RR rules. See: *http://www.epa.gov/climatechange/Downloads/ghgemissions/VEF-Technical_Document_072408.pdf.* In the section 111(b) rulemaking here, the SAB Work Group, in a letter endorsed by the full SAB Committee, found that ''while the scientific and technical basis for carbon storage provisions is new and emerging science, the agency is using the best available science and has conducted peer review at a level required by agency guidance.'' Memorandum of Jan. 7, 2014, from SAB Work Group Chair to Members of the Chartered SAB and SAB Liaisons, p. 3. The letter was subsequently endorsed by the full SAB. Work Group Letter of Jan. 24, 2014, as edited by the full Committee.

[418] 75 FR 77240 and 75 FR 77247 (December 10, 2010).

[419] 40 CFR 146.82 and 146.83. Comments indicating that EPA rules have not considered issues of exposure pathways such as abandoned wells or formation fissures are mistaken. (See, *e.g.,* Comments of UARG, p. 52 (Docket entry: EPA–HQ–OAR–2013–0495–9666).)

[420] 40 CFR 146.81(d).

[421] 40 CFR 146.95.

[422] 40 CFR 146.84(a).

[423] 40 CFR 146.84(c)(1)(3) and 146.90(d)(1).

[424] 40 CFR 146.81(d) and 146.84.

[425] 40 CFR 146.84(b)(2)(iv).

[426] 40 CFR 146.84(e)(1).

[427] 40 CFR 146.86(b).

[428] 75 FR 77250–52 (December 10, 2010); see also id. at 77234–35. Commenters were mistaken in asserting (without reference to Class VI provisions) that the EPA had ignored issues relating to CO_2 properties when injected in large volumes in supercritical state into geologic formations.

[429] 40 CFR 146.88.

[430] 40 CFR 146.90.

[431] 40 CFR 146.90(j).

an indicator of potential leakage and USDW endangerment.[432]

Class VI well owners or operators must develop and update a site-specific, comprehensive emergency and remedial response plan that describes actions to be taken (*e.g.,* cease injection) to address potential events that may cause endangerment to a USDW during the construction, operation, and post-injection site care periods of the project.[433]

Financial responsibility demonstrations are required to ensure that funds will be available for all area of review corrective action, injection well plugging, post-injection site care, site closure, and emergency and remedial response.[434]

Following cessation of injection, the operator must conduct comprehensive post-injection site care activities to show the position of the CO_2 plume and the associated area of elevated pressure to demonstrate that neither poses an endangerment to USDWs.[435] The injection well also must be plugged, and following a demonstration of non-endangerment of USDWs by the Class VI owner or operator, the site must be closed.[436 437] The default duration for the post-injection site care period is 50 years, with flexibility for demonstrating that an alternative period is appropriate if it ensures non-endangerment of USDWs.[438] Following successful closure, the facility property deed must record that the underlying land is used for GS.[439]

The EPA has completed technical guidance documents on Class VI well site characterization, area of review and corrective action, well testing and monitoring, project plan development, well construction, and financial responsibility.[440 441 442 443 444 445] The EPA has also issued guidance documents on transitioning Class II wells to Class VI wells; well plugging, post-injection site care, and site closure; and recordkeeping, reporting, and data management.[446 447 448 449]

To inform the development of the UIC Class VI rule, the EPA solicited stakeholder input and reviewed ongoing domestic and international GS research, demonstration, and deployment projects. The EPA also leveraged injection experience of the UIC Program, such as injection via Class II wells for EOR. A description of the work conducted by the EPA in support of the UIC Class VI rule can be found in the preamble for the final rule (see 75 FR 77230 and 77237–240(December 10, 2010)).

The EPA has issued Class VI permits for six wells under two projects. In September 2014, a UIC Class VI injection well permit (to construct) was issued by the EPA to Archer Daniels Midland for an ethanol facility in Decatur, Illinois. The goal of the project is to demonstrate the ability of the Mount Simon geologic formation, a deep saline formation, to accept and retain industrial scale volumes of CO_2 for permanent GS. The permitted well has a projected operational period of five years, during which time 5.5 million metric tons of CO_2 will be injected into an area of review with a radius of approximately 2 miles.[450] Following the operational period, Archer Daniels Midland plans a post-injection site care period of ten years.[451] In September 2014, the EPA also issued four Class VI injection well permits (to construct) to the FutureGen Industrial Alliance project in Jacksonville, Illinois, which proposed to capture CO_2 emissions from a coal-fired power plant in Meredosia, Illinois and transport the CO_2 by pipeline approximately 30 miles to the deep saline GS site.[452] The Alliance proposed to inject a total of 22 million metric tons of CO_2 into an area of review with a radius of approximately 24 miles over the 20-year life of the project, with a post-injection site care period of fifty years.[453]

Both permit applicants addressed siting and operational aspects of GS (including issues relating to volumes of the CO_2 and nature of the CO_2 injectate), and included monitoring that helps provide assurance that CO_2 will not migrate to shallower formations. The permits were based on findings that regional and local features at the site allow the site to receive injected CO_2 in specified amounts without buildup of pressure which would create faults or fractures, and further, that monitoring provides early warning of any changes to groundwater or CO_2 leakage.[454]

The permitting of these projects illustrates that permit applicants were able to address perceived challenges to issuance of Class VI permits. These permits demonstrate that these projects are capable of safely and securely sequestering large volumes of CO_2—including from steam generating units—for long-term storage since the EPA would not otherwise have issued the permits.

b. Class II Requirements

As explained in Section M.3 above, CO_2 has been injected into the subsurface via injection wells for EOR, boosting production efficiency by re-pressurizing oil and gas reservoirs and increasing the mobility of oil. There are decades of industry experience in operating EOR projects. The CO_2 injection wells used for EOR are regulated through the UIC Class II program.[455] CO_2 storage associated with Class II wells is a common occurrence and CO_2 can be safely stored where injected through Class II-permitted wells for the purpose of enhanced oil or gas-related recovery.

UIC Class II regulations issued under section 1421 of SDWA provide minimum federal requirements for site characterization, area of review, well construction (*e.g.,* casing and cementing), well operation (*e.g.,* injection pressure), injectate sampling, mechanical integrity testing, plugging and abandonment, financial responsibility, and reporting. Class II wells must undergo periodic mechanical integrity testing which will detect well construction and operational

[432] 40 CFR 146.90(h)(1) and 75 FR at 77259 (Dec. 10, 2010).

[433] 40 CFR 146.94.

[434] 40 CFR 146.85.

[435] 40 CFR 146.93.

[436] 40 CFR 146.92.

[437] 40 CFR 146.93.

[438] 40 CFR 146.93(b).

[439] 40 CFR 146.93(c).

[440] *http://water.epa.gov/type/groundwater/uic/class6/upload/epa816r13004.pdf.*

[441] *http://water.epa.gov/type/groundwater/uic/class6/upload/epa816r13005.pdf.*

[442] *http://water.epa.gov/type/groundwater/uic/class6/upload/epa816r13001.pdf.*

[443] *http://water.epa.gov/type/groundwater/uic/class6/upload/epa816r11017.pdf.*

[444] *http://water.epa.gov/type/groundwater/uic/class6/upload/epa816r11020.pdf.*

[445] *http://water.epa.gov/type/groundwater/uic/class6/upload/uicfinancialresponsibilityguidancefinal072011v.pdf.*

[446] *http://water.epa.gov/type/groundwater/uic/class6/upload/epa816p13004.pdf.* See also 40 CFR 144.19 and ''Key Principles in EPA's Underground Injection Control Program Class VI Rule Related to Transition of Class II Enhanced Oil Recovery or Gas Recovery Wells to Class VI'', April 23, 2015, Available at: *http://water.epa.gov/type/groundwater/uic/class6/upload/class2eorclass6memo.pdf.*

[447] *http://water.epa.gov/type/groundwater/uic/class6/upload/epa816p13005.pdf.*

[448] *http://water.epa.gov/type/groundwater/uic/class6/upload/epa816p13001.pdf.*

[449] *http://water.epa.gov/type/groundwater/uic/class6/upload/epa816p13002.pdf.*

[450] *http://www.epa.gov/region5/water/uic/adm/.* In addition, Archer Daniels Midland received a UIC Class VI injection well permit for a second well in December 2014. Archer Daniels Midland had been injecting CO_2 at this well since 2011 under a UIC Class I permit issued by the Illinois EPA.

[451] *http://www.epa.gov/region5/water/uic/adm/.*

[452] After permit issuance, and for reasons unrelated to the permitting proceeding, DOE initiated a structured closeout of federal support for the FutureGen project in February 2015. However, these are still active Class VI permits.

[453] *http://www.epa.gov/r5water/uic/futuregen/.*

[454] *http://www.epa.gov/r5water/uic/futuregen/; http://www.epa.gov/region5/water/uic/adm/.*

[455] 40 CFR 144.6(b).

conditions that could lead to loss of injectate and migration into USDWs.

Section 1425 of SDWA allows states to demonstrate that their program is effective in preventing endangerment of USDWs. These programs must include permitting, inspection, monitoring, record-keeping, and reporting components.

2. Relevant Requirements of the GHGRP

The GHGRP requires reporting of facility-level GHG data and other relevant information from large sources and suppliers in the United States. The final rules under 40 CFR part 60 specifically require that if an affected EGU captures CO_2 to meet the applicable emissions limit, the EGU must report in accordance with 40 CFR part 98, subpart PP (Suppliers of Carbon Dioxide) and the captured CO_2 must be injected at a facility or facilities that reports in accordance with 40 CFR part 98, subpart RR (Geologic Sequestration of Carbon Dioxide). See § 60.5555(f). Taken together, these requirements ensure that the amount of captured and sequestered CO_2 will be tracked as appropriate at project- and national-levels, and that the status of the CO_2 in its sequestration site will be monitored, including air-side monitoring and reporting.

Specifically, subpart PP provides requirements to account for CO_2 supplied to the economy. This subpart requires affected facilities with production process units that capture a CO_2 stream for purposes of supplying CO_2 for commercial applications or that capture and maintain custody of a CO_2 stream in order to sequester or otherwise inject it underground to report the mass of CO_2 captured and supplied to the economy.[456] CO_2 suppliers are required to report the annual quantity of CO_2 transferred offsite and its end use, including GS.[457]

This rule finalizes amendments to subpart PP reporting requirements, specifically requiring that the following pieces of information be reported: (1) the electronic GHG Reporting Tool identification (e–GGRT ID) of the EGU facility from which CO_2 was captured, and (2) the e–GGRT ID(s) for, and mass of CO_2 transferred to, each GS site reporting under subpart RR.[458]

As noted, this final rule also requires that any affected EGU unit that captures CO_2 to meet the applicable emissions limit must transfer the captured CO_2 to a facility that reports under GHGRP subpart RR. In order to provide clarity on this requirement, the EPA reworded the proposed language under § 60.5555(f) to use the phrase ''If your affected unit captures CO_2'' in place of the phrase ''If your affected unit employs geologic sequestration''. This revision is not a change from the EPA's initial intent.

Reporting under subpart RR is required for all facilities that have received a Class VI UIC permit for injection of CO_2.[459] Subpart RR requires facilities meeting the source category definition (40 CFR 98.440) for any well or group of wells to report basic information on the mass of CO_2 received for injection; develop and implement an EPA-approved monitoring, reporting, and verification (MRV) plan; report the mass of CO_2 sequestered using a mass balance approach; and report annual monitoring activities.[460] [461] [462] [463] Although deep subsurface monitoring is the primary and effective means of determining if there are any leaks to a USDW, the monitoring employed under a subpart RR MRV Plan can be utilized, if required by the UIC Program Director, to further ensure protection of USDWs.[464] The subpart RR MRV plan includes five major components:

A delineation of monitoring areas based on the CO_2 plume location. Monitoring may be phased in over time.[465]

An identification and evaluation of the potential surface leakage pathways and an assessment of the likelihood, magnitude, and timing, of surface leakage of CO_2 through these pathways. The monitoring program will be designed to address the risks identified.[466]

A strategy for detecting and quantifying any surface leakage of CO_2 in the event leakage occurs. Multiple monitoring methods and accounting techniques can be used to address changes in plume size and risks over time.[467]

An approach for establishing the expected baselines for monitoring CO_2 surface leakage. Baseline data represent pre-injection site conditions and are used to identify potential anomalies in monitoring data.[468]

A summary of considerations made to calculate site-specific variables for the mass balance equation. Site-specific variables may include calculating CO_2 emissions from equipment leaks and vented emissions of CO_2 from surface equipment, and considerations for calculating CO_2 from produced fluids.[469]

Subpart RR provides a nationally consistent mass balance framework for reporting the mass of CO_2 that is sequestered. Certain monitoring and operational data for a GS site is required to be reported to the EPA annually. More information on the MRV plan and annual reporting is available in the subpart RR final rule (75 FR 75065; December 1, 2010) and its associated technical support document.[470]

Under this final rule, any well receiving CO_2 captured from an affected EGU, be it a Class VI or Class II well, must report under subpart RR.[471] As explained below in Section V.N.5.a, a Class II well's UIC regulatory status does not change because it receives such CO_2. Nor does it change by virtue of reporting under subpart RR.

3. UIC and GHGRP Rules Provide Assurance To Prevent, Monitor, and Address Releases of Sequestered CO_2 to Air

Together the requirements of the UIC and GHGRP programs help ensure that sequestered CO_2 will remain secure, and provide the monitoring mechanisms to identify and address potential leakage using SDWA and CAA authorities. The EPA designed the GHGRP subpart RR requirements for GS with consideration of UIC requirements. The monitoring required by GHGRP subpart RR is complementary to and builds on UIC monitoring and testing requirements. 75 FR 77263. Although the regulations for Class VI and Class II injection wells are designed to ensure protection of USDWs from endangerment the practical effect of these complementary technical requirements, as explained below, is that they also prevent releases of CO_2 to the atmosphere.

The UIC and GHGRP programs are built upon an understanding of the mechanisms by which CO_2 is retained in geologic formations, which are well understood and proven.

Structural and stratigraphic trapping is a physical trapping mechanism that occurs when the CO_2 reaches a stratigraphic zone with low permeability (*i.e.,* geologic confining

[456] 40 CFR 98.420(a)(1).

[457] 40 CFR 98.426.

[458] 40 CFR 98.426(h).

[459] 40 CFR 98.440.

[460] 40 CFR 98.446.

[461] 40 CFR 98.448.

[462] 40 CFR 98.446(f)(9) and (10).

[463] 40 CFR 98.446(f)(12).

[464] See 75 FR at 77263 (Dec. 10, 2010).

[465] 40 CFR 98.448(a)(1).

[466] 40 CFR 98.448(a)(2).

[467] 40 CFR 98.448(a)(3).

[468] 40 CFR 98.448(a)(4).

[469] 40 CFR 98.448(a)(5).

[470] Technical Support Document: ''General Technical Support Document for Injection and Geologic Sequestration of Carbon Dioxide: Subparts RR and UU'' (Docket EPA–HQ–OAR–2009–0926), November 2010.

[471] See § 60.5555(f).

system) that prevents further upward migration.

Residual trapping is a physical trapping mechanism that occurs as residual CO_2 is immobilized in formation pore spaces as disconnected droplets or bubbles at the trailing edge of the plume due to capillary forces.

Adsorption trapping is another physical trapping mechanism that occurs when CO_2 molecules attach to the surfaces of coal and certain organic rich shales, displacing other molecules such as methane.

Solubility trapping is a geochemical trapping mechanism where a portion of the CO_2 from the pure fluid phase dissolves into native ground water and hydrocarbons.

Mineral trapping is a geochemical trapping mechanism that occurs when chemical reactions between the dissolved CO_2 and minerals in the formation lead to the precipitation of solid carbonate minerals.

a. Class VI Wells

As just discussed in Section V.N.1, the UIC Class VI rule provides a framework to ensure the safety of underground injection of CO_2 such that USDWs are not endangered. As explained below, protection against releases to USDWs likewise assures against releases to ambient air. Through the injection well permit application process, the Class VI permit applicant (*i.e.,* a prospective Class VI well owner or operator) must demonstrate that the injected CO_2 will be trapped and retained in the geologic formation, and not migrate out of the injection zone or the approved project area (*i.e.,* the area of review). To assure that CO_2 is confined within the injection zone, major components to be considered and included in Class VI permits are site characterization, area of review delineation and corrective action, well construction and operation, testing and monitoring, financial responsibility, post-injection site care, well plugging, emergency and remedial response, and site closure as described in Section V.N.1.

Site characterization provides the foundation for successful GS projects. It includes evaluation of the chemical and physical mechanisms that will occur in the subsurface to immobilize and securely store the CO_2 within the injection zone over the long-term (see above). Site characterization requires a detailed assessment of the geologic, hydrogeologic, geochemical, and geomechanical properties of the proposed GS site to ensure that wells are sited in suitable locations.[472] Data and information collected during site characterization are used in the development of injection well construction and operating plans; provide inputs for modeling the extent of the injected CO_2 plume and related pressure front; and establish baseline information to which geochemical, geophysical, and hydrogeologic site monitoring data collected over the life of the injection project can be compared.

The Class VI rules contain rigorous subsurface monitoring requirements to assure that the chosen site is functioning as characterized. This subsurface monitoring should detect leakage of CO_2 before CO_2 would reach the atmosphere. For example, when USDWs are present, they are generally located above the injection zone. If CO_2 were to reach a USDW prior to being released to the atmosphere, the presence of CO_2 or geochemical changes that would be caused by CO_2 migration into unauthorized zones would be detected by a UIC Class VI monitoring program that is approved and periodically evaluated/adjusted based on permit conditions.

Likewise, UIC Class VI mechanical integrity testing requirements are designed to confirm that a well maintains internal and external mechanical integrity. Continuous monitoring of the internal mechanical integrity of Class VI wells ensures that injection wells maintain integrity and serves as a way to detect problems with the well system. Mechanical integrity testing provides an early indication of potential issues that could lead to CO_2 leakage from the confining zone, providing assurance and verification that CO_2 will not reach the atmosphere.

Further assurance is provided by the regulatory requirement that injection must cease if there is evidence that the injected CO_2 and/or associated pressure front may cause endangerment to a USDW.[473] Once the anomalous operating conditions are verified, the cessation of injection, as required by UIC permits, will minimize any risk of release to air.

Following cessation of injection, the operator must conduct comprehensive post-injection site care to show the position of the CO_2 plume and the associated area of elevated pressure to demonstrate that neither poses an endangerment to USDWs—also having the practical effect of preventing releases of CO_2 to the atmosphere. Post-injection site care includes appropriate monitoring and other needed actions (including corrective action). The default duration for the post-injection site care period is 50 years, with flexibility for demonstrating that an alternative period is appropriate if it ensures non-endangerment of USDWs.

As the EPA has found, the UIC Class VI injection well requirements protect against releases from all exposure pathways. Specifically, the EPA stated that the Class VI rules ''[are] specifically designed to ensure that the CO_2 (and any incidental associated substances derived from the source materials and the capture process) will be isolated within the injection zone.'' The EPA further stated that ''[t]he EPA concluded that the elimination of exposure routes through these requirements, which are implemented through a SDWA UIC permit, will ensure protection of human health and the environment. . .''.[474]

GHGRP subpart RR complements these UIC Class VI requirements. Requirements under the UIC program are focused on demonstrating that USDWs are not endangered as a result of CO_2 injection into the subsurface, while requirements under the GHGRP through subpart RR enable accounting for CO_2 that is geologically sequestered. A methodology to account for potential leakage is developed as part of the subpart RR MRV plan (see Section V.N.2). The MRV plan submitted for subpart RR may describe (or provide by reference to the UIC permit) the relevant elements of the UIC permit (*e.g.* assessment of leakage pathways in the monitoring area) and how those elements satisfy the subpart RR requirements. The MRV plan required under subpart RR may rely upon the knowledge of the subsurface location of CO_2 and site characteristics that are developed in the permit application process, and operational monitoring results for UIC Class VI permitted wells.

In summary, there are well-recognized physical mechanisms for storing CO_2 securely. The comprehensive and rigorous site characterization requirements of the Class VI rules assure that sites with these properties are selected. Subsurface monitoring serves to assure that the sequestration site operates as intended, and this monitoring continues through a post-closure period. Although release of CO_2 to air is unlikely and should be detected prior to release by subsurface monitoring, the subpart RR air-side monitoring and reporting regime

[472] 40 CFR 146.82(a) and (c).

[473] 40 CFR 146.94(b).

[474] 79 FR at 353 (January 3, 2014) (Final Hazardous Waste Management System: Conditional Exclusion for Carbon Dioxide (CO_2) Streams in Geologic Sequestration Activities under subtitle C of RCRA). See Section N.5.c below.

provides back up assurance that sequestered CO_2 has not been released to the atmosphere.

b. Class II Wells

The Class II rules likewise are designed to protect USDWs during EOR operation, including the injection of CO_2 for EOR. For example, UIC Class II minimum federal requirements promulgated under SDWA address site characterization, area of review, well construction (*e.g.,* casing and cementing), well operation (*e.g.,* injection pressure), injectate sampling, mechanical integrity testing, plugging and abandonment, financial responsibility, and reporting. Class II wells must undergo periodic mechanical integrity testing which will detect well construction and operational conditions that could lead to loss of injectate and migration into USDWs. The establishment of maximum injection pressures, designed to ensure that the pressure in the injection zone during injection does not initiate new fractures or propagate existing fractures in the confining zone, prevents injection from causing the movement of fluids into an underground source of drinking water. The safeguards that protect USDWs also serve as an early warning mechanism for releases of CO_2 to the atmosphere.

CO_2 injected via Class II wells becomes sequestered by the trapping mechanisms described above in this Section V.N.3. As with Class VI wells, for Class II wells that report under subpart RR, there is monitoring to evaluate whether CO_2 used for EOR will remain safely in place both during and after the injection period. Subpart RR provides a CO_2 accounting framework that will enable the EPA to assess both the project-level and national efficacy of geologic sequestration to determine whether additional requirements are necessary and, if so, inform the design of such regulations.

c. Response to Comments

Commenters maintained that GS was not demonstrated for CO_2 captured from EGUs. In addition, commenters noted that the volumes of captured CO_2 would be considerably larger than from existing GS sites, and could quadruple amounts injected into Class II EOR wells. In addition to volumes of CO_2 to be injected, commenters opined on the possibility of sporadic CO_2 supply due to the nature of EGU operation.[475]

The EPA does not agree. CO_2 capture from EGUs is demonstrated as discussed in Sections V.D and V.E. As discussed below, the volumes of CO_2 are comparable to the amounts that have been injected at large scale commercial operations. The EPA also disagrees that the volume of CO_2 would quadruple amounts injected into Class II EOR wells because CO_2 may be sequestered in deep saline formations, which have widespread geographic availability (see Section M.1). The BSER determination and regulatory impact analysis for this rule relies on GS in deep saline formations.[476] However, the EPA also recognizes the potential for sequestering CO_2 via EOR and allows the use of EOR as a compliance option. According to data reported to the GHGRP, approximately 60 million metric tons of CO_2 were supplied to EOR in the United States in 2013.[477] Approximately 70 percent of total CO_2 supplied in the United States was produced from geologic (natural) CO_2 sources and approximately 30 percent was captured from anthropogenic sources. CO_2 pipeline systems, such as those serving the Permian Basin, have multiple sources of CO_2 that serve to levelize the pipeline supply, thus minimizing the effect of supply on the EOR operator.

GS of anthropogenic CO_2 in deep saline formations is demonstrated. First, as explained above, the EPA has issued construction permits under the Class VI program. It would not have done so, and under the regulations cannot have done so, without demonstrations that CO_2 would be securely confined. One of these projects was for a steam generating EGU.

Second, international experience with large scale commercial GS projects has demonstrated through extensive monitoring programs that large volumes of CO_2 can be safely injected and securely sequestered for long periods of time at volumes and rates consistent with those expected under this rule. This experience has also demonstrated the value and efficacy of monitoring programs to determine the location of CO_2 in the subsurface and detect potential leakage through the presence of CO_2 in the shallow subsurface, near surface and air.

The Sleipner CO_2 Storage Project is located at an offshore gas field in the North Sea where CO_2 must be removed from the natural gas in order to meet customer requirements and reduce costs. The project began injecting CO_2 into the deep subsurface in 1996. The single offshore injection well injects approximately 1 million metric tons per year into a thick, permeable sandstone above the gas producing zone. Approximately 15 million metric tons of CO_2 have been injected since inception. Many US and international organizations have conducted monitoring at Sleipner. The location and dimensions of the CO_2 plume have been measured numerous times using 3-dimensional seismic monitoring since the 1994 pre-injection survey. The monitoring data have demonstrated that although the plume is behaving differently than initially modeled due to thin layers of impermeable shale that were not initially identified in the reservoir model, the CO_2 remains trapped in the injection zone. Numerous other techniques have been successfully used to monitor CO_2 storage at Sleipner. The research and monitoring at Sleipner demonstrates the value of a comprehensive approach to site characterization, computational modeling and monitoring, as is required under UIC Class VI rules. The experience at Sleipner demonstrates that large volumes of CO_2, of the same order of magnitude expected for an EGU, can be safely injected and stored in saline reservoirs over an extended period.

Snøhvit is another large offshore CO_2 storage project, located at a gas field in the Barents Sea. Like Sleipner the natural gas must be treated to reduce high levels of CO_2 to meet processing standards and reduce costs. Gas is transported via pipeline 95 miles to a gas processing and liquefied natural gas plant and the CO_2 is piped back offshore for injection. Approximately 0.7 million metric tons per year CO_2 are injected into permeable sandstone below the gas reservoir. Between 2008 and 2011, the operator observed pressure increases in the injection formation (Tubaen Formation) greater than expected and conducted time lapse seismic surveys and studies of the injection zone and concluded that the pressure increase was mainly caused by a limited storage capacity in the formation.[478] In 2011,

[475] See, *e.g.* Comments of Southern Company, p. 41 (Docket entry: EPA–HQ–OAR–2013–0495–10095).

[476] The EPA anticipates EOR projects may be early GS projects because these formations have been previously well characterized for hydrocarbon recovery, likely already have suitable infrastructure (*e.g.,* wells, pipelines, etc.), and have an associated economic benefit of oil production.

[477] Greenhouse Gas Reporting Program, data reported as of August 18, 2014.

[478] Grude, S. M. Landrøa, and J. Dvorkinb, 2014, Pressure effects caused by CO_2 injection in the Tubåen Fm., the Snøhvit field. International Journal of Greenhouse Gas Control 27 (2014) 178–187. Commenters argued that the project had failed to sequester CO_2, referring to the initial cessation of injection. See, *e.g.* Comments of UARG p. 56 (Docket entry: EPA–HQ–OAR–2013–0495–9666). In fact, injection resumed successfully, as described in the text above.

the injection well was modified and injection was initiated in a second interval (Stø Formation) in the field to increase the storage capacity. Approximately 3 million metric tons of CO_2 have been injected since 2008. Monitoring demonstrates that no leakage has occurred, again demonstrating that large volumes of CO_2, of the same order of magnitude expected for an EGU, can be safely injected and stored in deep saline formations over an extended period.

As discussed above in Sections V.E.2.a and M, CO_2 from the Great Plains Synfuels plant in North Dakota has been injected into the Weyburn oil field in Saskatchewan Canada since 2000. Over that time period the project has injected more than 16 million metric tons of CO_2. It is anticipated that approximately 40 million metric tons of CO_2 will be permanently sequestered over the lifespan of the project. Extensive monitoring by U.S. and international partners has demonstrated that no leakage has occurred. The sources of CO_2 for EOR may vary (*e.g.,* industrial processes, power generation); however, this does not impact the effectiveness of EOR operations (see Section V.M.3).

CO_2 used for EOR may come from anthropogenic or natural sources. The source of the CO_2 does not impact the effectiveness of the EOR operation. CO_2 capture, treatment and processing steps provide a concentrated stream of CO_2 in order to meet the needs of the intended end use. CO_2 pipeline specifications of the U.S. Department of Transportation Pipeline Hazardous Materials Safety Administration found at 49 CFR part 195 (Transportation of Hazardous Liquids by Pipeline) apply regardless of the source of the CO_2 and take into account CO_2 composition, impurities, and phase behavior. Additionally, EOR operators and transport companies have specifications to ensure related to the composition of CO_2. These requirements and specifications ensure EOR operators receive a known and consistent CO_2 stream.

At the In Salah CO_2 storage project in Algeria, CO_2 is removed from natural gas produced at three nearby gas fields in order to meet export quality specification. The CO_2 is transported by pipeline approximately 3 miles to the injection site. Three horizontal wells are used to inject the CO_2 into the down-dip aquifer leg of the gas reservoir approximately 6,200 feet deep. Between 2004 and 2011 over 3.8 million metric tons of CO_2 were stored. Injection rates in 2010 and 2011 were approximately 1 million metric tons per year. Storage integrity has been monitored by several U.S. and international organizations and the monitoring program has employed a wide range of geophysical and geochemical methods, including time lapse seismic, microseismic, wellhead sampling, tracers, down-hole logging, core analysis, surface gas monitoring, groundwater aquifer monitoring and satellite data. The data have been used to support periodic risk assessments during the operational phase of the project. In 2010 new data from seismic, satellite and geomechanical models were used to inform the risk assessment and led to the decision to reduce CO_2 injection pressures due to risk of vertical leakage into the lower caprock, and risk of loss of well integrity. The caprock at the site consisted of main caprock units, providing the primary seal, and lower caprock units, providing additional buffers. There was no leakage from the well or through the caprock, but the risk analysis identified an increased risk of leakage, therefore, the aforementioned precautions were taken. Additional analysis of the reservoir, seismic and geomechanical data led to the decision to suspend CO_2 injection in June 2011. No leakage has occurred and the injected CO_2 remains safely stored in the subsurface. The decision to proceed with safe shutdown of injection resulted from the analysis of seismic and geomechanical data to identify and respond to storage site risk. The In Salah project demonstrates the value of developing an integrated and comprehensive set of baseline site data prior to the start of injection, and the importance of regular review of monitoring data. Commenters also noted that the data collection and analysis had proven effective at preventing any release of sequestered CO_2 to either underground drinking water sources or to the atmosphere.[479]

These projects demonstrate that sequestration of CO_2 captured from industrial operations has been successfully conducted on a large scale and over relatively long periods of time. The volumes of captured CO_2 are within the same order of magnitude as that expected from EGUs. Even though potentially adverse conditions were identified at some projects (In Salah and Snøhvit), there were no releases to air and the monitoring systems were effective in identifying the issues in a timely manner, and these issues were addressed effectively. In each case, the site-specific characteristics were evaluated on a case-by-case basis to select a site where the geologic conditions are suitable to ensure long-term, safe storage of CO_2. Each project was designed to address the site-specific characteristics and operated to successfully inject CO_2 for safe storage.

4. Must the standard of performance for CO_2 include CAA requirements on the sequestration site?

One commenter maintained as a matter of law that a standard predicated on use of CCS is not a ''system of emission reduction'', and therefore is not a ''standard of performance'' within the meaning of section 111 (a)(1) of the Act. The commenter argued that the standard does not require sequestration of captured CO_2 but only capture, so that no emission reductions are associated with the standard. A gloss on this argument is that there are no enforceable requirements for the captured CO_2 (''[t]he fate of that [captured] CO_2 is something that the proposed standard does not proscribe with enforceable requirements''). The commenter further argues that a ''system of emission reduction'' under section 111 must be ''designed into the new source *itself''* so that off-site underground sequestration of captured CO_2 emissions ''could never satisfy the statutory requirements governing a 'standard of performance''' (emphasis original).[480]

The EPA disagrees with both the legal and factual assertions in this comment. As to the legal point, the commenter fails to distinguish capture and sequestration of carbon from every other section 111 standard which is predicated on capture of a pollutant. Indeed, all emission standards not predicated on outright pollutant destruction involve capture of the pollutant and its subsequent disposition in the capturing medium. Thus, metals are captured in devices like baghouses or scrubbers, leaving a solid waste or wastewater to be managed. Gases can be captured with activated carbon or under pressure, again requiring further management of the captured pollutant(s). The EPA is required to consider these potential implications in promulgating an NSPS. See section 111(a)(1) (in promulgating a standard of performance under section 111, the EPA must ''tak[e] into account . . . any nonair quality health and environmental

[479] ''It is important to note that although the In Salah project is no longer injecting CO_2, the CCS community still views this early saline project as a success because the monitoring program served its intended purpose. That is, the monitoring methods deployed at this site informed the operator of a potential problem, leading to a shutdown of CO_2 injection before the Caprock was breached.'' Comment of EPRI, p. 14 Docket entry: EPA–HQ–OAR–2013–0495–8925).

[480] Comments of UARG, pp. 37–38 (Docket entry: EPA–HQ–OAR–2013–0495–9666).

impact''). The EPA thus considers such issues as solid waste and wastewater generation as part of determining if a system of emission reduction is ''best'' and ''adequately demonstrated'' under section 111. See Section V.O below (discussion of this rule's potential cross-media impacts).

The further comment that the standard is arbitrary because it fails to impose any requirements on the captured CO_2 is misplaced. The commenter mischaracterizes the standard as requiring capture only. The BSER is not just capturing a certain amount of CO_2, but sequestering it. Sequestration can occur either on-site or off-site. Sequestration sites receiving and injecting the captured CO_2 are required to obtain UIC permits and report under subpart RR of the GHGRP. They must conduct comprehensive monitoring as part of these obligations. Although the NSPS does not impose regulatory requirements on the transportation pipeline or the sequestration site, such requirements already exist under other regulatory programs of the Department of Transportation and the EPA. In particular, the EPA is reasonably relying on the already-adopted, and very rigorous, Class VI well requirements in combination with the subpart RR requirements to provide secure sequestration of captured CO_2. The EPA has also considered carefully the requirements and operating history of the Class II requirements for EOR wells, which, in combination with the subpart RR requirements, ensure protection of USDWs from endangerment, provide the monitoring mechanisms to identify and address potential leakage using SDWA and CAA authorities, and have the practical effect of preventing releases of CO_2 to the atmosphere. This is analogous to the many section 111 standards of performance for metals which result in a captured air pollution control residue to be disposed of pursuant to waste management requirements of the rules implementing the Resource Conservation and Recovery Act. It is also analogous to the many section 111 standards of performance for metals or organics captured in wet air pollution control systems resulting in wastewater discharged to a navigable water where pollutant loadings are controlled under rules implementing the Clean Water Act. Again, these are non-air environmental impacts for which the EPA must account in establishing a section 111(a) standard. The EPA has reasonably done so here based on the regulatory regimes of the Class VI and Class II UIC requirements in combination with the monitoring regime of the subpart RR reporting rules, as well as the CO_2 pipeline standards of the Department of Transportation.

In this regard, the EPA notes that at proposal it acknowledged the possibility ''that there can be downstream losses of CO_2 after capture, for example during transportation, injection or storage.'' 79 FR at 1484. Given the rigorous substantive requirements and the monitoring required by the Class VI rules, the complementary monitoring regime of the subpart RR MRV plan and reporting rules, as well as the regulatory requirements for Class II wells, any such losses would be de minimis. Indeed, the same commenter maintained that the monitoring requirements of the Class VI rule are overly stringent and that a 50-year post-injection site care period is unnecessarily long.[481] As it happens, as noted above, the Class VI rules allow for an alternative post-injection site care period based on a site-specific demonstration. See 40 CFR 146.93(b).

The EPA addresses this comment in more detail in Chapter 2 of the Response-to-Comment Document.

5. Other Perceived Obstacles to Geologic Sequestration

a. Class II to Class VI transition

A number of commenters maintained that the Class VI rules could effectively force all Class II wells to transition to Class VI wells if they inject anthropogenic CO_2, and further maintained that, as a practical matter, this would render EOR unavailable for such CO_2. The EPA disagrees with these comments. Injection of anthropogenic CO_2 into Class II wells does not force transition of these wells to Class VI wells—not during the well's active operation and not when EOR operations cease. We recognize the widespread use of EOR and the expectation that injected CO_2 can remain underground. The EPA issued a memorandum to its regional offices on April 23, 2015 reflecting these principles: [482]

Geologic storage of CO_2 can continue to be permitted under the UIC Class II program.

Use of anthropogenic CO_2 in EOR operations does not necessitate a Class VI permit.

Class VI site closure requirements are not required for Class II CO_2 injection operations.

EOR operations that are focused on oil or gas production will be managed under the Class II program. If oil or gas recovery is no longer a significant aspect of a Class II permitted EOR operation, the key factor in determining the potential need to transition an EOR operation from Class II to Class VI is increased risk to USDWs related to significant storage of CO_2 in the reservoir, where the regulatory tools of the Class II program cannot successfully manage the risk.[483]

b. GHGRP Subpart RR

A number of commenters maintained that no EOR operator would accept captured carbon from an EGU due to the reporting and other regulatory burdens imposed by the monitoring requirements of GHGRP subpart RR.[484] They noted that preparing a subpart RR MRV plan could cost upwards of $100,000 which would be cost prohibitive given other available sources of CO_2.

The EPA disagrees with this comment in several respects. First, the BSER determination and regulatory impact analysis for this rule relies on GS in deep saline formations, not on EOR. However, the EPA also recognizes the potential for sequestering CO_2 via EOR, but disagrees that subpart RR requirements effectively preclude or substantially inhibit the use of EOR.

The cost of compliance with subpart RR is not significant enough to offset the potential revenue for the EOR operator from the sale of produced oil for CCS projects that are reliant on EOR. First, the costs associated with subpart RR are relatively modest, especially in comparison with revenues from an EOR field. In the economic impact analysis for subpart RR, the EPA estimated that an EOR project with a Class II permit would incur a first year cost of up to $147,030 to develop an MRV plan, and an annual cost of $27,787 to maintain the plan; the EPA estimated annual reporting and recordkeeping costs at $13,262 per year.[485] Monitoring costs

[481] Comments of UARG, p. 63 (Docket entry: EPA–HQ–OAR–2013–0495–9666).

[482] ''Key Principles in EPA's Underground Injection Control Program Class VI Rule Related to Transition of Class II Enhanced Oil Recovery or Gas Recovery Wells to Class VI'', April 23, 2015. Available at: *http://water.epa.gov/type/groundwater/uic/class6/upload/class2eorclass6memo.pdf*.

[483] In this regard, the Class VI rules provide that, owners or operators that are injecting carbon dioxide for the primary purpose of long-term storage into an oil and gas reservoir must apply for and obtain a Class VI geologic sequestration permit when there is an increased risk to USDWs compared to Class II operations. 40 CFR 144.19.

[484] See *e.g.,* comments of UARG, p, 63 (Docket entry: EPA–HQ–OAR–2013–0495–9666); Southern Co., p. 37 (Docket entry: EPA–HQ–OAR–2013–0495–10095); American Petroleum Institute pp. 40–50 Docket entry: EPA–HQ–OAR–2013–0495–10098).

[485] Subpart RR costs are presented in 2008 US dollars.

are estimated to range from $0.02 per metric ton (base case scenario) to approximately $2 per metric ton of CO_2 (high scenario). Using a range of scenarios (that included high end estimates), these subpart RR costs are approximately three to four percent of estimated revenues for an average EOR field, indicating that the costs can readily be absorbed. 75 FR 75073.

Furthermore, there is a demand for new CO_2 by EOR operators, even beyond current natural sources of CO_2. For example, in an April 2014 study, DOE concluded that future development of EOR will need to rely on captured CO_2.[486] Thus, the argument that EOR operators will obtain CO_2 from other sources without triggering subpart RR responsibilities, which assumes adequate supplies of CO_2 from other sources, lacks foundation. In addition, the Internal Revenue Code section 45Q provides a tax credit for CO_2 sequestration which is far greater than subpart RR costs.[487] In sum, the cost of complying with subpart RR requirements, including the cost of MRV, is not significant enough to deter EOR operators from purchasing EGU captured CO_2.

The EPA addresses these comments in more detail in the Response to Comment Document.

c. Conditional exclusion for geologic sequestration of CO2 streams under the Resource Conservation and Recovery Act (RCRA)

Certain commenters voiced concerns that regulatory requirements for hazardous wastes might apply to captured CO_2 and these requirements might be inconsistent with, or otherwise impede, GS of captured CO_2 from EGUs. The EPA has acted to remove any such (highly conjectural) uncertainty. The Resource Conservation and Recovery Act (RCRA) authorizes the EPA to regulate the management of hazardous wastes. In particular, RCRA Subtitle C authorizes a cradle to grave regulatory program for wastes identified as hazardous, whether specifically listed as hazardous or whether the waste fails certain tests of hazardous characteristics. The EPA currently has little information to conclude that CO_2 streams (defined in the RCRA exclusion rule as including incidental associated substances derived from the source materials and the capture process, and any substances added to the stream to enable or improve the injection process) might be identified as ''hazardous wastes'' subject to RCRA Subtitle C regulation.[488] Nevertheless, to reduce potential uncertainty regarding the regulatory status of CO_2 streams under RCRA Subtitle C, and in order to facilitate the deployment of geologic sequestration, the EPA recently concluded a rulemaking to exclude certain CO_2 streams from the RCRA definition of hazardous waste.[489] In that rulemaking, the EPA determined that if any such CO_2 streams would be hazardous wastes, further RCRA regulation is unnecessary to protect human health and the environment provided certain conditions are met. Specifically, the rule conditionally excludes from Subtitle C regulations CO_2 streams if they are (1) transported in compliance with U.S. Department of Transportation or state requirements; (2) injected in compliance with UIC Class VI requirements (summarized above); (3) no other hazardous wastes are mixed with or co-injected with the CO_2 stream; and (4) generators (*e.g.,* emission sources) and Class VI well owners or operators sign certification statements. See 40 CFR 261.4(h)).[490] The D.C. Circuit recently dismissed all challenges to this rule in *Carbon Sequestration Council and Southern Company Services* v. *EPA,* No. 787 F. 3d 1129 (D.C. Cir. 2015).

d. Other perceived uncertainties

Other commenters claimed that various legal uncertainties preclude a finding that geologic sequestration of CO_2 from EGUs can be considered to be adequately demonstrated. Many of the issues referred to in comments relate to property rights: issues of ownership of pore space, relationship of sequestration to ownership of mineral rights, issues of dealing with multiple landowners, lack of state law frameworks, or competing, inconsistent state laws.[491] Other commenters noted the lack of long-term liability insurance, and noted uncertainties regarding long-term liability generally.[492]

An IPCC special report on CCS found that with an appropriate site selection, a monitoring program, a regulatory system, and the appropriate use of remediation methods, the risks of GS would be comparable to risks of current activities, such as EOR, acid gas injection and underground natural gas storage.[493] Furthermore, an interagency CCS task force examined GS-related legal issues thoroughly and concluded that early CCS projects can proceed under the existing legal framework with respect to issues such as property rights and liability.[494] As noted earlier, both the Archer Daniels Midland (ADM) and FutureGen projects addressed siting and operational aspects of GS (including issues relating to volumes of the CO_2 and the nature of the CO_2 injectate) in their permit applications. The fact that these applicants pursued permits indicates that they regarded any potential property rights issues as resolvable.

Commenter American Electric Power (AEP) referred to its own experience with the Mountaineer demonstration project. AEP noted that although this project was not full scale, finding a suitable repository, notwithstanding a generally favorable geologic area, proved difficult. The company referred to years spent in site characterization and digging multiple wells.[495] Other commenters noted more generally that site characterization issues can be time-consuming and difficult, and quoted

[486] ''Near Term Projections of CO_2 Utilization for Enhanced Oil Recovery''. DOE/NETL–2014/1648. April 2014.

[487] *http://www.irs.gov/irb/2009-44_IRB/ar11.html.* The section 45Q tax credit for calendar year 2015 is $10.92 per metric ton of qualified CO_2 that is captured and used in a qualified EOR project and $21.85 per metric ton of qualified CO_2 that is captured and used in a qualified non-EOR GS project. *http://www.irs.gov/irb/2015-26_IRB/ar14.html.*

[488] No hazardous waste listings apply to CO_2 streams. Therefore, a CO_2 stream could be identified (*i.e.* defined) as a hazardous waste only if it exhibits one or more of the hazardous characteristics. 79 FR 355 (Jan 3. 2014).

[489] 79 FR 350 (Jan. 3, 2014).

[490] The EPA made clear in the final conditional exclusion that that rule does not address, and is not intended to affect the RCRA regulatory status of CO_2 streams that are injected into wells other than Class VI. However, the EPA noted in the preamble to the final rule that (based on the limited information provided in public comments) should CO_2 be used for its intended purpose as it is injected into UIC Class II wells for the purpose of EOR/EGR (enhanced oil recovery/enhanced gas recovery), it is the EPA's expectation that such an injection process would not generally be a waste management activity. 79 FR 355. The EPA encouraged persons to consult with the appropriate regulatory authority to address any fact-specific questions that they may have regarding the status of CO_2 in situations that are beyond the scope of that rule. *Id.* Moreover, use of anthropogenic CO_2 for EOR is long-standing and has flourished in all of the years that EPA's subtitle C regulations (which among other things, define what a solid waste is for purposes of those regulations) have been in place. The RCRA subtitle C regulatory program consequently has not been an impediment to use of anthropogenic CO_2 for EOR.

[491] See *e.g.* Comments of Duke Energy, p. 28 Docket entry: EPA–HQ–OAR–2013–0495–9426); UARG, p. 62 (Docket entry: EPA–HQ–OAR–2013–0495–9666); AEP, p. 91 (Docket entry: EPA–HQ–OAR–2013–0495–10618).

[492] See *e.g.* Comments of UARG, pp. 26 (Docket entry: EPA–HQ–OAR–2013–0495–9666), 62; EEI, p. 92 Docket entry: EPA–HQ–OAR–2013–0495–9780); Duke Energy, pp. 27, 28 Docket entry: EPA–HQ–OAR–2013–0495–9426).

[493] Intergovernmental Panel on Climate Change. (2005). Special Report on Carbon Dioxide Capture and Storage.

[494] *http://www.epa.gov/climatechange/Downloads/ccs/CCS-Task-Force-Report-2010.pdf.*

[495] AEP Comments at pp. 93, 96 (Docket entry: EPA–HQ–OAR–2013–0495–10618).

studies suggesting that it could take 5 years to obtain a Class VI permit.[496]

The EPA agrees that robust site characterization and selection is important to ensuring capacity needs are met and that the sequestered CO_2 is safely stored. Efforts to characterize geologic formations suitable for GS have been underway at DOE through the RCSPs since 2003 (see Section V.M). Additionally, since 2007, the USGS has been assessing U.S. geologic storage resources for CO_2. As noted earlier, DOE, in partnership with researchers, universities, and organizations across the country, is demonstrating that GS can be achieved safely, permanently, and economically at large scales, and projects supported by the department have safely and permanently stored 10 million metric tons of CO_2.

In the time since the commenter submitted comments several Class VI permits have been issued by the EPA. These projects demonstrate that a GS site permit applicant could potentially prepare and obtain a UIC permit concurrent with permits required for an EGU. With respect to AEP's experience with the Mountaineer demonstration project, notwithstanding difficulties, the company was able to successfully dig wells, and safely inject captured CO_2. Moreover, the company indicated it fully expected to be able to do so at full scale and explained how.[497] The EPA notes further that a monitoring program and its associated infrastructure (*e.g.,* monitoring wells) and costs will be dependent on site-specific characteristics, such as CO_2 injection rate and volume, geology, the presence of artificial penetrations, among other factors. It is thus not appropriate to generalize from AEP's experience, and assume that other sites will require the same number of wells for site characterization or injection. In this regard, we note that the ADM and FutureGen construction permits for Class VI wells involved far fewer injection wells than AEP references.[498] See also discussion of this issue in Section V.I.5 above.

O. Non-air Quality Impacts and Energy Requirements

As part of the determination that SCPC with partial CCS is the best system of emission reduction adequately demonstrated, the EPA has given careful consideration to non-air quality health and environmental impacts and energy requirements, as required by CAA section 111 (a). We have also considered those factors for alternative potential compliance paths to assure that the standard does not have unintended adverse health, environmental or energy-related consequences. The EPA finds that neither the BSER, nor the possible alternative compliance pathways, would have adverse consequences from either a non-air quality impact or energy requirement perspective.

1. Transport and Sequestration of Captured CO_2

As just discussed in detail, the EPA finds that the Class VI and II rules, as complemented by the subpart RR GHGRP reporting and monitoring requirements, amply safeguard against potential of injected CO_2 to degrade underground sources of drinking water and amply protect against any releases of sequestered CO_2 to the atmosphere. The EPA likewise finds that the plenary regulatory controls on CO_2 pipelines assure that CO_2 can be safely conveyed without environmental release, and that these rules, plus the complementary tracking and reporting rules in subpart RR, assure that captured CO_2 will be properly tracked and conveyed to a sequestration site.

2. Water Use Impacts

Commenters claimed that the EPA ignored the negative environmental impacts of the use of CCS for the mitigation of CO_2 emissions from fossil fuel-fired steam generating EGUs. In particular, commenters noted that the use of CCS will increase the water usage at units that implement CCS to meet the proposed standard of performance. At least one commenter claimed that addition of an amine-based CCS system would double the consumptive water use of a power plant, which would be unacceptable, especially in drought-ridden states and in the arid west and referenced a study in the scientific literature as support.[499] The commenter also references a DOE/NETL report that likewise notes significant increases in the amount of cooling and process water required with the use of carbon capture technology.[500] However, those studies discuss increased water use for cases where full CCS (90 percent or greater capture) is implemented. As we discussed in both the proposal and in this preamble, the EPA does not find that highly efficient new generation technology implementing full CCS is the BSER for new steam generating EGUs.

The EPA examined water use predicted from the updated DOE/NETL studies in order to determine the magnitude of increased water usage for a new SCPC implementing partial CCS to meet the final standard of 1,400 lb CO_2/MWh-g. The predicted water consumption for varying levels of partial and full CCS are provided in Table 13. The results show that a new SCPC unit that implements 16 percent partial CCS to meet the final standard would see an increase in water consumption (the difference between the predicted water withdraw and discharge) of about 6.4 percent compared to an SCPC with no CCS and the same net power output. By comparison, a unit implementing 35 percent CCS to meet the proposed emission limitation of 1,100 lb CO_2/MWh-g would see an increase in water consumption of 16.0 percent and a new unit implementing full (90 percent) CCS would see an increase of almost 50 percent.

TABLE 13—PREDICTED WATER CONSUMPTION WITH IMPLEMENTATION OF VARIOUS LEVELS OF PARTIAL CCS [501]

Technology	Raw water consumption, gpm	Increase compared to SCPC, %
SCPC	4,095	—

[496] See *e.g.* Comments of UARG, p. 55 (Docket entry: EPA–HQ–OAR–2013–0495–9666), citing to Cichanowitz CCS Report (2012).

[497] See AEP FEED Study at pp. 36–43. The company likewise explained the monitoring regime it would utilize to verify containment, and the well construction it would utilize to guarantee secure sequestration. Id. at pp. 44–54. Available at: *www.globalccsinstitute.com/publications/aep-mountaineer-ii-project-front-end-engineering-and-design-feed-report.*

[498] The FutureGen UIC Class VI injection well permits (four in total) require nine monitoring wells. *http://www.epa.gov/r5water/uic/futuregen/.* The Archer Daniels Midland UIC Class VI injection well permit issued in September 2014 (CCS2) requires five monitoring wells and the Archer Daniels Midland UIC Class VI injection well permit issued in December 2014 (CCS1) was permitted with two monitoring wells. *http://www.epa.gov/region5/water/uic/adm/.*

[499] See comments of UARG at p. 84 (Docket entry: EPA–HQ–OAR–2013–0495–9666) referencing Haibo Zhai, *et al.,* Water Use at Pulverized Coal Power Plants with Post-combustion Carbon Capture and Storage, 45 *Environ. Sci. Technol.,* 2479–85 (2011).

[500] Id at p. 84 referencing DOE/NETL–402/080108, ''Water Requirements for Existing and Emerging Thermoelectric Plant Technologies'' at 13 (Aug. 2008, Apr. 2009 revision).

TABLE 13—PREDICTED WATER CONSUMPTION WITH IMPLEMENTATION OF VARIOUS LEVELS OF PARTIAL CCS [501]—Continued

Technology	Raw water consumption, gpm	Increase compared to SCPC, %
SCPC + 16% CCS	4,359	6.4
SCPC + 35% CCS	4,751	16.0
SCPC + 90% CCS	6,069	48.2
IGCC*	3,334	−18.6
IGCC + 90% CCS*	4,815	17.6

* The IGCC results presented in the DOE/NETL report are for an IGCC with net output of 622 MWe and an IGCC with full CCS with net output of 543 MWe. The water consumption for each was normalized to 550 MWe to be consistent with the SPCP cases.

Similar to other air pollution controls—such as a wet flue gas desulfurization scrubber—utilization of post-combustion amine-based capture systems results in increased consumption of water. However, by finalizing a standard that is less stringent than the proposed limitation and by rejecting full CCS as the BSER, the EPA has reduced the increased amount of water needed as compared to a similar unit without CCS. Further, the EPA notes that there are additional opportunities to minimize the water usage at such a facility. For example, the SaskPower Boundary Dam Unit #3 post-combustion capture project captures water from the coal and from the combustion process and recycles the captured water in the process, resulting in decreased need for withdrawal of fresh water.

The EPA also examined the predicted water usage for a new IGCC and for a new IGCC implementing 90 percent CCS. The predicted water consumption for the new IGCC unit is nearly 20 percent less than that predicted for the new SCPC unit without CCS (and almost 25 percent less than the SCPC unit meeting the final standard). The EPA rejected new IGCC implementing full CCS as BSER because the predicted costs were significantly more than alternative technologies. The EPA also does not find that a new IGCC EGU is part of the final BSER (for reasons discussed in Section V.P). However, the EPA does note that IGCC is a viable alternative compliance option and, as shown here, would result in less water consumption than a compliant SCPC EGU. The EPA also notes that predicted water consumption at a new NGCC unit would be less than half that for a new SCPC EGU with the same net output.[502]

3. Energy Requirements

The EPA also examined the expected impacts on energy requirements for a new unit meeting the final promulgated standard and finds impacts to be minimal. Specifically, the EPA examined the increased auxiliary load or parasitic energy requirements of a system implementing CCS. The EPA examined the predicted auxiliary power demand from the updated DOE/NETL studies in order to determine the increased energy requirement for a new SCPC implementing partial CCS to meet the final standard of 1,400 lb CO_2/MWh-g. The predicted gross power output, the auxiliary power demand, and the parasitic power demand (percent of gross output) are provided in Table 14 for varying levels of partial and full CCS.

TABLE 14—PREDICTED PARASITIC POWER DEMAND WITH IMPLEMENTATION OF VARIOUS LEVELS OF PARTIAL CCS [503]

Generation technology	Gross power output, MWe	Auxiliary power, MWe	Parasitic demand (%)
SCPC	580	30	5.2
SCPC + 16% CCS	599	38	6.3
SCPC + 35% CCS	603	53	8.8
SCPC + 90% CCS	642	91	14.2
IGCC	748	126	16.8
IGCC + 90% CCS	734	191	26.0
CCS	734	191	26.0

The auxiliary power demand is the amount of the gross power output that is utilized within the facility rather than used to produce electricity for sale to the grid. The parasitic power demand (or parasitic load) is the percentage of the gross power output that is needed to meet the auxiliary power demand.[504] In an SCPC EGU without CCS, the auxiliary power is used to primarily to operate fans, motors, pumps, etc. associated with operation of the facility and the associated pollution control equipment. When carbon capture equipment is incorporated, additional power is needed to operate associated equipment, and steam is need to regenerate the capture solvents (*i.e.,* the solvents are heated to release the captured CO_2).

The results in Table 14 show that a new SCPC unit without CCS can expect a parasitic power demand of about 5.2 percent. A new SCPC unit meeting the

[501] Exhibits A–1 and A–2 at p. 16–17 from ''Cost and Performance Baseline for Fossil Energy Plants Supplement: Sensitivity to CO_2 Capture Rate in Coal-Fired Power Plants'', DOE/NETL–2015/1720 (June 22, 2015).

[502] The EPA also finds that the standards would not result in any significant impact on solid waste generation or management. See Section XIII.D below.

[503] Exhibits A–1 and A–2 at p. 16–17 from ''Cost and Performance Baseline for Fossil Energy Plants Supplement: Sensitivity to CO_2 Capture Rate in Coal-Fired Power Plants'', DOE/NETL–2015/1720 (June 2015).

[504] Note that this auxiliary power demand is not necessarily met from power or steam generated from the EGU. External sources can also be utilized for this purpose.

final standard of performance by implementing 16 percent partial CCS will see a parasitic power demand of about 6.3 percent, which is not a significant increase in energy requirement. Of course, new SCPC EGUs that implement higher levels of CCS will expect higher amounts of parasitic power demand. As shown in Table 14, a new SCPC EGU implementing full CCS would expect to utilize over 14 percent of its gross power output to operate the facility and the carbon capture system. But, the EPA does not find that a new SCPC implementing full CCS is the BSER for new fossil-fired steam generating units. See Section V.P.2 below.

The EPA also notes that there is on-going research sponsored by DOE/NETL and others to further reduce the energy requirements of the carbon capture systems. Progress is being made. As was mentioned previously, the heat duty (the energy required to regenerate the capture solvent) for the amine scrubbing process used at the Searles Valley facility in the mid-70's was about 12 MJ/mt CO_2 removed as compared to a heat duty of about 2.5 MJ/mt CO_2 removed for the amine processes used at Boundary Dam and for the amine system that will be used at the WA Parish facility.[505]

The EPA also examined the predicted parasitic power demand for a new IGCC and for a new IGCC implementing 90 percent CCS. As we have noted elsewhere, the auxiliary power demand for a new IGCC unit is more than that for that of a new SCPC. As one can see in Table 14, a new IGCC unit can expect to see a nearly 17 percent parasitic power demand; and a new IGCC unit implementing full CCS would expect a parasitic power demand of nearly 30 percent. Of course, the EPA rejected new IGCC implementing full CCS as BSER because of the potentially unreasonable costs. The EPA also does not find that a new IGCC EGU is part of the final BSER (for reasons discussed elsewhere in Section V.P.1 below). However, as we have noted, the EPA does find IGCC to be a viable alternative compliance option. Utilities and project developers should consider the increased auxiliary power demand for an IGCC when considering their options for new power generation. The EPA also notes that the predicted parasitic load for a new NGCC unit would be about 2 percent—less than half that for a new SCPC EGU with the same net output.[506]

With respect to potential nationwide impacts on energy requirements, as described above in Section V.H.3 and more extensively in the RIA chapter 4, the EPA reasonably projects that no new non-compliant fossil-fuel fired steam electric capacity will be constructed through 2022 (the end of the 8 year review cycle for NSPS). It is possible, as described earlier, that some new sources could be built to preserve fuel diversity, but even so, the number of such sources would be small and therefore would not significantly impact national energy requirements (assuming that such sources would not already be reflected in the baseline conditions just noted).

P. Options That Were Considered by the EPA but Were Ultimately Not Determined To Be the BSER

In light of the comments received, the EPA re-examined several alternative systems of emission reduction and reaffirms in this rulemaking our proposed determination that those alternatives do not represent the ''best'' system of emission reduction when compared against the other available emission reduction options. These are described below. See also Section IV.B.1 above.

1. Highly Efficient Generation Technology (*e.g.,* Supercritical or Ultra-supercritical Boilers)

In the January 2014 proposal, we considered whether 'Highly Efficient New Generation without CCS Technology' should constitute the BSER for new steam generating units. 79 FR at 1468–69. The discussion focused on the performance of highly efficient generation technology (that does not include any implementation of CCS), such as a supercritical[507] pulverized coal (SCPC) or a supercritical CFB boiler, or a modern, well-performing IGCC unit.

All these options are technically feasible—there are numerous examples of each operating in the U.S. and worldwide. However, we do not find them to qualify as the best system for reduction of CO_2 emissions for the following reasons:

a. Lack of Significant CO_2 Reductions When Compared to Business as Usual

At the outset, we reviewed the emission rates of efficient PC and CFB units. According to the DOE/NETL estimates, a newly constructed subcritical PC unit firing bituminous coal would emit approximately 1,800 lb CO_2/MWh-g,[508] a new highly efficient SCPC unit using bituminous coal would emit nearly 1,720 lb CO_2/MWh-g, and a new IGCC unit would emit about 1,430 lb CO_2/MWh-g.[509] [510] Emissions from comparable sources utilizing sub-bituminous coal or lignite will have somewhat higher CO_2 emissions.[511]

Some commenters noted that new coal-fired plants utilizing supercritical boiler design or IGCC would provide substantial emission reductions compared to the emissions from the existing subcritical coal plants that are currently in wide use in the power sector. However, most of the recent new power sector projects using solid fossil fuel (coal or petroleum coke) as the primary fuel—both those that have been constructed and those that have been proposed—are supercritical boilers and IGCC units. About 60 percent of new coal-fired utility boiler capacity that has come on-line since 2005 was supercritical and of the new capacity that came on-line since 2010, about 70 percent was supercritical. No new coal-fired utility boilers began operation in either 2013 or 2014. Coal-fired power plants that have come on-line most recently include AEP's John W. Turk, Jr. Power Plant, which is a 600 MW ultra-supercritical[512] PC (USCPC) facility located in the southwest corner of Arkansas, and Duke Energy's Edwardsport plant, which is a 618 MW

[505] ''From Lubbock, TX to Thompsons, TX—Amine Scrubbing for Commercial CO_2 Capture from Power Plants'', plenary address by Prof. Gary Rochelle at the 12th International Conference on Greenhouse Gas Technology (GHGT–12), Austin, TX (October 2014).

[506] The EPA also finds that the standards would not result in any significant impact on solid waste generation or management. See Section XII.D below.

[507] Subcritical coal-fired boilers are designed and operated with a steam cycle below the critical point of water. Supercritical coal-fired boilers are designed and operated with a steam cycle above the critical point of water. Increasing the steam pressure and temperature increases the amount of energy within the steam, so that more energy can be extracted by the steam turbine, which in turn leads to increased efficiency and lower emissions.

[508] Exhibit ES–2 from ''Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity'', Revision 2, Report DOE/NETL–2010/1397 (November 2010).

[509] ''Cost and Performance Baseline for Fossil Energy Plants Supplement: Sensitivity to CO_2 Capture Rate in Coal-Fired Power Plants'', DOE/NETL–2015/1720 (June 2015); SCPC rates come from Exhibit A–2 and IGCC rates come from Exhibit A–4.

[510] The comparable emissions on a net basis are: subcritical PC—1,890 lb CO_2/MWh-n; SCPC–1,705 lb CO_2/MWh-n; and IGCC—1,724 lb CO_2/MWh-n. (See same references as for gross emissions provided in the text).

[511] Exhibit ES–2 from ''Cost and Performance Baseline for Fossil Energy Plants Volume 3b: Low Rank Coal to Electricity: Combustion Cases'', Report DOE/NETL–2010/1463 (March 2011).

[512] Ultra-supercritical (U.S.C.) and advanced ultra-supercritical (A–U.S.C.) are terms often used to designate a coal-fired power plant design with steam conditions well above the critical point.

''CCS ready'' [513] IGCC unit located in Knox County, Indiana. Both of those facilities came on-line in 2012. It is likely that the units that initiated operation in 2010 or later were conceived of, planned, designed, and permitted well before 2010—likely in the early 2000s. Thus, it seems clear that the power sector had already, at that point, transitioned to the selection of supercritical boiler technology as ''business as usual'' for new coal-fired power plants. Since that time, there have been other coal-fired power plants that have been proposed and almost all of them have been either supercritical boiler designs or IGCC units. In Table 1 of the Technical Support Document *Fossil Fuel-Fired Boiler and IGCC EGU Projects Under Development: Status and Approach* [514] for the January 2014 proposal, the EPA listed the development status of ''potential transitional sources'' (*i.e.,* projects that had been proposed and had received Prevention of Significant Deterioration (PSD) preconstruction permits as of April 13, 2012). Of the 16 proposed EGU projects in Table 1—most of which have been cancelled or converted to or replaced with NGCC projects—the majority (nine) are either supercritical PC or IGCC designs. Five of the proposed projects were CFB designs with only one being a subcritical PC design.

The EPA is aware of only one new coal-fired power plant that is actively in the construction phase. That plant is Mississippi Power's Kemper County Energy Facility in Kemper County, MS—an IGCC unit that plans to begin operations in 2016 and will implement partial CCS to capture approximately 65 percent of the available CO_2, which will be sold for use in EOR operations.

Considering the direction that the power sector has been taking and the changes that it is undergoing, identifying a new supercritical unit as the BSER and requiring an emission limitation based on the performance of such units thus would provide few, if any, additional CO_2 emission reductions beyond the sector's ''business as usual''. As noted, for the most part, new sources are already designed to achieve at least that emission limitation. This criterion does not itself eliminate supercritical technology from consideration as BSER. However, existing technologies must be considered in the context of the range of technically feasible technologies and, as we discuss elsewhere in this final preamble, partial CCS can achieve emission limitations beyond business as usual and do so at a reasonable cost.

The EPA also considered IGCC technology and whether it represents the BSER for new power plants utilizing coal or other solid fossil fuels. IGCC units, on a gross-output basis, have inherently lower CO_2 emission rates when compared to similarly-sized SCPC units. However, the net emission rates and overall emissions to the atmosphere (*i.e.,* tons of CO_2 per year) tend to be more similar (though still somewhat lower) for new IGCC units when compared to new SCPC units with the same electrical output. Therefore an emission limitation based on the expected performance of a new IGCC unit would result in some CO_2 emission reductions from the segment of the industry that would otherwise construct new PC units, but not from the segment of the industry that would already construct new IGCC units. A gross-output-based emission limitation consistent with the expected performance of a new IGCC unit would still require some additional control, such as partial CCS, on a new supercritical boiler.

As is shown in Section V.J and H, additional emission reductions beyond those that would result from an emission standard based on a new SCPC boiler or even a new IGCC unit as the BSER can be achieved at a reasonable cost. Because practicable emission controls are available that are of reasonable cost at the source level and that will have little cost and energy impact at the national level, the EPA is according significant weight to the factor of amount of emissions reductions in determining the BSER. As discussed above, the D.C. Circuit has emphasized this factor in describing the purpose of CAA section 111 as to achieve ''as much [emission reduction] as practicable.'' [515]

b. Lack of Incentive for Technological Innovation

As discussed above, the EPA is justifying its identification of the BSER based on its weighing of the factors explicitly identified in CAA section 111(a)(1), including the amount of the emission reduction. Under the D.C. Circuit case law, encouraging the development and implementation of advanced control technology must also be considered (and, in any case, may reasonably be considered; see Section V.H.3.d above). Consideration of this factor confirms the EPA's decision not to identify highly efficient generation technology (without CCS) as the BSER. At present, CCS technologies are the most promising options to achieve significant reductions in CO_2 emissions from newly constructed fossil fuel-fired steam generating units. CCS technology is also now a viable retrofit option for some modified, reconstructed and existing sources—depending upon the configuration, location and age of those sources. As CCS technologies are deployed and used more there is an expectation that, based on previous experience with advanced technologies, the performance will improve and the implementation costs will decline. The improved performance and lower costs will provide additional incentive for further implementation in the future.

The Intergovernmental Panel on Climate Change (IPCC) recently released its Fifth Assessment report, [516] which recognizes that widespread deployment of CCS is crucial to reach the long term climate goals. The authors of the report used models to predict the likelihood of stabilizing the atmospheric concentration of CO_2 at 450 ppm by 2050 with or without carbon capture and storage (CCS). They found that several of the models were not able to reach this goal without CCS, which underlines the importance of deploying and further developing CCS on a large scale.

American Electric Power (AEP), in an evaluation of lessons learned from the Phase 1 of its Mountaineer CCS project, wrote: ''AEP still believes the advancement of CCS is critical for the sustainability of coal-fired generation.'' [517]

Some commenters felt that the proposed standard of performance for new steam generating units, based on implementation of partial CCS at an emission rate of 1,100 lb/MWh-g, would not serve to promote the increased deployment and implementation of CCS. The commenters argued that such a standard could instead have the unintended result of discouraging the further development of advanced coal generating technologies such as ultra-supercritical boilers and improved IGCC designs.

Commenters further argued that such a standard will stifle further

[513] A ''CCS ready'' facility is one that is designed such that the CCS equipment can be more easily added at a later time.

[514] Available in the rulemaking docket (entry: EPA–HQ–OAR–2013–0495–0024).

[515] *Sierra Club,* 657 F.2d at 327 & n. 83.

[516] IPCC, Working Group III, Climate Change 2014: Mitigation of Climate Change, *http://mitigation2014.org/report/publication/.*

[517] CCS LESSONS LEARNED REPORT American Electric Power Mountaineer CCS II Project Phase 1, Prepared for The Global CCS Institute Project # PRO 004, January 23, 2012, page 2. See also AEP FEED Study at pp. 4, 63 (same). Available at: *http://www.globalccsinstitute.com/publications/aep-mountaineer-ii-project-front-end-engineering-and-design-feed-report.*

development of CCS technologies. Commenters felt that the standard would effectively deter the construction of new coal-fired generation—and, if there is no new coal-fired generation, then there will be no implementation of CCS technology and, therefore, no need for continued research and development of CCS technologies. They argued, in fact, that the best way to promote the development of CCS was to set a standard that did not rely on it.

The EPA does not agree with these arguments and, in particular, does not see how a standard that is not predicated on performance of an advanced control technology would serve to promote development and deployment of that advanced control technology. On the contrary, the history of regulatory actions has shown that emission standards that are based on performance of advanced control equipment lead to increased use of that control equipment, and that the absence of a requirement stifles technology development.

There is a dramatic instance of this paradigm presented in the present record. In 2011, AEP deferred construction of a large-scale CCS retrofit demonstration project on one of its coal-fired power plants because the state's utility regulators would not approve cost recovery for CCS investments without a regulatory requirement to reduce CO_2 emissions. AEP's chairman was explicit on this point, stating in a July 17, 2011 press release announcing the deferral:

We are placing the project on hold until economic and policy conditions create a viable path forward . . . We are clearly in a classic 'which comes first?' situation. The commercialization of this technology is vital if owners of coal-fueled generation are to comply with potential future climate regulations without prematurely retiring efficient, cost-effective generating capacity. But as a regulated utility, it is impossible to gain regulatory approval to recover our share of the costs for validating and deploying the technology without federal requirements to reduce greenhouse gas emissions already in place. The uncertainty also makes it difficult to attract partners to help fund the industry's share.[518]

Some commenters also argued that the incremental cost associated with including CCS at the proposed level would prevent new coal-fired units from being built. Instead, they advocated for a standard based on most efficient technology (supercritical) coupled with government subsidies to advance and promote CCS technology. The final standard is less stringent than that proposed, and can be met at a lower cost than the proposed standard, and as explained above in Section V.H, the EPA has carefully evaluated those costs and finds them to be reasonable. Further, the record and current economic conditions (fuel costs, renewables, demand growth, etc.) show that non-economic factors such as a desire for fuel diversity will likely drive future development of any new coal-fired EGUs. For this reason, the EPA does not find the commenters' bare assertions that the incremental cost of CCS (particularly as reasonably modulated for this final standard) would make the difference between constructing and not constructing new coal capacity to be persuasive. Rather, a cost-reasonable standard reflecting use of the new technology is what will drive new technology deployment.

The EPA expects that it is unlikely that a new IGCC unit would install partial CCS to meet the final standard unless the facility is built to take advantage of EOR opportunities or to operate as a poly-generation facility (*i.e.,* to co-produce power along with chemicals or other products). For new IGCC units, the final standard of performance can be met by co-firing a small amount of natural gas. Some commenters argued that IGCC is an advanced technology that, like CCS, should be promoted. The EPA agrees. IGCC is a low-emitting, versatile technology that can be used for purposes beyond just power production (as mentioned just above). Commenters further argued that a requirement to include partial CCS (at a level to meet the proposed standard of performance) would serve to deter—rather than promote—more installation of IGCC technology. We disagree with a similar argument that commenters make with respect to partial CCS for post-combustion facilities, but our final standard moots that argument for IGCC facilities because the final emission limitation of 1,400 lb CO_2/MWh-g will not itself deter installation of IGCC technology, by the terms of the commenters' own argument.

2. ''Full'' Carbon Capture and Storage (*i.e.,* 90 Percent Capture)

We also reconsidered whether the emission limitation for new coal-fired EGUs should be based on the performance of full implementation of CCS technology. For a newly constructed utility boiler, this would mean that a post-combustion capture system would be used to treat the entire flue gas stream to achieve an approximately 90 percent reduction in CO_2 emissions. For a newly constructed IGCC unit, a pre-combustion capture system would be used to capture CO_2 from a fully shifted gasification syngas stream to achieve an approximately 90 percent reduction in CO_2 emissions.

In the proposal for newly constructed sources, we found that ''full CCS'' would certainly result in significant CO_2 reductions from any new source implementing the technology. However, we also found that the costs associated with implementation, on either a new utility boiler system or a new IGCC unit, are predicted to substantially exceed the costs for other dispatchable non-NGCC generating options that are being considered by utilities and project developers (*e.g.,* new nuclear plants and new biomass-fired units). See 79 FR at 1477. This remains the case, and indeed, the difference between cost of full capture and new nuclear technology is estimated to be even greater than at proposal. The EPA thus is not selecting full capture CCS as BSER.

Q. Summary

The EPA finds that the best system of emission reduction adequately demonstrated is a highly efficient supercritical pulverized coal boiler using post-combustion partial CCS so that CO_2 is captured, compressed and safely stored over the long-term. Properly designed, operated, and maintained, this best system can achieve a standard of performance of 1,400 lb CO_2/MWh-g, an emission limitation that is achievable over the 12-operating-month compliance period considering usual operating variability (including use of different coal types, periods of startup and shutdown, and malfunction conditions). This standard of performance is technically feasible, given that the BSER technology is already operating reliably in full-scale commercial application. The technology adds cost to a new facility which the EPA has evaluated and finds to be reasonable because the costs are in the same range as those for new nuclear generating capacity—a competing non-NGCC, dispatchable technology that utilities and project developers are also considering for base load application. The EPA has also considered capital cost increases associated with use of post-combustion partial CCS at the level needed to meet the final standard and found them to be reasonable, and within the range of capital cost increases for this industry in prior NSPS which have been adjudicated as reasonable. The EPA's consideration of costs is also informed by its judgment that new coal-

[518] *http://www.aep.com/newsroom/newsreleases/?id=1704.*

fired capacity would be constructed not as the most economic option, but for such purposes as preserving fuel diversity in an energy portfolio, and so would not be cost competitive with natural gas-fired capacity, so that some additional cost premium may therefore be reasonable. The EPA has carefully evaluated the non-air quality health and environmental impacts of the final standard and found them to be reasonable: CO_2 pipelines and CO_2 sequestration via deep well injection are subject already to rigorous control under established regulatory programs which assure prevention of environmental release during transport and storage. In addition, water use associated with use of partial CCS at the level to meet the final standard is acceptable, and use of the technology does not impose significant burdens on energy requirements at either the plant or national level. The 1,400 lb CO_2/MWh-g standard reflecting performance of the BSER may be achieved without geographic constraint, both because geologic sequestration and EOR capacity are widely available and accessible, and also because alternative compliance pathways are available in the unusual circumstance where a new coal-fired plant is sited in an area without such access, that area has not already limited construction of new coal-fired capacity in some way, and the area cannot be serviced by coal-by-wire. Accordingly, the EPA finds that the promulgated standard of performance for new fossil fuel-fired steam electric generating units satisfies the requirements of CAA section 111(a).

VI. Rationale for Final Standards for Modified Fossil Fuel-Fired Electric Utility Steam Generating Units

The EPA has determined that, as proposed, the BSER for steam generating units that trigger the modification provisions is each affected unit's own best potential performance as determined by that unit's historical performance. The final standards of performance are similar to those proposed in the June 2014 proposal. Differences between the proposed standards and the final standards issued in this action reflect responses to comments received on the proposal. Those changes are described below.

As noted previously, the EPA is issuing final emission standards only for affected modified steam generating units that conduct modifications resulting in a hourly increase in CO_2 emissions (mass per hour) of more than 10 percent (''large'' modifications). The EPA is continuing to review the appropriate standards for modified sources that conduct modifications resulting in a hourly increase in CO_2 emissions (mass per hour) of less than or equal to 10 percent (''small'' modifications), is not issuing final standards for those sources in this action, and is withdrawing the proposed standards for those sources. See Section XV below.

A. Rationale for Final Applicability Criteria for Modified Steam Generating Units

Final applicability criteria for modified steam generating EGUs include those discussed earlier in Section III.A.1 (General Applicability) and Section III.A.3 (Applicability Specific to Modified Sources).

CAA section 111(a)(4) defines a ''modification'' as ''any physical change in, or change in the method of operation of, a stationary source'' that either ''increases the amount of any air pollutant emitted by such source or . . . results in the emission of any air pollutant not previously emitted.'' Certain types of physical or operational changes are exempt from consideration as a modification. Those are described in 40 CFR 60.2, 60.14(e). To be clear, our action in this final rule, and the discussion below, does not change anything concerning what constitutes or does not constitute a modification under the CAA or the EPA's regulations.[519]

A modified steam generating unit is a source that fits the definition and applicability criteria of a fossil fuel-fired steam generating unit and that commences a qualifying modification on or after June 18, 2014 (the publication date of the proposed modification standards). 79 FR 34960.

For the reasons discussed below, the EPA in this final action is finalizing requirements only for steam generating units that conduct modifications resulting in an increase in hourly CO_2 emissions (mass per hour) of more than 10 percent as compared to the source's highest hourly emission during the previous five years. With respect to modifications with smaller increases in CO_2 emissions (specifically, steam generating units that conduct modifications resulting in an increase in hourly CO_2 emissions (mass per hour) of 10 percent or less compared to the source's highest hourly emission during the previous 5 years), the EPA is not finalizing any standard or other requirements, and is withdrawing the June 2014 proposal with respect to these sources (see Section XV below).

[519] CAA section 111(a)(4); See also 40 CFR 60.14 concerning what constitutes a modification, how to determine the emission rate, how to determine an emission increase, and specific actions that are not, by themselves, considered modifications.

The effect of the EPA's deferral on setting standards for sources undertaking modifications resulting in smaller increases in CO_2 emissions and the withdrawal of the June 2014 proposal with respect to such sources is that such sources will continue to be existing sources and subject to requirements under section 111(d). This is because an existing source does not always become a new source when it modifies. Under the definition of ''new source'' in section 111(a)(2), an existing source only becomes a new source if it modifies after the publication of proposed or final regulations that will be applicable to it. Thus, if an existing source modifies at a time that there is no promulgated final standard or pending proposed standard that will be applicable to it as a modified ''new'' source, that source is not a new source and continues to be an existing source. Here, because the EPA is not finalizing standards for sources undertaking modifications resulting in smaller increases in CO_2 emissions and is withdrawing the proposal with respect to such sources, these sources do not fall within the definition of ''new source'' in section 111(a)(2) and continue to be an ''existing source'' as defined in section 111(a)(6). See Section XV below.

As we discussed in the June 2014 proposal, the EPA has historically been notified of only a limited number of NSPS modifications[520] involving fossil steam generating units and therefore predicted that very few of these units would trigger the modification provisions and be subject to the proposed standards. Given the limited information that we have about past modifications, the agency has concluded that it lacks sufficient information to establish standards of performance for all types of modifications at steam generating units at this time. Instead, the EPA has determined that it is appropriate to establish standards of performance at this time for larger modifications, such as major facility upgrades involving, for example, the refurbishing or replacement of steam turbines and other equipment upgrades that result in substantial increases in a unit's hourly CO_2 emissions rate. The agency has determined, based on its review of public comments and other publicly available information, that it has adequate information regarding the types of modifications that could result in large increases in hourly CO_2 emissions, as well as on the types of

[520] NSPS modifications resulting in increases in hourly emissions of criteria pollutants.

measures available to control emissions from sources that undergo such modifications, and on the costs and effectiveness of such control measures, upon which to establish standards of performance for modifications with large emissions increases at this time.

In establishing standards of performance at this time for modifications with large emissions increases, but not for those with small increases, the EPA is exercising its policy discretion to promulgate regulatory requirements in a sequential fashion for classes of modifications within a source category, accounting for the information available to the agency, while also focusing initially on those modifications with the greatest potential environmental impact. This approach is consistent with the case law that authorizes agencies to establish a regulatory framework in an incremental fashion, that is, a step at a time.[521]

To be clear, the EPA is not reaching a final decision as to whether it will regulate modifications with smaller increases, or even that such modifications should be subject to different requirements than we are finalizing in this rule for the modifications with larger increases. We have made no decisions and this matter is not concluded. We plan to continue to gather information, consider the options for modifications with smaller increases, and, in the future, develop a proposal for these modifications or otherwise take appropriate steps.

As a means of determining the proper threshold between the larger and smaller increases in CO_2 emissions, the EPA examined changes in CO_2 emissions that may result from large, capital-intensive projects, such as major facility upgrades involving the refurbishing or replacement of steam turbines and other equipment upgrades that would significantly increase a unit's capacity to burn more fossil fuel, thereby resulting in large emissions increases. Major upgrades such as these could increase a steam generating unit's hourly CO_2 emissions by well over 10 percent.[522]

An example of such major upgrade would be work performed at AmerenUE's Labadie Plant, a facility with four 600–MW (nominal) coal-fired units located 35 miles west of St. Louis. In the early 2000s, plant staff conducted process improvements that raised maximum unit capacity by nearly 10 percent (from 580 MW to 630 MW).[523] Those changes included boiler improvements necessitated by its switch from bituminous to subbituminous coal,[524] installation of low-NO_X burners, an overfire air system, and advanced computer controls. One of the performance gains came from upgrading all four steam turbines, which AmerenUE chose to replace as modules allowing engineers more freedom to maximize performance unconstrained by the units' existing outer casing.

Another example is the refurbishment of the 2,100 MW Eskom Arnot coal-fired power plant in South Africa with a resulting increase in its power output by 300 MW to 2,400 MW—an increase in capacity of 14 percent.[525] For each of the plant's six steam generating units, the company conducted a complete retrofit of the high pressure and intermediate pressure steam turbines, a capacity upgrade of the low pressure steam turbine, and the replacement and upgrade of associated turbine side pumps and auxiliaries. In addition, major upgrades to the boiler plant were conducted, including supply of new pressure part components, new burners, and modification to other equipment such as the coal mills and classifiers, fans, and heaters. Other examples are provided in a technical memo available in the rulemaking docket.[526]

The EPA does not intend to imply that these specific projects would have resulted in an increase in hourly CO_2 emissions of greater than 10 percent. Capacity increases are often the result of efficient improvements or are accompanied by other facility improvements that can offset emissions increases due to increased fuel input capacity. However, these examples are intended to show the types of large, more capital intensive projects that can potentially result in increases in hourly emissions of CO_2 of at least 10 percent.

The EPA believes that it is reasonable to set the threshold between ''large'' modifications and ''small'' modifications at 10 percent, a level commensurate with the magnitude of the emissions increases that could result from the types of projects described above, and we are issuing a final standard of performance for those sources that conduct modifications resulting in hourly CO_2 emission increases that exceed that threshold. We are not issuing standards of performance for those sources that conduct modifications resulting in an hourly increase of CO_2 emissions of less than or equal to 10 percent.

Therefore, the EPA is withdrawing the proposed standards for those sources that conduct modifications resulting in a hourly increase in CO_2 emissions (mass per hour) of less than or equal to ten percent and is not issuing final standards for those sources at this time. See Section XV below. Utilities, states and others should be aware that the differentiation between modifications with larger and smaller increases in CO_2 emissions only applies to sources covered under 40 CFR part 60, subpart TTTT, *i.e.,* it is only applicable to CO_2 emissions from fossil fuel-fired steam generating units. There is no similar provision for criteria pollutants or for other source categories. Utilities, states and others should also be aware that the distinction between large and small modifications only applies to NSPS modifications. Sources undertaking modifications may still be subject to requirements of New Source Review under CAA Title I part C or D (which have different standards for modifications than the NSPS and require a case-by-case analysis) or other CAA requirements.

The EPA notes that some commenters expressed concern that a number of existing fossil steam generating units, in order to fulfill requirements of an approved CAA section 111(d) plan, may pursue actions that involve physical or operational changes that result in some increase in their CO_2 emissions on an hourly basis, and thus constitute

[521] As the U.S. Supreme Court recently stated in *Massachusetts* v. *EPA,* 549 U.S. 497, 524 (2007): '' 'Agencies, like legislatures, do not generally resolve massive problems in one fell regulatory swoop;' '' and instead they may permissibly implement such regulatory programs over time, '' 'refining their preferred approach as circumstances change and as they develop a more nuanced understanding of how best to proceed.' '' *See Grand Canyon Air Tour Coalition* v. *F.A.A.,* 154 F.3d 455 (D.C. Cir. 1998), *City of Las Vegas* v. *Lujan,* 891 F.2d 927, 935 (D.C. Cir. 1989), *National Association of Broadcasters* v. *FCC,* 740 F.2d 1190, 1209–14 (D.C. Cir. 1984). See also, *Hazardous Waste Treatment Council* v. *U.S. E.P.A.*, 861 F.2d 277, 287 (D.C. Cir. 1988) (''[A]n agency's failure to regulate more comprehensively is not ordinarily a basis for concluding that the regulations already promulgated are invalid. 'The agency might properly take one step at a time.' *United States Brewers Assoc.* v. *EPA,* 600 F.2d 974,982 (D.C. Cir. 1979). Unless the agency's first step takes it down a path that forecloses more comprehensive regulation, the first step is not assailable merely because the agency failed to take a second. The steps may be too plodding, but that raises an entirely different issue . . . .'').

[522] See *e.g.,* Power Engineering, Steam Turbine Upgrades Boost Plant Reliability, Efficiency, available at *www.power-eng.com/articles/print/volume-116/issue-11/features/steam-turbine-upgrades-boost-plant-reliability-efficiency.html.*

[523] ''Steam turbine upgrading: Low-hanging fruit'', Power (04/15/2006), *www.powermag.com/steam-turbine-upgrading-low-hanging-fruit.*

[524] Note that a change in coal-type or change in the use of other raw material does not necessarily constitute an ''operational change''. See 40 CFR 60.14(e)(4).

[525] *www.alstom.com/press-centre/2006/10/alstom-signs-power-plant-upgrade-and-retrofit-contract-with-eskom-in-south-africa/.*

[526] See ''U.S. DOE Information Relevant to Technical Basis for ''Large Modification'' Threshold'' available in the rulemaking docket EPA–HQ–OAR–2013–0495.

modifications. Some commenters suggested that the EPA should exempt projects undertaken specifically for the purpose of complying with CAA section 111(d).

The EPA does not have sufficient information at this time to predict the full array of actions that existing steam generating units may undertake in response to applicable requirements under an approved CAA section 111(d) plan, or which, if any, of these actions may result in increases in CO_2 hourly emissions. Nevertheless, the EPA expects that, to the extent actions undertaken by existing steam generating units in response to 111(d) requirements trigger modifications, the magnitude of the increases in hourly CO_2 emissions associated with such modifications would generally be smaller and would therefore generally not subject such modifications to the standards of performance that the EPA is finalizing in this rule for modified steam generating units with larger increases in hourly CO_2 emissions.

B. Identification of the Best System of Emission Reduction

The EPA has determined that, as was proposed, the BSER for steam generating units that trigger the modification provisions is the affected EGU's own best potential performance as determined by that source's historical performance.

The EPA proposed that the BSER for modified steam generating EGUs is each unit's own best potential performance based on a combination of best operating practices and equipment upgrades. Specifically, the EPA co-proposed two alternative standards for modified utility steam generating units. In the first co-proposed alternative, modified steam generating EGUs would be subject to a single emission standard determined by the affected EGU's best demonstrated historical performance (in the years from 2002 to the time of the modification) with an additional 2 percent emission reduction. The EPA proposed that the standard could be met through a combination of best operating practices and equipment upgrades. To account for facilities that have already implemented best practices and equipment upgrades, the proposal also specified that modified facilities would not have to meet an emission standard more stringent than the corresponding standard for reconstructed EGUs.

The EPA also co-proposed that the specific standard for modified sources would be dependent on the timing of the modification. We proposed that sources that modify prior to becoming subject to a CAA section 111(d) plan would be required to meet the same standard described in the first co-proposal—that is, the modified source would be required to meet a unit-specific emission limit determined by the affected EGU's best demonstrated historical performance (in the years from 2002 to the time of the modification) with an additional 2 percent emission reduction (based on equipment upgrades). We also proposed that sources that modify after becoming subject to a CAA section 111(d) plan would be required to meet a unit-specific emission limit that would be determined by the CAA section 111(d) implementing authority and would be based on the source's expected performance after implementation of identified unit-specific energy efficiency improvement opportunities.

The final standards in this action do not depend upon when the modification commences (as long as it commences after June 8, 2014). The EPA received comments on the June 2014 proposal that called into question the need to differentiate the standard based on when the modification was undertaken. Further, commenters noted that the proposed requirements for sources modifying after becoming subject to a CAA section 111(d) plan, which were based on energy efficiency improvement opportunities were vague and that standard setting under CAA section 111(b) is a federal duty and would require notice-and-comment rulemaking. The EPA considered those comments and has determined that we agree that there is no need for subcategories based on the timing of the modification.

C. BSER Criteria

1. Technical Feasibility

The EPA based technical feasibility of the unit-specific efficiency improvement on analyses done to support heat rate improvement for the proposed CAA section 111(d) emission guidelines (Clean Power Plan). That work was summarized in Chapter 2 of the TSD, ''GHG Abatement Measures''.[527] In response to comments on the proposed Clean Power Plan, the approach was adjusted, as described in the final CAA section 111(d) emission guidelines. As with proposed actions, the EPA is basing technical feasibility for final standards for modified source efficiency improvements on the analyses for heat rate improvements for the CAA 111(d) final rule.

[527] Technical Support Documents ''GHG Abatement Measures'' (proposal) and ''GHG Mitigation Measures'' (final) available in the rulemaking docket EPA–HQ–OAR–2013–0495.

2. Cost

Any efficiency improvement made by EGUs for the purpose of reducing CO_2 emissions will also reduce the amount of fuel that EGUs consume to produce the same electricity output. The cost attributable to CO_2 emission reductions, therefore, is the net cost of achieving heat rate improvements after any savings from reduced fuel expenses. As summarized below, we estimate that, on average, the savings in fuel cost associated with a 4 percent heat rate improvement would be sufficient to cover much of the associated costs, and thus that the net costs of heat rate improvements associated with reducing CO_2 emissions from affected EGUs are relatively low.

We recognize that our cost analysis just described will represent the costs for some EGUs better than others because of differences in EGUs' individual circumstances. We further recognize that reduced generation from coal-fired EGUs will tend to reduce the fuel savings associated with heat rate improvements, thereby raising the effective cost of achieving the CO_2 emission reductions from the heat rate improvements. Nevertheless, we still expect that the majority of the investment required to capture the technical potential for CO_2 emission reductions from heat rate improvements would be offset by fuel savings, and that the net costs of implementing heat rate improvements as an approach to reducing CO_2 emissions from modified fossil fuel-fired EGUs are reasonable. The EPA further notes that the types of large, more capital intensive projects that may trigger the ''larger modifications'' threshold (*i.e.,* result in an hourly increase in CO_2 emissions of more than 10 percent) often are undertaken in order to increase the capacity of the source but also to improve the heat rate or efficiency of the unit.

3. Emission Reductions

This approach would achieve reasonable reductions in CO_2 emissions from the affected modified units as those units will be required to meet an emission standard that is consistent with more efficient operation. In light of the limited opportunities for emission reductions from retrofits, these reductions are adequate.

4. Promotion of Technology and Other Systems of Emission Reduction

As noted previously, the case law makes clear that the EPA is to consider the effect of its selection of the BSER on technological innovation or development, but that the EPA also has the authority to weigh this factor, along with the various other factors. With the selection of emissions controls, modified sources face inherent constraints that newly constructed greenfield and even reconstructed sources do not; as a result, modified sources present different, and in some ways more limited, opportunities for technological innovation or development. In this case, the standards promote technological development by promoting further development and market penetration of equipment upgrades and process changes that improve plant efficiency.

VII. Rationale for Final Standards for Reconstructed Fossil Fuel-Fired Electric Utility Steam Generating Units

A. Rationale for Final Applicability Criteria for Reconstructed Sources

The applicability rationale for reconstructed utility steam generating units is the same as for newly constructed utility steam generating units. We are finalizing the same general criteria and not amending the reconstruction provisions included in the general provisions.

B. Identification of the Best System of Emission Reduction

In the proposal, the EPA evaluated seven different control technology configurations to determine the BSER for reconstructed fossil fuel-fired boiler and IGCC EGUs: (1) The use of partial CCS, (2) conversion to (or co-firing with) natural gas, (3) the use of CHP, (4) hybrid power plants, (5) reductions in generation associated with dispatch changes, renewable generation, and demand side energy efficiency, (6) efficiency improvements achieved through the use of the most efficient generation technology, and (7) efficiency improvements achieved through a combination of best operating practices and equipment upgrades.

Although the EPA concluded that the first 4 technologies met most of the evaluation criteria, namely they are adequately demonstrated, have reasonable costs and provide GHG emissions reductions, they were inappropriate for BSER due to site specific constraints for existing EGUs on a nationwide basis. We rejected best operating practices and equipment upgrades because we concluded the GHG reductions are not sufficient to qualify as BSER. The majority of commenters agree with the EPA's decision that these technologies are not BSER. In contrast, as described in more detail later in this section a few commenters did support partial CCS as BSER.

The fifth option, reductions in generation associated with dispatch changes, renewable generation, and demand side energy efficiency, is comparable to application of measures identified in building blocks two, three and four in the emissions guidelines that we proposed under CAA section 111(d). We solicited comment on any additional considerations that the EPA should take into account in the applicability of building blocks two, three and four in the BSER determination. Most commenters stated that building blocks two, three and four should not be considered for reconstructed sources.

The proposed BSER was based on the performance of the most efficient generation technology available, which we concluded was the use of the best available subcritical steam conditions for small units and the use of supercritical steam conditions for large units. We concluded this technology to be technically feasible, to have sufficient emission reductions, to have reasonable costs, and some opportunity for technological innovation. The proposed emission standard for these sources was 1,900 lb CO_2/MWh-n for units with a heat input rating of greater than 2,000 MMBtu/h and 2,100 lb CO_2/MWh-n for units with a heat input rating of 2,000 MMBtu/h or less. The difference in the proposed standards for larger and smaller units was based on greater availability of higher pressure/temperature steam turbines (*e.g.* supercritical steam turbines) for larger units. As explained in Section III of this preamble, we are finalizing the standard on a gross output basis for utility steam generating units. The equivalent gross-output-based standards are 1,800 lb CO_2/MWh and 2,000 lb CO_2/MWh respectively.

We solicited comment on multiple aspects of the proposed standards. First, we solicited comment on a range of 1,600 to 2,000 lb CO_2/MWh-g for large units and 1,800 to 2,200 lb CO_2/MWh-g for small units. We also solicited comment on whether the standards for utility boilers and IGCC units should be subcategorized by primary fuel type. In addition, we solicited comment on if there are sufficient alternate compliance technologies (*e.g.,* co-firing natural gas) that the small unit subcategory is unnecessary and should be eliminated. Those small sources would be required to meet the same emission standard as large utility boilers and IGCC units.

Many commenters supported the upper limits of the suggested ranges, saying the standard will be consistently met. Some commenters raised concerns about the achievability of these limits for the many boiler and fuel types. A few commenters suggested that there should be separate subcategories for coal-fired utility boilers and IGCC units, since IGCC units have demonstrated limits closer to 1,500 lb CO_2/MWh-n and the units' designs are so fundamentally different. Some commenters said that CFB (due to lower maximum steam temperatures), IGCC, and traditional boilers each need their own subcategory. Some commenters suggested that due to high moisture content and high relative CO_2 emissions of lignite, lignite-fired units should have its own subcategory. Other commenters opposed the proposed standards for reconstructed units because they thought the BSER determination for reconstructed subpart Da units was inconsistent with the BSER determination for newly constructed units. These commenters stated that the EPA did not provide sufficient justification for eliminating partial carbon capture and sequestration (CCS). These commenters also stated that the reason the EPA gave for dismissing CCS in the proposal was a lack of ''sufficient information about costs.'' These commenters hold that the cost rationale does not apply for reconstructed coal-fired power plants. The fact that reconstructed units may face greater costs to comply with a CAA section 111(b) standard than new sources does not relieve them of their compliance obligation.

Based on a review of the comments, we have concluded that both the proposed BSER and emission standards are appropriate, and we are finalizing the standards as proposed. Nothing in the comments changed our view that the BSER for reconstructed steam generating units should be based on the performance of a well operated and maintained EGU using the most efficient generation technology available, which we have concluded is a supercritical pulverized coal (SCPC) or supercritical circulating fluidized bed (CFB) boiler for large units, and subcritical for small units. As described at proposal, we have concluded that these standards are achievable by all the primary coal types. The final standards for reconstructed utility boilers and IGCC units is 1,800 lb CO_2/MWh-g for sources with a heat input rating of greater than 2,000 MMBtu/h and 2,000 lb CO_2/MWh-g for sources with a heat input rating of 2,000 MMBtu/h or less.

While the final emission standards are based on the identified BSER, a reconstructed EGU would not necessarily have to rebuild the boiler to use steam temperatures and pressures that are higher than the original design. As commenters noted, a reconstructed unit is not required to meet the standards if doing so is deemed to be ''technologically and economically'' infeasible. 40 CFR 60.15(b). This provision inherently requires case-by-case reconstruction determinations in the light of considerations of economic and technological feasibility. However, this case-by-case determination would consider the identified BSER (the use of the best available steam conditions), as well as—at a minimum—the first four technologies the EPA considered, but rejected, as BSER for a nationwide rule. One or more of these technologies could be technically feasible and reasonable cost, depending on site specific considerations and, if so, would likely result in sufficient GHG reductions to comply with the applicable reconstructed standards. Finally, in some cases, equipment upgrades and best operating practices would result in sufficient reductions to achieve the reconstructed standards.

VIII. Summary of Final Standards for Newly Constructed and Reconstructed Stationary Combustion Turbines

This section summarizes the final applicability requirements, BSER determinations, and emission standards for newly constructed and reconstructed stationary combustion turbines. In addition, it also summarizes significant differences between the proposed and final provisions.

A. Applicability Requirements

We are finalizing BSER determinations and emission standards for newly constructed and reconstructed stationary combustion turbines that (1) have a base load rating for fossil fuels greater than 260 GJ/h (250 MMBtu/h) and (2) serve a generator capable of selling more than 25 MW-net of electricity to the grid. We also are finalizing applicability requirements that will exempt from the final standards (1) all stationary combustion turbines that are dedicated non-fossil fuel-fired units (*i.e.,* combustion turbines capable of combusting 50 percent or more non-fossil fuel) and subject to a federally enforceable permit condition restricting annual fossil fuel use to 10 percent or less of a unit's annual heat input capacity; (2) the large majority of industrial CHP units (*i.e.,* CHP combustion turbines that are subject to a federally enforceable permit condition limiting annual net-electric sales to the product of the unit's net design efficiency multiplied by the unit's potential output, or 219,000 MWh, whichever is greater); (3) combustion turbines that are physically incapable of burning natural gas (*i.e.,* not connected to a natural gas pipeline); and (4) municipal waste combustors and commercial or industrial solid waste incinerators (units subject to subparts Eb or CCCC of this part).

For combustion turbines subject to an emission standard, we are finalizing three subcategories: base load natural gas-fired units, non-base load natural gas-fired units, and multi-fuel-fired units. We use the term base load natural gas-fired units to refer to stationary combustion turbines that (1) burn over 90 percent natural gas and (2) sell electricity in excess of their design efficiency (not to exceed 50 percent) multiplied by their potential electric output. To be in this subcategory, a stationary combustion turbine must exceed the ''natural gas-use criterion'' on a 12-operating-month rolling average and the ''percentage electric sales'' criterion on both a 12-operating-month and 3-year rolling average basis. We use the term non-base load natural gas-fired units to refer to stationary combustion turbines that (1) burn over 90 percent natural gas and (2) have net-electric sales equal to or below their design efficiency (not to exceed 50 percent) multiplied by their potential electric output. These criteria are calculated on the same rolling average bases as for the base load subcategory. Finally, we use the term multi-fuel-fired units to refer to stationary combustion turbines that burn 10 percent or more non-natural gas on a 12-operating-month rolling average basis. We are not finalizing the proposed emission standards for modified sources and are withdrawing those standards. We explain our rationale for these final decisions in Sections IX and XV of this preamble.

B. Best System of Emission Reduction

We are finalizing BSER determinations for the three subcategories of stationary combustion turbines referred to above: base load natural gas-fired units, non-base load natural gas-fired units, and multi-fuel-fired units. For newly constructed and reconstructed base load natural gas-fired stationary combustion turbines, the BSER is the use of efficient NGCC technology. For newly constructed and reconstructed non-base load natural gas-fired stationary combustion turbines, the BSER is the use of clean fuels (*i.e.,* natural gas with an allowance for a small amount of distillate oil). For multi-fuel-fired stationary combustion turbines, the BSER is also the use of clean fuels (*e.g.,* natural gas, ethylene, propane, naphtha, jet fuel kerosene, fuel oils No. 1 and 2, biodiesel, and landfill gas).

C. Final Emission Standards

For all newly constructed and reconstructed base load natural gas-fired combustion turbines, we are finalizing an emission standard of 1,000 lb CO_2/MWh-g, calculated on a 12-operating-month rolling average basis. We are also finalizing an optional emission standard of 1,030 lb CO_2/MWh-n, calculated on a 12-operating-month rolling average basis, for stationary combustion turbines in this subcategory. For newly constructed and reconstructed non-base load natural gas-fired combustion turbines, we are finalizing a standard of 120 lb CO_2/MMBtu, calculated on a 12-operating-month rolling average basis. For newly constructed and reconstructed multi-fuel-fired combustion turbines, we are finalizing a standard of 120 to 160 lb CO_2/MMBtu, calculated on a 12-operating-month rolling average basis. The emission standard for multi-fuel-fired combustion turbines co-firing natural gas with other fuels shall be determined at the end of each operating month based on the percentage of co-fired natural gas. Table 15 summarizes the subcategories, BSER determinations, and emission standards for combustion turbines.

TABLE 15—COMBUSTION TURBINE SUBCATEGORIES AND BSER

Subcategory	BSER	Emission standard
Base load natural gas-fired combusiton turbines	Efficient NGCC	1,000 lb CO_2/MWh-g or 1,030 lb CO_2/MWh-n
Non-base load natural gas-fired combustion turbines	Clean fuels	120 lb CO_2/MMBtu
Multi-fuel-fired combustion turbines	Clean fuels	120 to 160 lb CO_2/MMBtu [528]

D. Significant Differences Between Proposed and Final Combustion Turbine Provisions

As shown in Tables 16 and 17 below, the proposed rule included several general applicability criteria and two subcategorization criteria for combustion turbines. In addition to the proposed applicability and subcategorization framework, we solicited comment on a ''broad applicability approach'' that included most combustion turbines irrespective of the actual amount of electricity sold to the grid or the actual amount of natural gas burned (*i.e.,* non-base load units and multi-fuel-fired units, respectively). The broad applicability approach changed the proposed ''percentage electric sales'' and ''natural gas-use'' criteria to distinguish among subcategory-specific emissions standards. Specifically, in the broad applicability approach, we solicited comment on subjecting non-base load units and multi-fuel-fired units to ''no emissions standard,'' while still including them in the general applicability. We also solicited comment on establishing a separate numerical standard for non-base load units. The final rule retains all of the proposed applicability criteria in some form, but most closely tracks the broad applicability approach by finalizing the percentage electric sales and natural gas-use criteria as thresholds that distinguish among three subcategories of combustion turbines with separate emissions standards.

The final rule also includes exceptions to the broad applicability approach that we solicited comment on, with some changes that are responsive to public comments. Categorical exceptions to the broad applicability criteria are the exclusions for CHP units, non-fossil fuel units, and combustion turbines not able to combust natural gas. First, the proposed applicability criteria did not include CHP units that were constructed for the purpose of or that actually sell one-third or less of their potential electric output or 219,000 MWh, whichever is greater, to the grid. The final rule eliminates the ''constructed for the purpose of'' and actual sales aspects of the proposal and replaces them with an exemption for CHP units that take federally enforceable permit conditions restricting net-electric sales to a percentage of potential electric sales based on the unit's design efficiency or 219,000 MWh, whichever is greater. Second, the proposed applicability criteria did not include non-fossil fuel units that burn 10 percent or less fossil fuel on a 3-year rolling average. The final rule similarly replaces the actual fuel-use aspect of the proposal with an exemption for non-fossil fuel units that take federally enforceable permit conditions limiting fossil-fuel use to 10 percent or less of annual heat input capacity. Finally, the proposed applicability criteria did not include combustion turbines that burn 90 percent or less natural gas on a 3-year rolling average basis. In contrast, the final rule includes most fossil fuel-fired combustion turbines regardless of the amount of natural gas burned, with an exception for combustion turbines that are not connected to natural gas pipelines. Finally, in response to public comments, we are not finalizing the subcategories for large and small combustion turbines that were contained in the proposal. Instead, all base load natural gas-fired combustion turbines must meet an emission standard of 1,000 lb CO_2/MWh-g.

TABLE 16—PROPOSED APPLICABILITY CRITERIA VERSUS FINAL APPLICABILITY CRITERIA

Applicability Criteria	Proposed Applicability	Final Applicability
Base load rating criterion	Base load rating > 73 MW (250 MMBtu/h)	Base load rating > 260 GJ/h [529] (250 MMBtu/h)
Total electric sales criterion	Constructed for purpose of and actually selling > 219,000 MWh-n to the grid.	Ability to sell > 25 MW-n to the grid
Percentage electric sales criterion	Constructed for purpose of and having actual net-sales to the grid > one-third of potential electric output.	Changed to subcategorization criterion per broad applicability approach
Natural gas-use criterion	Actually burns > 90 percent natural gas	• Changed to subcategorization criterion per broad applicability approach • Exemption for combustion turbines that are not connected to a natural gas supply
Fossil fuel-use criterion	Actually burns > 10 percent fossil fuel	Exemption based on permit condition limiting amount of fossil fuel burned to ≤ 10 percent of annual heat input capacity
Combined Heat and Power (CHP) exemption	NA	Exemption based on permit condition limiting net-electric sales to ≤ design efficiency multiplied by potential electric output, or 219,000 MWh-n, whichever is greater
Non-EGU exemption	Exemption for municipal solid waste combustors and commercial or industrial solid waste incinerators.	Same as proposal

[528] The emission standard for combustion turbines co-firing natural gas with other fuels shall be determined based on the amount of co-fired natural gas at the end of each operating month.

TABLE 17—PROPOSED SUBCATEGORIES VERSUS FINAL SUBCATEGORIES

Subcategory	Proposed Criteria	Final Criteria
Small combustion turbine subcategory	Base load rating ≤ 850 MMBtu/h	NA
Large combustion turbine subcategory	Base load rating > 850 MMBtu/h	NA
Base load natural gas-fired base load combustion turbine subcategory.	NA	• Actually burns > 90 percent natural gas • Net-electric sales > design efficiency (not to exceed 50 percent) multiplied by potential electric output
Non-base load natural gas-fired combustion turbine subcategory.	NA	• Actually burns > 90 percent natural gas • Net-electric sales ≤ design efficiency (not to exceed 50 percent) multiplied by potential electric output
Multi-fuel-fired combustion turbine subcategory	NA	Actually burns ≤ 90 percent natural gas

IX. Rationale for Final Standards for Newly Constructed and Reconstructed Stationary Combustion Turbines

This section discusses the EPA's rationale for the final applicability criteria, BSER determinations, and standards of performance for newly constructed and reconstructed stationary combustion turbines. In this section, we present a summary of what we proposed, a selection of the significant comments we received, and our rationale for the final determinations, including how the comments influenced our decision-making.

A. Applicability

This section describes the proposed applicability criteria, applicability issues we specifically solicited comment on, the relevant significant comments, and the final applicability criteria. We also provide our rationale for finalizing applicability criteria based strictly on design and permit restrictions rather than actual operating characteristics. Finally, we explain why the proposed percentage electric sales and natural gas-use applicability criteria are being finalized instead as criteria to distinguish between separate subcategories of stationary combustion turbines.

1. Proposed Applicability Criteria

In the January 2014 proposal, we proposed several applicability criteria for stationary combustion turbines. Specifically, to be subject to the proposed emission standards, we proposed that a unit must (1) be capable of combusting more than 73 MW (250 MMBtu/h) heat input of fossil fuel; (2) be constructed for the purpose of supplying and actually supply more than one-third of its potential electric output capacity to a utility power distribution system for sale (that is, to the grid) on a 3-year rolling average; (3) be constructed for the purpose of supplying and actually supply more than 219,000 MWh net-electric output to the grid on a 3-year rolling average; (4) combust over 10 percent fossil fuel on a 3-year rolling average; and (5) combust over 90 percent natural gas on a 3-year rolling average. We proposed exempting municipal solid waste combustors and commercial and industrial solid waste incinerators.

Under these proposed applicability criteria, two types of stationary combustion turbines that are currently subject to criteria pollutant standards under subpart KKKK would not have been subject to CO_2 standards. The first type was stationary combustion turbines that are constructed for the purpose of selling and that actually sell one-third or less of their potential output or 219,000 MWh or less to the grid on a 3-year rolling average basis (*i.e.,* non-base load units). The second type was combustion turbines that actually combust 90 percent or less natural gas on a 3-year rolling average basis (*i.e.,* multi-fuel-fired units).

We proposed the electric sales criteria in part because they already exist in other regulatory contexts (*e.g.,* the coal-fired EGU criteria pollutant NSPS) and would promote consistency between regulations. Our understanding at proposal was that the percentage electric sales criterion would distinguish between non-base load units (*e.g.,* low capital cost, flexible, but relatively inefficient simple cycle units) and base load units (*i.e.,* higher capital cost, less flexible, but relatively efficient combined cycle units).

While the proposed applicability criteria did not explicitly exempt simple cycle combustion turbines from the emission standards, we concluded that, as a practical matter, the vast majority of simple cycle turbines would be excluded because they historically have operated as peaking units and, on average, have sold less than five percent of their potential electric output on an annual basis, well below the proposed one-third electric sales threshold.

a. Solicitation of comment on applicability, generally

We solicited comment on a range of issues related to applicability. In conjunction with the proposed one-third (*i.e.,* 33.3 percent) electric sales threshold, we solicited comment on a threshold between 20 to 40 percent of potential electric output. We also solicited comment on a variable percentage electric sales criterion, which would allow more efficient, lower emitting turbines to run for longer periods of operation before becoming subject to the standards of performance. Under this ''sliding scale'' approach, the percentage electric sales criterion would be based on the net design efficiency of the combustion turbine being installed. In this way, more efficient combustion turbines would be able to sell a greater portion of their potential electric output compared with less efficient combustion turbines before becoming subject to an emission standard. This approach had the benefit of incentivizing the development and installation of more efficient simple cycle combustion turbines to serve peak load.

We also solicited comment on whether the percentage electric sales criterion for stationary combustion turbines should be defined on a single calendar year basis. In addition, we solicited comment on eliminating the 219,000 MWh aspect of the total electric sales criterion to eliminate any incentive for generators to install multiple, small, less-efficient stationary combustion turbines that would be exempt due to their lower output. We further solicited comment on whether to provide an explicit exemption for all simple cycle combustion turbines regardless of the amount of electricity sold. We additionally solicited comment on how to implement the proposed electric sales, fossil fuel-use, and natural

[529] 73 MW is equivalent to 260 GJ/h. We changed units to avoid potential confusion of MW referring to electric output rather than heat input.

gas-use criteria given that they were to be evaluated as 3-year rolling averages during the first three years of operation, and we requested comment on appropriate monitoring, recordkeeping, and reporting requirements. We specifically solicited comment on whether these proposed requirements raised implementation issues because they were based on source operation after construction has occurred.

We also solicited comment on excluding electricity sold during system emergencies from the calculation of percentage electric sales. The rationale for this exclusion was that simple cycle combustion turbines intended only for peaking applications might be required to operate above the proposed percentage electric sales threshold if a major power plant or transmission line became unexpectedly unavailable for an extended period of time. The EPA proposed that this flexibility would be appropriate if the unit were called upon to run after all other available generating assets were already running at full load.

b. Solicitation of comment on broad applicability approach

In both the January 2014 proposal for newly constructed EGUs and the June 2014 proposal for modified and reconstructed EGUs, the EPA solicited comment on finalizing a broad applicability approach instead of the proposed approach. Under the proposed approach, a stationary combustion turbine could be an affected EGU one year, but not the next, depending on the unit's actual electric sales and the composition of fuel burned. The broad applicability approach is consistent with historical NSPS applicability approaches that are based on design criteria and include different emission standards for subcategories that are distinguished by operating characteristics. Specifically, we solicited comment on whether we should completely remove the electric sales and natural gas-use criteria from the general applicability framework. Instead, the percentage electric sales and natural gas-use thresholds would serve as subcategorization criteria for distinguishing among classes of EGUs and subcategory-specific emissions standards. Under this broad applicability approach, the ''constructed for the purpose of'' component of the percentage electric sales criterion would be completely eliminated so that applicability for combustion turbines would be determined only by a unit's base load rating (*i.e.,* greater than 260 GJ/h (250 MMBtu/h)) and its capability to sell power to a utility distribution system (*i.e.,* serving a generator capable of selling more than 25 MW). In contrast to the proposed applicability criteria, under the broad applicability approach, non-base load (*e.g.,* simple cycle) and multi-fuel-fired (*e.g.,* oil-fired) combustion turbines would remain subject to the rule regardless of their electric sales or fuel use. We solicited comment on all aspects of this ''broad applicability approach,'' including the extent to which it would achieve our policy objective of assuring that owners and operators install NGCC combustion turbines if they plan to sell more than the specified electric sales threshold to the grid.

2. Comments on Applicability

This section summarizes the comments we received specific to each of the proposed applicability criteria. We also received more general comments on the scope of the proposed framework as compared to the scope of the broad applicability approach. Comments on applicability for dedicated non-fossil and CHP units are discussed in Section III.

a. Base load rating criterion

Many commenters supported a base load rating of 260 GJ/h (250 MMBtu/h) because it is generally consistent with the threshold used in states participating in the Regional Greenhouse Gas Initiative (RGGI) and under Title IV programs. Other commenters opposed the proposed applicability thresholds and stated that all new, modified, and reconstructed units that sell electricity to the grid, including small EGUs and simple cycle combustion turbines, should be affected EGUs because they would otherwise have a competitive advantage in energy markets as they would not be required to internalize the costs of compliance.

b. Total electric sales criterion

Commenters noted that the 219,000 MWh total electric sales threshold put larger combustion turbines at a competitive disadvantage by distorting the market and could have the perverse impact of increasing CO_2 emissions. These commenters noted that the 219,000 MWh total electric sales threshold would allow combustion turbines smaller than approximately 80 MW to sell more than one-third of their potential electric output, but larger, more efficient combustion turbines would still be restricted to selling one-third of their potential electric output to avoid triggering the NSPS. They argued that this would result in a regulatory incentive for generators to install multiple, less-efficient combustion turbines instead of fewer, more-efficient combustion turbines and could have the unintended consequence of increasing CO_2 emissions.

c. Percentage electric sales criterion

Commenters from the power sector generally supported a complete exemption for simple cycle turbines. These commenters stated that simple cycle turbines are uniquely capable of achieving the ramp rates (the rate at which a power plant can increase or decrease output) necessary to respond to emergency conditions and hourly variations in output from intermittent renewables. Commenters noted that simple cycle combustion turbines serve a different purpose than NGCC power blocks. In addition, commenters noted that electricity generation dispatch is based on the incremental cost to generate electricity and that because NGCC units have a lower incremental generation cost than simple cycle units, economics will drive the use of NGCC technologies over simple cycle units. However, commenters also stated that historic simple cycle operating data may not be representative of future system requirements as coal units retire, generation from intermittent renewable generation increases, and numerous market and regulatory drivers impact plant operations. In the absence of a complete exemption, these commenters supported a percentage electric sales threshold between 40 to 60 percent of a unit's potential electric output.

Some commenters said that because the proposed percentage electric sales criterion applied over a three-year period, it would adversely affect grid reliability because operators conservatively would hedge short-term operating decisions to ensure that they have sufficient capacity to respond to unexpected scenarios during future compliance periods when the demand for electricity is higher. These commenters were concerned that such compliance decisions would drive up the cost of electricity as the most efficient new units are taken out of service to avoid triggering the NSPS and older, less efficient units with no capacity factor limitations are ramped up instead.

Some commenters supported the sliding-scale approach (*i.e.,* a percentage electric sales threshold based on the design efficiency of the combustion turbine) and stated that incentives for manufacturers to develop (and end users to purchase) higher efficiency combustion turbines could help mitigate concerns about a monolithic national constraint on simple cycle capacity factors.

In contrast, others commented that fast-start NGCC units intended for peaking and intermediate load applications can achieve comparable ramp rates to simple cycle combustion turbines, but with lower CO_2 emission rates. These commenters said that simple cycle turbines should be restricted to their historical role as true peaking units and that the proposed one-third electric sales threshold provided sufficient flexibility. Some commenters suggested that the one-third electric sales threshold could be reduced to 20 percent or lower without adverse impacts on grid reliability.

Commenters noted that a complete exclusion for simple cycle turbines would create a regulatory incentive for generators to install and operate less efficient unaffected units instead of more efficient affected units, thereby increasing CO_2 emissions. According to these commenters, any applicability distinctions should be based on utilization and function rather than purpose or technology.

Commenters in general supported the use of 3-year rolling averages instead of a single-year average for the percentage and total electric sales criteria because, in their view, the 3-year rolling averages would provide a better overall picture of normal operations. Some commenters stated that a rolling 12-month or calendar-year average could be severely skewed in a given year because of unforeseen or unpredicted events. They said that using a 3-year averaging methodology would provide system operators with needed flexibility to dispatch simple cycle units at higher than normal capacity factors. In contrast, some commenters stated that, because capacity is forward-looking (*e.g.,* payments for capacity are often made several years in advance), the 3-year averaging period provides limited benefit because owner/operators need to reserve the ability to respond to unforeseen events.

Commenters noted that potential compliance issues could result from the inconsistent time frame between the 3-calendar-year applicability period and the 12-operating-month compliance period. For example, a facility could sell more than one-third of its potential electric output over a 3-year period, but sell less than one-third of its potential electric output during any given 12-operating-month compliance period within that 3-year period. During a 12-operating-month period with electric sales of less than one-third of potential electric output, a unit could be operating for long periods at part load and have multiple starts and stops. These operating conditions have the potential to increase CO_2 emissions, regardless of the deign efficiency of the turbine. Therefore, a unit could have an emission rate in excess of the proposed standard.

Regarding the relationship between the percentage electric sales criterion and system emergencies, multiple commenters supported exclusion of electricity generated as a result of a system emergency from counting towards net sales. These commenters stated that the exclusion was appropriate because the benefits of operating these units to generate electrical power during emergency conditions would outweigh any adverse impacts from short-term increases in CO_2 emissions. One commenter stated that, in addition to declared grid emergencies, other circumstances might warrant emergency exemption under the rule, including extreme market conditions, limitations on fuel supply, and reliability responses.

Multiple commenters opposed the exclusion of system emergencies when calculating a source's percentage electric sales for applicability purposes because NSPS must apply continuously, even during system emergencies. These commenters stated that the EPA does not have the authority under the CAA to suspend the applicability of a standard during periods of system emergency. Some commenters stated that an exclusion would be unnecessary because the EPA Assistant Administrator for Enforcement has the authority to advise a source that the government will not sue the source for taking certain actions during an emergency. Commenters said that this enforcement discretion approach has provided prompt, flexible relief that is tailored to the needs of the particular emergency and the communities being served and is only utilized where the relief will address the particular emergency at hand.

Commenters added that this enforcement discretion approach is consistent with the CAA's mandate that emission limits apply continuously and provide safeguards against abuse. One commenter stated that emergencies happen rarely and typically last for short periods, that the proposed percentage electric sales threshold would allow a source to operate at its full rated capacity for up to 2,920 hours per year without triggering applicability, and that the potential occurrence of grid emergencies would represent a tiny fraction of this time. Another commenter stated that no emergency short of large scale destruction of power generating capacity by terrorism, war, accident, or natural disaster could justify operating a peaking unit above a 10-percent capacity factor on a 3-year rolling average.

d. Broad applicability approach

In response to the EPA's request for comments on whether the proposed applicability requirements that retrospectively look back at actual events (*i.e.,* the electric sales and fuel use criteria) would create implementation issues, several permitting authorities opposed the provisions because units could be subject to coverage one year but not the next, resulting in compliance issues and difficulties in determining proper pre-construction and operating permit conditions. These permitting authorities suggested that in order for a source to avoid applicability, the source should be subject to a federally enforceable permit condition with associated monitoring, recordkeeping, and reporting conditions for assessing applicability on an ongoing basis. Other commenters stated that an applicability test that concludes after construction and operation have commenced is inconsistent with the general purpose of an applicability test—to provide clear and predictable standards of performance for new sources that would apply when they begin operations.

Some commenters opposed the proposed retrospective applicability criteria related to actual output supplied during a preceding compliance period because EGUs must know what performance standards will apply to them during the licensing process, and such criteria do not allow the permitting authority and the public to know in advance whether an emission standard applies to a proposed new unit. Other commenters said that EGUs undergoing permitting should be allowed to request limits in their operating permit conditions in order to remain below the applicability thresholds, as this methodology is consistent with the pre-construction permitting requirements in many federally approved SIPs and the current approach under the Title V permitting program.

Many commenters stated a preference for the ''proposed applicability approach'' over the ''broad applicability approach.'' These commenters did not think it was necessary to require non-base load or multi-fuel-fired combustion turbines to be subject to emission standards. They stated that there is no justification for imposing burdensome monitoring, reporting, and recordkeeping requirements that would have no environmental benefit (*i.e.,* would not reduce CO_2 emissions) because these units would be subject to ''no emissions standards.'' Other commenters supported the broad applicability approach and stated that all new, modified, and reconstructed units that sell electricity to the grid, including small EGUs, oil-fired combustion turbines, and simple cycle combustion turbines should be affected EGUs because they would otherwise have a competitive advantage in energy markets as they would not be required to internalize the costs of compliance.

In contrast, to preserve the discretion of state planners under section 111(d), many other commenters supported the broad applicability approach and the inclusion of new simple cycle units within the scope of the section 111(b) emission standards so that similar, existing simple cycle units could be subject to the 111(d) standards. Numerous other commenters stated that all units that sell electricity to the grid should be subject to a standard, including simple cycle units, because they view the utility grid as a single integrated system and that doing so may simplify development of future frameworks for cost-effective carbon reductions from existing units, such as frameworks based on system-wide approaches.

3. Final Applicability Criteria and Rationale

Based on our consideration of the comments received related to the proposed applicability criteria and practical implementation issues, we are revising how those criteria will be implemented. The final applicability criteria for combustion turbines are generally consistent with the broad applicability approach on which we solicited comment. Section VIII of this preamble presents each proposed applicability criterion together with the form of the criterion in the final rule. The final general applicability framework includes the proposed criteria based on the combustion turbine's base load rating and the combustion turbine's total electric sales capacity. The final general applicability framework also includes multiple exemptions that are relevant to combustion turbines: combustion turbines that are not connected to natural gas pipelines; CHP facilities with federally enforceable limits on total electric sales; dedicated non-fossil units with federally enforceable limits on the use of fossil fuels; and municipal waste combustors and incineration units.

The final applicability framework reflects multiple variations from the proposal that are responsive to public comments. First, consistent with the broad applicability approach, we are finalizing the percentage electric sales and natural gas-use thresholds as subcategorization criteria instead of as applicability criteria. In addition, for non-CHP combustion turbines, we are eliminating the proposed 219,000 MWh total electric sales criterion. Finally, we are eliminating the proposed ''constructed for the purpose of'' qualifier for the total and percentage electric sales criteria. We are also not finalizing CO_2 standards for dedicated non-fossil fuel-fired or industrial CHP combustion turbines. The rationale for not finalizing CO_2 standards for dedicated non-fossil and industrial CHP units is discussed in more detail in Section III.

The EPA agrees with commenters that the NSPS applicability framework should be structured so that permitting authorities, the regulated community, and the public can determine what standards apply prior to a unit having commenced construction. With this in mind, the EPA has concluded that the proposed fossil fuel-use, natural gas-use, percentage electric sales, and total electric sales applicability criteria for combustion turbines are not ideal approaches. Because applicability determinations based on these criteria could change from year to year (*i.e.,* units could move in and out of coverage each year depending on actual operating parameters), some operators would not know the extent of their compliance obligations until after the compliance period.

Further, from a practical implementation standpoint, existing permitting rules generally require pre-construction permitting authorities to include enforceable conditions limiting operations such that unaffected units will not trigger applicability thresholds. Such conditions are often called ''avoidance'' or ''synthetic minor'' conditions, and these conditions typically include ongoing monitoring, recordkeeping, and reporting requirements to ensure that operations remain below a particular regulatory threshold.

The following sections provide further discussion of the final general applicability criteria and the rationale for changing certain proposed applicability criteria to subcategorization criteria.

a. Base load rating criterion

We are retaining the applicability criterion that a combustion turbine must be capable of combusting more than 260 GJ/h (250 MMBtu/h) heat input of fossil fuel. We revised the proposed 73 MW form of the base load rating criterion to 260 GJ/h because some commenters misinterpreted the 73 MW form (which is mathematically equivalent to 250 MMBtu/h) as the electrical output rating of the generator. This change is a non-substantive unit conversion intended to limit misinterpretation. While some commenters suggested that we expand this applicability criterion to cover smaller EGUs as well, we did not propose to cover smaller units. Because smaller units emit relatively few CO_2 emissions compared to larger units and because we currently do not have enough information to identify an appropriate BSER for these units, we are not finalizing CO_2 standards for smaller units.

b. Total electric sales criterion

The proposed 219,000 MWh total sales criterion was based on a 25 MW unit operating at base load the entire year (*i.e.,* 25 MW * 8,760 h/y = 219,000 MWh/y). This criterion was included in the original subpart Da coal-fired EGU criteria pollutant NSPS. Coal-fired EGUs tend to be much larger than 25 MW, and the criterion's primary purpose was to exempt industrial CHP facilities from the criteria pollutant NSPS. In the context of combustion turbines, however, commenters expressed concerns that the 219,000 MWh electric sales threshold would actually encourage owners and operators to install multiple, smaller, less-efficient simple cycle combustion turbines instead of a single, larger, more-efficient simple cycle turbine. The reason for this is that the 219,000 MWh threshold would allow smaller simple cycle combustion turbines of less than 80 MW to sell significantly more electricity relative to their potential electric output than larger turbines. Many commenters also indicated that having the flexibility to operate a simple cycle turbine at a higher capacity factor is important because it allows for capacity payments from the transmission authority. In light of these comments, we are not finalizing the 219,000 MWh total electric sales criterion for non-CHP combustion turbines. Instead, we are finalizing a criterion that will exempt combustion turbines that do not have the ability to sell at least 25 MW to the grid. This approach will maintain our goal of exempting smaller EGUs, while avoiding the perverse environmental incentives mentioned by the commenters. As explained in Section III, however, industrial CHP units are sized based on demand for useful thermal output, so there is less of an incentive for owners and operators to install multiple smaller units. Therefore, we are maintaining the 219,000 MWh total electric sales criterion for CHP units.

c. Percentage electric sales criterion

Commenters generally opposed the proposed percentage electric sales criterion approach because it was based in part on actual electric sales, meaning applicability could change periodically (*i.e.,* a unit's electric sales may change over time, rising above and falling below the electric sales threshold). The EPA agrees this situation is not ideal. To avoid situations in which applicability changes from year to year, we first considered two approaches using permit restrictions. Under the first approach, a standard would apply to all sources with permit restrictions mandating electric sales above a threshold (*i.e.,* an approach that closely mirrors the proposed percentage electric sales criterion). Under the second approach, a standard would apply to all sources without permit restrictions limiting electric sales to a level below that threshold (*i.e.,* effectively identifying non-base load units and excluding them from applicability). As stated in the proposal, we did not think it was critical to include peaking and cycling units because peaking turbines operate less and because it would be much more expensive to lower their emission profile to that of a combined cycle power plant or a coal-fired plant with CCS.

The first approach is not practical, however, because new combustion turbines could avoid applicability by simply not having a permit restriction at all. Moreover, even if a combustion turbine were subject to the restriction, it could violate its permit if it did not operate enough to sell the requisite amount of electricity. This would be nonsensical, especially because system demand would not always be sufficient to allow all permitted units to operate above the threshold. Therefore, we rejected the first permitting approach.

In contrast, the second approach would be a viable method for identifying and exempting peaking units from applicability. However, there are multiple drawbacks to such an applicability approach. First, this approach would subject those turbines without a permit restricting electric sales to the final emission standards, which raises concerns as to whether turbines with lower actual sales could achieve the standards. For example, new NGCC units tend to dispatch prior to older existing units and will generally operate for extended periods of time near full load and sell electricity above the percentage electric sales threshold. However, as NGCC units age, they tend to start and stop more frequently and operate at part load. Yet, even if these units sell below the percentage electric sales threshold, they would still be affected units if they did not take a permit restriction. As commenters noted, part-load operation and frequent starts and stops can reduce the efficiency of a combustion turbine. While we are confident that our final standards for base load natural gas-fired combustion turbines can be achieved by units serving either base or intermediate load, we are not as confident that affected NGCC units that might someday be operated as non-base load units (*e.g.,* as NSPS units age, their incremental generating costs will tend to be higher than newer units and they will dispatch less) could achieve the standards.

More importantly, however, we are concerned that using a permitting approach for the percentage electric sales criterion would create problems due to the interaction between 111(b) and 111(d). Under the second permitting approach we considered, units with low electric sales would be excluded from applicability, while units with high electric sales would be included. While these low-electric sales units would generally be simple cycle combustion turbines and the high-electric sales units would generally be NGCC combustion turbines, this would not always be the case. In contrast, we are finalizing an applicability approach in the 111(d) emission guidelines that is based on a combustion turbine's design characteristics rather than electric sales. Simple cycle combustion turbines are excluded from applicability, while NGCC units are included. As a result, the universe of sources covered by the 111(b) standards would not necessarily be the same universe of sources covered by the 111(d) standards.

To resolve this issue, we considered whether we could change the 111(d) applicability criteria to be based on historical operation rather than design characteristics. For example, if an existing combustion turbine had historically sold less than one-third of its potential output to the grid, then it would be exempt from the emission guidelines. However, many existing NGCC units have historically sold less than this amount of electricity, meaning that they would not be subject to the rule. We ran into similar issues when considering other thresholds. For example, a percentage electric sales threshold of 10 percent would still exempt roughly 5 percent of existing NGCC units from 111(d), while simultaneously raising achievability concerns with the 111(b) standard. Moreover, even if we had finalized 111(d) applicability criteria based on historical operations, existing NGCC units could have decided to take a permit restriction limiting their electric sales going forward to avoid applicability. Under any of these scenarios, our goals with respect to 111(d) would not be accomplished.

To avoid this result, the EPA has concluded that it is appropriate to finalize the broad applicability approach and set standards for combustion turbines regardless of what percentage of their potential electric output they sell to the grid. To accommodate the continued use of simple cycle and fast-start NGCC combustion turbines for peaking and cycling applications, however, the EPA has subcategorized natural gas-fired combustion turbines based on a variation of the proposed percentage electric sales criterion. Specifically, and as explained in more detail in Section IX.B.2, we are finalizing the sliding-scale approach on which we solicited comment.

d. Natural gas-use criterion

Similar to the proposed electric sales criteria, commenters generally opposed the proposed natural gas-use criterion being based on actual operating parameters. As with the electric sales criteria, the EPA agrees that applicability that can switch periodically due to operating parameters is not ideal. The EPA evaluated two approaches for implementing the intent of the proposed natural gas-use criterion (*i.e.,* to exclude non-natural gas-fired combustion turbines) through operating permit restrictions. Under the first approach, an emission standard would apply to all combustion turbines with a permit restriction mandating that natural gas contribute over 90 percent of total heat input.[530] Under the second approach, an emission standard would apply to all combustion turbines without a permit restriction limiting natural gas use to 90 percent or less of total heat input.[531] As with the percentage electric sales criterion, the first approach is not practical because combustion turbines could avoid

[530] This approach could also be written as ''an emission standard would apply to all combustion turbines with a permit restriction limiting the use of non-natural gas fuels to 10 percent or less of the total heat input.'' Applicability could then be avoided by simply being permitted to burn non-natural gas fuels for more than 876 hours per year even if they actually intended to seldom, if ever, combust the alternate fuels.

[531] This approach could also be written as ''an emission standard would apply to all combustion turbines without permit restrictions mandating that non-natural gas use contribute over 10 percent or more of total heat input.''

applicability by simply not having a permit that requires the use of more than 90 percent natural gas, even if they intend to only burn natural gas. We disregarded this approach because it would essentially provide a pathway for all NGCC units to avoid applicability under both 111(b) and 111(d). The second approach is problematic because operating permit restrictions to improve air quality are typically written to limit high emission activities (*e.g.,* limiting the use of distillate oil to 500 hours annually), not to limit lower emitting activities. This approach could lead to perverse environmental impacts by incentivizing the use of non-natural gas fuels, which would typically result in higher CO_2 emissions. Furthermore, the second approach would not limit the fuels that can be burned by affected units (*i.e.,* combustion turbines not required to use non-natural gas fuels) and would continue to cover combustion turbines even when they burn over 10 percent non–natural gas fuels. Because all non-natural gas fuels except H_2 have CO_2 emission rates higher than natural gas, this approach would exacerbate the concerns raised by commenters about the achievability of the 111(b) requirements when burning back up fuels.

In light of these issues, the EPA has concluded that permit restrictions are not an ideal approach to distinguishing between natural gas-fired and multi-fuel-fired combustion turbines and are finalizing a variation of the broad applicability approach. The EPA has concluded that the only practical approach to implement the natural gas-use criterion is to look at the turbine's physical ability to burn natural gas. Therefore, we are not finalizing CO_2 standards for combustion turbines that are not capable of firing any natural gas (*i.e.,* not connected to a natural gas pipeline). From a practical standpoint, the burners of most combustion turbines can be modified to burn natural gas, so this exemption is essentially limited to combustion turbines that are built in remote or offshore locations without access to natural gas. Consistent with the broad applicability approach, we are finalizing standards for all other combustion turbines, but are subcategorizing between natural gas-fired turbines and multi-fuel-fired turbines. Specifically, and as explained in more detail in Section IX.B.3, we are distinguishing between these classes of turbines based on whether they burn greater than 90 percent natural gas or not.

B. Subcategories

We are finalizing a variation of the broad applicability approach for combustion turbines where the percentage electric sales and natural gas-use criteria serve as thresholds that distinguish between three subcategories. These subcategories are base load natural gas-fired units, non-base load natural gas-fired units, and multi-fuel-fired units. Under the final subcategorization approach, multi-fuel-fired combustion turbines are distinguished from natural gas-fired turbines if fuels other than natural gas (*e.g.,* distillate oil) supply 10 percent or more of heat input. Natural gas-fired turbines are further subcategorized as base load or non-base load units based on the percentage electric sales criterion. The percentage electric sales threshold that distinguishes base load and non-base load units is based on the specific turbine's design efficiency (*i.e.,* the sliding-scale approach). The percentage electric sales threshold is capped at 50 percent.

This section describes comments we received regarding the proposed size-based subcategories and our rationale for not finalizing them. In addition, it describes comments we received regarding sales-based subcategories and our rationale for adopting the sliding scale to distinguish between subcategories. Finally, it describes comments we received regarding fuel-based subcategories and our rationale for adopting fuel-based subcategories.

1. Size-Based Subcategories

At proposal, the EPA identified two size-based subcategories: (1) large natural gas-fired stationary combustion turbines with a base load rating greater than 850 MMBtu/h and (2) small natural gas-fired stationary combustion turbines with a base load rating of 850 MMBtu/h or less. The EPA received numerous comments regarding our proposal to subcategorize combustion turbines by size. Some commenters agreed with the 850 MMBtu/h cut-point between large and small units, some suggested increasing it to 1,500 MMBtu/h, and others suggested eliminating size-based subcategorization altogether. For example, some commenters stated that the 850 MMBtu/h cut-point was inappropriate because it was originally calculated based on NO_X performance, not CO_2 performance. These commenters stated that 850 MMBtu/h was not a logical demarcation between more efficient and less efficient combustion turbines, but rather would divide the units into arbitrary size classifications. These commenters suggested that 1,500 MMBtu/h would be a better cut-point because data reported to *Gas Turbine World* (GTW) showed that new combustion turbines are not currently offered with a heat input rating between 1,300 MMBtu/h and 1,800 MMBtu/h, so the higher cut-point would more accurately reflect when more efficient technologies are available.

In contrast, other commenters said that differentiation between small and large combustion turbines was not justified at all because many of the same efficiency technologies that reduce the emission rates of larger units could be incorporated into smaller units (*e.g.,* upgrades that increase the turbine engine operating temperature, increase the turbine engine pressure ratio, or add multi-pressure steam and a steam reheat cycle). These commenters also said that separate standards for small and large turbines would undermine the incentive for technology innovation, which they described as a key purpose of the NSPS program, and that relaxing standards for smaller units would discourage investment in more efficient technologies, resulting in increased CO_2 emissions. These commenters recommended that the limit for both large and small units be no higher than 1,000 lb CO_2/MWh-g.

After evaluating these comments, the EPA has decided not to subcategorize combustion turbines based on size for several reasons. First, the heat input values listed in *Gas Turbine World* do not include potential heat input from duct burners.[532] Because the heat input from duct burners is necessary to accurately determine potential electric output, our definition of ''base load rating'' includes the heat input from any installed duct burners. The EPA reviewed the heat input data for existing NGCC units that has been submitted to CAMD. These data include the heat input from duct burners and show that multiple NGCC power blocks have been built in the past with heat input capacities that fall within the range that commenters suggested new turbines are not offered. Therefore, the EPA has concluded that the regulated community uses various sizes of NGCC turbines and when the heat input from duct burners is included, there is no clear break between the NGCC unit sizes that could distinguish between small and large units. In fact, subcategorizing

[532] Duct burners are optional supplemental burners located in the HRSG that are used to generate additional steam. Heat input to duct burners could in theory be twice that of the combustion turbine engine, but are more commonly sized at 10 to 30 percent of the heat input to the combustion turbine engine.

by size could unduly influence the development of future NGCC offerings because manufacturers could be incentivized to design new products at the top end of the small subcategory to take advantage of the less stringent emission standard.

Second, commenters suggested that a cut-point of 1,500 MMBtu/h reflects when more efficient technologies become available. However, when we reviewed actual operating data and design data, we only found a relatively weak correlation between turbine size and CO_2 emission rates and did not see a dramatic drop in CO_2 emission rates at 1,500 MMBtu/h. The variability of emission rates among similar size units far exceeds any difference that could be attributed to a difference in size. In addition, the most efficient one-to-one configuration NGCC power block with a base load rating of 1,500 MMBtu/h or less has a design emission rate of the 767 lb CO_2/MWh-n (984 MMBtu/h). The most efficient one-to-one configuration NGCC power block with a base load rating just greater than 1,500 MMBtu/h has a design emission rate of 772 lb CO_2/MWh-n (1,825 MMBtu/h). Because the smaller unit has a lower design emission rate than the larger unit, increasing the cut-point does not make sense.

Finally, the EPA has concluded that, while certain smaller NGCC designs may be less efficient than larger NGCC designs, most existing small units have demonstrated emission rates below the range of emission rates on which we solicited comment. We have concluded that the lower design efficiencies of some small NGCC units are primarily related to model-specific design choices in both the turbine engine and HRSG, not an inherent limitation in the ability of small NGCC units to have comparable efficiencies to large NGCC units. Specifically, manufacturers could improve the efficiency of the turbine engine by using turbine engines with higher firing temperatures and high compression ratios and could improve the efficiency of the steam cycle by switching from single or double-pressure steam to triple-pressure steam and adding a reheat cycle. For all of these reasons, we have decided against subcategorizing combustion turbines based on size. Our rationale for setting a single standard for small and large combustion turbines is explained in more detail in Section IX.D.3.a below.

2. Sales-Based Subcategories

As described above in Section IX.A.3.c, the final applicability criteria do not include an exemption for non-CHP units based on actual electric sales or permit restrictions limiting the amount of electricity that can be sold. Instead, we are finalizing the percentage electric sales criterion as a threshold to distinguish between two natural gas-fired combustion turbine subcategories. The industry uses a number of terms to describe combustion turbines with different operating characteristics based on electric sales (*e.g.,* capacity factors). Combustion turbines that operate at near-steady, high loads are generally referred to as ''base load'' or ''intermediate load'' units, depending on how many hours the units operate annually. Combustion turbines that operate continuously with variable loads that correspond to variable demand are referred to as ''load following'' or ''cycling'' units. Combustion turbines that only operate during periods with the highest electricity demand are referred to as ''peaking'' units. However, it is difficult to characterize a particular unit using just one of these terms. For example, a particular unit may serve as a load following unit during winter, but serve as a base load unit during summer. In addition, none of these terms has a precise universal definition. In this preamble, we refer to the subcategory of combustion turbines that sell a significant portion of their potential electric output as ''base load units.'' This subcategory includes units that would colloquially be referred to as base load units, as well as some intermediate load and load following units. We refer to all other units as ''non-base load units.'' This subcategory includes peaking units, as well as some load following and intermediate load units. The threshold that distinguishes between these two subcategories is determined by a unit's design efficiency and varies from 33 to 50 percent, hence the term ''slide scale'' approach.

Numerous commenters supported three sales-based subcategories for peaking, intermediate load, and base load units. These commenters said that each subcategory should be distinguished by annual hours of operation and that each should have a different BSER and emission standard. Other commenters opposed the tiered approach. These commenters said that separate standards for different operating conditions would be complicated to implement and enforce, while providing few benefits. These commenters said that a tiered approach could also have the unintended consequence of encouraging less efficient technologies because it would create a regulatory incentive to install lower-capital-cost, less-efficient units that would operate under the percentage electric sales threshold instead of higher-capital-cost, more-efficient units that would operate above the threshold.

After evaluating these comments, the EPA has concluded that it is appropriate to adopt a two-tiered subcategorization approach based on a percentage electric sales threshold to distinguish between non-base load and base load units. While we agree with commenters that separate standards for peaking, intermediate, and base load units is attractive on the surface, we ultimately concluded that a three-tiered approach is not appropriate for several reasons. First, the increased generation from renewable sources that is anticipated in the coming years makes it very difficult to determine appropriate thresholds to distinguish among peaking, intermediate, and base load subcategories. Indeed, the boundaries between these demand-serving functions may blur or shift in the years to come. The task is further complicated because each transmission region has a different mix of generation technologies and load profiles with different peaking, intermediate, and base load requirements.

Second, there are only two distinct combustion turbine technologies—simple cycle units and NGCC units. In theory, the BSER for the intermediate load subcategory could be based on high-efficiency simple cycle units or fast-start NGCC units, but these are variations on traditional technologies and not necessarily distinct. Moreover, we do not have specific cost information on either high-efficiency simple cycle turbines or fast-start NGCC units, so our ability to make cost comparisons to conventional designs is limited.

Finally, even if we could identify appropriate sales thresholds to distinguish between peaking, intermediate load, and base load subcategories, we do not have sufficient information to establish a meaningful output-based standard for an intermediate load subcategory at this time. In the transition zone from peaking to base load operation (*i.e.,* cycling and intermediate load), combustion turbines may have similar electric sales, but very different operating characteristics. For example, despite having similar sales, one unit might have relatively steady operation for a short period of time, while another could have variable operation throughout the entire year. The latter unit would likely have a higher CO_2 emission rate. For all of these reasons, the EPA has concluded that we do not have sufficient information at this time to establish three sales-based subcategories.

Instead, as we explained above, we are finalizing two sales-based subcategories. To determine an appropriate threshold to distinguish between base load and non-base load units, the EPA considered the important characteristics of the combustion turbines that serve each type of demand. For non-base load units, low capital costs and the ability to start, stop, and change load quickly are key. Simple cycle combustion turbines meet these criteria and thus serve the bulk of peak demand. In contrast, for base load units, efficiency is the key consideration, while capital costs and the ability to start and stop quickly are less important. While NGCC units have relatively high capital costs and are less flexible operationally, they are more efficient than simple cycle units. NGCC units recover the exhaust heat from the combustion turbine with a HRSG to power a steam turbine, which reduces fuel use and CO_2 emissions by approximately one-third compared to a simple cycle design. Consequently, base load units use NGCC technology. Because simple cycle turbines have historically been non-base load units, we have concluded that it is appropriate to distinguish between the non-base load and base load subcategories in a way that recognizes the distinct roles of the different turbine designs on the market.

The challenge, however, is setting a threshold that will not distort the market. The future distinction between non-base load and base load units is unclear. For example, some commenters indicated that increased generation from intermittent renewable sources has created a perceived need for additional cycling and load following generation that will operate between the traditional roles of peaking and base load units. To fulfill this perceived need, some manufacturers have developed high-efficiency simple cycle turbines. These high-efficiency turbines have higher capital costs than traditional simple cycle turbine designs, but maintain similar flexibilities, such as the ability to start, stop, and change load rapidly. Other manufacturers have developed fast-start NGCC turbines to fill the same role. These newer NGCC designs have lower design efficiencies than NGCC designs intended to only operate as base load units, but are able to startup more quickly to respond to rapid changes in electricity demand. As a result of these new technological developments, both high-efficiency simple cycle and fast-start NGCC units can be used for traditional peaking applications, as well as for higher capacity applications, such as supporting the growth of intermittent renewable generation.

With the changing electric sector in mind, we set out to identify an appropriate percentage electric sales threshold to distinguish between non-base load and base load natural gas-fired units. Two factors were of primary importance to our decision. First, the threshold needed to be high enough to address commenters' concerns about the need to maintain flexibility for simple cycle units to support the growth of intermittent renewable generation. Second, the threshold needed to be low enough to avoid creating a perverse incentive for owners and operators to avoid the base load subcategory by installing multiple, less efficient turbines instead of fewer, more efficient turbines.

To determine the potential impact of intermittent renewable generation on the operation of simple cycle units, we examined the average electric sales of simple cycle turbines in the lower 48 states between 2005 and 2014 using information submitted to CAMD. We combined this data with information reported to the EIA on total in-state electricity generation, including wind and solar, from 2008 through 2014. We focused on data from the Southwest Power Pool (data approximated by EGUs in Nebraska, Kansas, and Oklahoma), Texas, and California. All of these regions have relatively large amounts of generation from wind and solar and experienced increases in the portion of total electric generation provided by wind and solar during the 2008–2014 period.

a. Southwest Power Pool

The portion of in-state generation from wind and solar in the Southwest Power Pool increased from 3 to 16 percent between 2008 and 2014. The average growth rate of wind and solar was 28 percent, while overall electricity demand grew 1 percent annually on average. Based on statements in some of the comments, we expected to see a large change in the operation of simple cycle turbines in this region. However, the average electric sales from simple cycle turbines only increased at an annual rate of 1.7 percent, and remained essentially unchanged at 3 percent of potential electric output between 2008 and 2014. Total generation from simple cycle turbines in the Southwest Power Pool increased slightly more, at an annual rate of 2.5 percent, which was the result of additional simple cycle capacity being added to address increased electricity demand.

This lack of a significant change in the operation of simple cycle turbines could be explained by the Southwest Power Pool's relatively large amount of exported power. If most of the region's renewable generation was being exported, the intermittent nature of this power would primarily impact other transmission regions. An alternate explanation, however, is that other generating assets are flexible enough to respond to the intermittent nature of wind and solar generation and that simple cycle turbines are not necessary to back up these assets to the degree some commenters suggested. If this is the case, then new simple cycle turbines may primarily continue to fill their historical role as peaking units going forward, while other technologies, such as fast-start NGCC units, may provide the primary back up capacity for new wind and solar.

b. Texas

The portion of in-state generation from wind and solar in Texas increased from 4 to 9 percent between 2008 and 2014. The average growth rate of wind and solar was 13 percent, while overall demand grew at an average rate of 2 percent annually. Similar to the Southwest Power Pool, the average electric sales of simple cycle turbines has remained relatively unchanged. In fact, the average electric sales of these turbines decreased at an annual rate of 1.1 percent. Total generation from simple cycle turbines increased at an annual rate of 6.6 percent, however, due to simple cycle capacity additions that occurred at approximately four times the rate one would expect from the growth in overall demand.

The most likely technologies to back up intermittent renewable generation have low incremental generating costs and can start up and stop quickly. Highly efficient simple cycle units meet these criteria. As such, the EPA has concluded that the most efficient simple cycle turbines in a given region are the most likely to support intermittent renewable generation. Focusing on these simple cycle turbines will address concerns raised by commenters about the future percentage electric sales of highly efficient simple cycle turbines and give an indication of the impact of increased renewable generation on non-base load units intended to back up wind and solar. There are two highly efficient intercooled simple cycle turbines installed in Texas. These two combustion turbines sell an average of 10 percent of their potential electric output annually, compared to an average of 3 percent for the remaining simple cycle turbines. No simple cycle turbine in Texas sold more than 25 percent of its potential electric output annually. The rapid growth in simple cycle capacity, but not overall capacity factors, could indicate that the additional generation assets are providing firm capacity for intermittent generation sources such as wind and solar, but that capacity is infrequently required. Based on the data, even highly efficient simple cycle turbines are expected to continue to sell less than one-third of their potential electric output.

c. California

The portion of in-state generation from wind and solar in California increased from 3 to 11 percent between 2008 and 2014. The average growth rate of wind and solar was 25 percent, while overall demand has remained stable. The operation of simple cycle turbines in California has changed more significantly than in the other evaluated regions. The average electric sales from simple cycle turbines increased from 5.1 to 5.9 percent, an annual rate increase of 4.5 percent. As in Texas, considerable additional simple cycle capacity has been added in recent years. The total capacity of simple cycle turbines is increasing at 15 percent annually even though overall demand has remained relatively steady. In addition, the newest simple cycle turbines are operating at higher capacity factors than the existing fleet of simple cycle turbines, resulting in an average increase in generation from simple cycle turbines of 21 percent. Many of the new additions are intercooled simple cycle turbines that may have been installed with the specific intent to back up wind and solar generation.

The average electric sales for the intercooled turbines ranged from 3 to 25 percent, with a 7 percent average. No simple cycle turbines in California have sold more than one-third of their potential electric output on an annual basis. The operation of simple cycle turbines that existed prior to 2008 has not changed significantly. Average electric sales for these turbines increased at an annual rate of 0.1 percent. This indicates that support for new renewable generation is being provided by new units and not by the installed base of simple cycle units. These units are still serving their historical role of providing power during peak periods of demand.

Based on our data analysis, the proposed one-third electric sales threshold would appear to offer sufficient operational flexibility for new simple cycle turbines. Existing NGCC units, other generation assets, and demand-response programs are currently providing adequate back up to intermittent renewable generation. In the future, however, existing NGCC units will likely operate at higher capacity factors. They will therefore be less available to provide back up power for intermittent generation. In addition, the amount of power generated by intermittent sources is expected to increase in the future. Both of these factors could require additional flexibility from the remaining generation sources to maintain grid reliability.

Even though fast-start NGCC units, reciprocating internal combustion engines, energy storage technologies, and demand-response programs are promising technologies for providing back up power for renewable generation, none of them historically have been deployed in sufficient capacity to provide the potential capacity needed in the future to facilitate the continued growth of renewable generation. While we anticipate that state and federally issued permits for new electric generating sources will consider the CO_2 benefits of these technologies compared to simple cycle turbines, the EPA has concluded at this time that it is appropriate to finalize a percentage electric sales threshold that provides additional flexibility for simple cycle turbines.

Specifically, we have concluded that a percentage electric sales threshold based on a unit's design net efficiency at standard conditions is appropriate. This is the sliding-scale approach on which we solicited comment. Several commenters supported this approach because it provides sufficient operational flexibility for new simple cycle and fast-start NGCC combustion turbines and simultaneously promotes the installation of the most efficient generating technologies. By allowing more efficient turbines to sell more electricity before becoming subject to the standard for the base load subcategory, the sliding scale should reduce the perverse incentive for owners and operators to install more lower-capital-cost, less-efficient units instead of fewer higher-capital-cost, more-efficient units. At the same time, the sliding scale should incentivize turbine manufacturers to design higher efficiency simple cycle turbines that owners and operators can run more frequently.

The net design efficiencies for aeroderivative simple cycle combustion turbines range from approximately 32 percent for smaller designs to 39 percent for the largest intercooled designs. The net design efficiencies of industrial frame units range from 30 percent for smaller designs to 36 percent for the largest designs. These efficiency values follow the methodology the EPA has historically used and are based on the higher heating value (HHV) of the fuel. In contrast, combustion turbine vendors in the U.S. often quote efficiencies based on the lower heating value (LHV) of the fuel. The LHV of a fuel is determined by subtracting the heat of vaporization of water vapor generated during combustion of fuel from the HHV. For natural gas, the LHV is approximately 10 percent lower than the HHV. Therefore, the corresponding LHV efficiency ranges would be 35 to 44 percent for aeroderivative designs and 33 to 40 percent for frame designs. We considered basing the percentage electric sales threshold on both the HHV and LHV. The EPA typically uses the HHV, but in light of commenters' concerns regarding uncertainty in the operation of non-base load units in the future, we opted to be conservative and use the LHV efficiency.

We anticipate that high-efficiency simple cycle and fast-start NGCC turbines will make up the majority of new capacity intended for non-base load applications. Based on the sliding-scale approach, owners and operators of new simple cycle combustion turbines will be able to sell between 33 to 44 percent of the turbine's potential electric output. Our analysis showed that 99.5 percent of existing simple cycle turbines have not sold more than one-third of their potential electric output on an annual basis. In addition, 99.9 percent of existing simple cycle turbines have not sold more than 36 percent of their potential electric output on an annual basis. The two simple cycle turbines that exceeded the 36 percent threshold had annual electric sales of 39 and 45 percent and are located in Montana and New York, respectively. As noted earlier, the most efficient simple cycle turbine currently available is 44 percent efficient and would accommodate the operations at the Montana facility. The only existing simple cycle turbine that exceeded the maximum allowable percentage electric sales threshold of 44 percent, which is based on current simple cycle designs, sold an abnormally high amount of electricity in 2014. It is possible that this unit was operating under emergency conditions. As explained below, the incremental generation due to the emergency would not have counted against the percentage electric sales threshold.

We are capping the percentage electric sales threshold at 50 percent of potential electric output for multiple reasons. First, NGCC emission rates are relatively steady above 50 percent electric sales, so there is no reason that a NGCC unit with sales greater than this amount should not have to comply with the output-based standard for the base load subcategory. Second, the net design efficiency of the fast-start NGCC units intended for peaking and intermediate load applications is 49 percent. As described earlier, this technology can serve the same purpose as high-efficiency simple cycle turbines. If we were to set a cap any lower than 50 percent, it could create a disincentive for owners and operators to choose this promising new technology.

Finally, the EPA solicited comment on excluding electricity sold during system emergencies from counting towards the percentage electric sales threshold. After considering the comments, we have concluded that this exclusion is necessary to provide flexibility, maintain system reliability, and minimize overall costs to the sector. We disagree with commenters that suggested that the EPA's existing enforcement discretion would be a viable alternative. An enforcement discretion-based approach would not provide certainty to the regulated community, public, and regulatory authorities on the applicability of the emission standards, which is a primary reason why we are finalizing the broad applicability approach. Moreover, system emergencies are defined events, so commenters' fears that the exclusion will be subject to abuse are overstated. Therefore, electricity sold during hours of operation when a unit is called upon to operate due to a system emergency will not be counted toward the percentage electric sales threshold. However, electricity sold by units that are not called upon to operate due to a system emergency (*e.g.,* units already operating when the system emergency is declared) will be counted toward the percentage electric sales threshold.

In summary, the EPA is finalizing the percentage electric sales criterion as a threshold to distinguish between two natural gas-fired combustion turbine subcategories. Specifically, all units that have electric sales greater than their net LHV design efficiencies (as a percentage of potential electric output) are base load units. All units that have electric sales less than or equal to their net LHV design efficiencies are non-base load units. We are capping the percentage electric sales threshold at 50 percent of potential electric output. This sliding-scale approach will limit the operation of the least efficient units, provide flexibility for renewable energy growth, and incentivize the development of more efficient simple cycle units.

3. Fuel-Based Subcategories

As described in Section IX.A.3.d, we are finalizing a version of the broad applicability approach. Under the broad applicability approach, the EPA solicited comment on a subcategorization approach based in part on natural gas-use. We received few comments on this issue. One of the comments we did receive was that combustion turbines that burn fuels other than natural gas have higher CO_2 emissions due to the higher relative carbon content of alternate fuels. Besides hydrogen,[533] natural gas has the lowest CO_2 emission rate on a lb/MMBtu basis of any fossil fuel. Therefore, burning fuels other than natural gas will result in a higher CO_2 emission rate. We interpret this comment to mean that, if we were to subcategorize based on fuel use, turbines that burn non-natural gas fuels should receive a less stringent emission standard.

For the reasons described in the applicability section, we have decided to set emission standards for all combustion turbines capable of burning natural gas, regardless of the actual fuel burned, to avoid the practical problems that would have arisen under the proposed approach. However, as commenters explained, multi-fuel-fired combustion turbines cannot achieve the emission standards achieved by natural-gas fired turbines. For this reason, it would not be reasonable to require affected EGUs to comply with a standard based on the use of natural gas during periods when significant quantities of non-natural gas fuels are being burned. If we did not subcategorize, owners and operators would not be able to combust other fuels in their turbines, including process gas, blast furnace gas, and petroleum-based liquid wastes, which might otherwise be wasted. In addition, without the ability to burn back up fuels during natural gas curtailments, grid reliability could be jeopardized. Therefore, we are finalizing a separate fuel-based subcategory for multi-fuel-fired combustion turbines. To distinguish between this subcategory and the natural gas-fired subcategories, we are using the same threshold as proposed. Specifically, combustion turbines that burn ninety percent or less natural gas on a 12-operating-month rolling average basis will be included in this subcategory and subject to a separate emission standard, which is discussed in Section IX.D.3.d.

[533] Hydrogen would only be considered a fossil fuel if it were derived for the purpose of creating useful heat from coal, oil, or natural gas.

C. Identification of the Best System of Emission Reduction

This section summarizes the EPA's proposed BSER determinations for stationary combustion turbines, provides a summary of the comments we received, and explains our final BSER determinations for each of the three subcategories we are now finalizing. For natural gas-fired stationary combustion turbines operating as base load units, we proposed and are finalizing the use of NGCC technology as the BSER. For the other two subcategories of affected combustion turbines—non-base load natural gas-fired combustion turbines and multi-fuel-fired combustion turbines—we are finalizing the use of clean fuels as the BSER.

1. Proposed BSER

We considered three alternatives in evaluating the BSER for base load natural gas-fired combustion turbines: (1) Partial CCS, (2) high-efficiency simple cycle aeroderivative turbines, and (3) modern, efficient NGCC turbines. We rejected partial CCS as the BSER because we concluded that we did not have sufficient information to determine whether implementing CCS for combustion turbines was technically feasible. We rejected high-efficiency simple cycle aeroderivative turbines as the BSER because this standalone technology does not provide emission reductions and generally is more expensive than NGCC technology for base load applications. In contrast, NGCC is the most common type of new fossil fuel-fired EGU currently being planned and built for generating base load power. NGCC is technically feasible, and NGCC units are currently the lowest-cost, most efficient option for new base load fossil fuel-fired power generation. After considering the options, the EPA proposed to find that modern, efficient NGCC technology is the BSER for base load natural gas-fired combustion turbines.

For non-base load natural gas-fired units and multi-fuel-fired units, we did not propose a specific BSER or associated numeric emission standards, but instead solicited comment on these issues.

2. Comments on the Proposed BSER for Base Load Natural Gas-Fired Combustion Turbines

This section summarizes the differing comments submitted on the proposed BSER for base load natural gas-fired combustion turbines. Some commenters supported partial CCS as the BSER, others supported advanced NGCC designs as the BSER, and others supported the proposed BSER.

a. Partial CCS

Some commenters stated that our proposed BSER analysis for stationary combustion turbines was inconsistent with our proposed BSER analysis for coal-fired units. They stated that the EPA had determined that the use of CCS was feasible for coal-fired generation based on current CCS projects under development at coal-fired generating stations, but did not come to the same conclusion for combustion turbines. These commenters stated that CO_2 removal is just as technologically feasible and economically reasonable for a natural gas-fired EGU as for a coal-fired EGU. While some of these commenters wanted the EPA to reconsider CCS as the BSER for NGCC, many of these commenters were attempting to prove that if the agency did not choose CCS as the BSER for NGCC units, then the agency should not for coal-fired units either.

Some commenters referenced the Northeast Energy Association NGCC plant in Bellingham, MA, which operated from 1991–2005 with 85–95 percent carbon capture on a 320 MW unit for use in the food and beverage industry, that was referred to in the proposal. This plant captured 330 tons of CO_2 per day from a 40 MW slip stream and was decommissioned as a result of financial difficulties, including rising gas prices and discontinuation of tax credits. According to these commenters, this plant provided sufficient proof that CCS technology is adequately demonstrated for NGCC units. Additionally, these commenters referred to other NGCC plants that are planned or in development that will incorporate CCS. The plants mentioned were the Sumitomo Chemical Plant in Japan, the Peterhead CCS project in Scotland, and the GE-Sargas Plant in Texas. The Sumitomo Chemical Plant has a base load NGCC unit with CCS operating on an 8 MW slip-stream that captures about 150 tons of CO_2 per day for commercial use in the food and beverage industry. This carbon capture system has been operating since 1994. The Peterhead CCS project in Scotland is in the planning stages. It is a collaboration between Shell and SSE to provide 320 MW of electricity to its customers from a base load NGCC unit with 90 percent carbon capture. The CO_2 will be transported to the depleted Goldeneye reservoir in the ocean where it will be stored and continuously monitored. The GE-Sargas Plant in Texas is a planned joint venture that does not currently have a location selected, but is intended to be a base load NGCC unit with CCS used for EOR.

These commenters also referenced reports authored by DOE, NETL, the Clean Air Task Force (CATF), CCS Task Force, ICF Inc., and Global CCS Institute, suggesting that, because CCS technology for NGCC is included in these reports, it is adequately demonstrated. Some commenters referred to a DOE/NETL study that suggested that the cost of CCS for NGCC units would be more cost-effective than for coal-fired EGUs. One non-industry commenter emphasized that a technology does not have to be in use to be considered adequately demonstrated.

In addition, some commenters disagreed with the EPA's decision to treat combustion turbines differently than coal-fired units with respect to CCS on the basis that combustion turbines startup, shutdown, and cycle load more frequently than coal-fired units. According to these commenters, the operating characteristics of combustion turbines do fluctuate, but so do those of coal-fired units. Another commenter said that even if NGCC operations vary more than they do for coal-fired units, it is not an impediment to using CCS because combustion turbine operators could bypass the carbon capture system during startup and shutdown modes (which are typically shorter and less intensive efforts compared to the startup or shutdown of a coal facility) and then employ the carbon capture system when operating normally. One commenter stated that most future base load fossil fuel-fired generation will be NGCC and that not making CCS the BSER for NGCC would result in significant CO_2 emissions.

Other commenters supported the EPA's determination that CCS is not the BSER for combustion turbines. These commenters said that CCS is not adequately demonstrated for combustion turbines because none are currently operating, under construction, or in the advanced stages of development. They also noted that CCS would have to be demonstrated for the range of facilities included in the regulated source category, which they alleged includes both simple cycle and NGCC units. They specifically noted that the Bellingham, MA demonstration facility was not a full-scale commercial NGCC power plant operating with CCS.

These commenters agreed with the EPA that CCS does not match well with the operating flexibilities of NGCC and simple cycle units. They agreed with the EPA that frequent cycling restricts the efficacy of CCS on these units, a problem which would only get worse as more renewable energy sources are integrated into the grid. These commenters added that NGCC units operate differently than coal-fired units because the former start, stop, and cycle frequently, whereas the latter tend to operate at relatively steady loads and do not start and stop frequently. They stated that even if technical barriers could be overcome, the application of CCS to combustion turbines would be more costly (compared to the application of CCS to coal-fired units) on a dollars-per-ton basis. In addition, these commenters said that other industries' experience with CCS could not be transferred to NGCC units due to differences in flue gas CO_2 concentration.

Some commenters stated that CAA section 111(a) requires the EPA to account not only for the cost of achieving emission reductions, but also for impacts on energy requirements and the environment. The commenters cited to *Sierra Club* v. Costle, where the D.C. Circuit observed that the EPA ''must exercise its discretion to choose an achievable emission level which represents the best balance of economic, environmental, and energy considerations.'' [534] The commenters stated that requiring CCS on combustion turbines would adversely affect the nation's energy needs and the environment because imposing CCS on combustion turbines would invariably delay the emission reductions that can be obtained from new NGCC projects that displace load from older, less efficient generating technologies. In addition, the commenters stated that, because combustion turbines are projected to provide a significant share of new power generation, the EPA should recognize that requiring CCS on these units would have a disproportionally higher impact on electricity prices when compared to the projected number of new coal-fired projects. These commenters concluded that the EPA could not determine that CCS is the BSER for combustion turbines without producing severe and unacceptable consequences for the availability of affordable electricity in the U.S.

b. NGCC Turbines

Some commenters stated that the proposed BSER analysis should have reflected the emission rates achieved by the latest designs deployed at advanced, state-of-the-art NGCC installations. These commenters stated that advanced NGCC technologies are the best system

[534] *Sierra Club* v. *Costle*, 657 F.2d 298, 330 (D.C. Cir. 1981).

for reducing CO_2 emissions with no negative environmental impacts and no negative economic impacts on rate payers. They stated that advanced NGCC technologies are capable of achieving emission rates that are 8 percent lower than conventional NGCC facilities. They also said that the majority of existing sources that do not deploy these advanced technologies are currently able to meet the standard and that the proposal failed to explain why these lower-emitting advanced technologies that are more than adequately demonstrated were not selected as the BSER.

c. Simple Cycle Turbines

Many commenters opposed the EPA's proposal to set emission standards for combustion turbines based on their function rather than based on their design. These commenters stated that the EPA's determination that NGCC technology is the BSER for base load natural gas-fired combustion turbines would apply equally to simple cycle turbines if they sell electricity in excess of the percentage electric sales threshold. They pointed to the word ''achievable'' in CAA section 111(a)(1) and stated that applying an emission standard based on NGCC technology to simple cycle units was legally indefensible because simple cycle units cannot achieve emission rates as low as NGCC units. In contrast, many other commenters agreed with the EPA's basic approach and stated that NGCC technology should be the BSER for base-load functions, while simple cycle technology should be the BSER for peak-load functions.

3. Comments on Non-Base Load and Multi-Fuel-Fired Combustion Turbines

Multiple commenters suggested that high efficiency simple cycle or fast-start NGCC technologies should be the BSER for non-base natural gas-fired load units. They explained that high efficiency simple cycle units and fast-start NGCC units are actually more efficient when serving non-base load demand than NGCC units that are designed strictly for base load operation. Some commenters also suggested that we should subcategorize multi-fuel-fired combustion turbines, but did not provide any specific technologies that should be considered in the BSER analysis.

4. Identification of the BSER

After our evaluation of the comments and additional analysis, we identified the BSER for each subcategory of combustion turbine that we are finalizing: base load natural gas-fired units, non-base load natural gas-fired units, and multi-fuel-fired units.

a. Base Load Natural Gas-Fired Units

As described in the proposal, we evaluated CCS, NGCC, and high-efficiency simple cycle combustion turbines as the potential BSER for this subcategory. We selected NGCC as the BSER because it met all the BSER criteria. This section describes our response to issues raised by commenters and our rationale for maintaining that NGCC is the BSER for base load natural gas-fried combustion turbines.

(1) Partial CCS

Some commenters stated that CCS could be applied equally to both coal-fired and natural gas-fired EGUs. To support this conclusion, the commenters pointed to a retired NGCC-with-CCS demonstration project, as well as a few overseas projects and projects in the early stages of development. While we have concluded that these commenters made strong arguments that the technical issues we raised at proposal could in many instances be overcome, we have concluded that there is not sufficient information at this time for us to determine that CCS is adequately demonstrated for all base load natural-gas fired combustion turbines.

While the commenters make a strong case that the existing and planned NGCC-with-CCS projects demonstrate the feasibility of CCS for NGCC units operating at steady state conditions, many NGCC units do not operate this way. For example, the Bellingham, MA and Sumitomo NGCC units cited by the commenters operated at steady load conditions with a limited number of starts and stops, similar to the operation of coal-fired boilers.[535] In contrast, our base load natural gas-fired combustion turbine subcategory includes not only true base load units, but also some intermediate units that cycle more frequently, including fast-start NGCC units that sell more than 50 percent of their potential output to the grid. Fast-start NGCC units are designed to be able to start and stop multiple times in a single day and can ramp to full load in less than an hour. In contrast, coal-fired EGUs take multiple hours to start and ramp relatively slowly. These differences are important because we are not aware of any pilot-scale CCS projects that have demonstrated how fast and frequent starts, stops, and cycling will impact the efficiency and reliability of CCS. Furthermore, for those periods in which a NGCC unit is operating infrequently, the CCS system might not have sufficient time to startup. During these periods, no CO_2 control would occur. Thus, if the NGCC unit is intended to operate for relatively short intervals for at least a portion of the year, the owner or operator could have to oversize the CCS to increase control during periods of steady-state operation to make up for those periods when no control is achieved by the CCS, leading to increased costs and energy penalties. While we are optimistic that these hurdles are surmountable, it is simply premature at this point to make a finding that CCS is technically feasible for the universe of combustion turbines that are covered by this rule.

Notably, the Department of Energy has not yet funded a CCS demonstration project for a NGCC unit, and no NGCC-with-CCS demonstration projects are currently operational or being constructed in the U.S. In contrast, multiple CCS demonstration projects for coal-fired units are in various stages of development throughout the U.S., and a full-capture system is in operation at the Boundary Dam facility in Canada. See Sections V.E and D above.

One commenter suggested that not having CCS as the BSER for combustion turbines would ultimately halt the development of CCS in the U.S. We disagree. A number of coal-fired power plants are currently being built with CSS, while some existing plants are considering CCS retrofits. Moreover, the NSPS sets the minimum level of control for new sources. We expect that state air agencies and other air permitting authorities will evaluate CCS when permitting new NGCC power plants, taking into consideration case-specific parameters, like operating characteristics, to determine whether CCS could be BACT or LAER in specific instances. While the NGCC-with-CCS units that currently are in the planning stages do not provide us with enough assurance to determine that CCS is adequately demonstrated for combustion turbines, it is our expectation that these units and others to come will provide additional information for both permitting reviews and the next NSPS review in eight years.

(2) NGCC Turbines

Regarding the advanced NGCC technologies advocated by several commenters, the EPA has concluded

[535] As explained in Section V.J above, a new fossil fuel-fired steam generating EGU would, most likely, be built to serve base load power demand exclusively and would not be expected to routinely startup, shut down, or ramp its capacity factor in order to follow load demand. Thus, planned start-up and shutdown events would only be expected to occur a few times during the course of a 12-operating-month compliance period.

that the term ''advanced'' simply refers to incremental improvements to traditional NGCC designs, not a new and unique technology. These incremental improvements include higher firing temperatures in the turbine engine, increasing the number of steam pressures, and adding a reheat cycle to the steam cycle. The emission rates achieved by these so-called ''advanced'' technologies were included within the data set of newer NGCC designs that we used to establish the final emission standards. In addition, our review of the operating data for NGCC power blocks installed since 2000 indicates that a unit's mode of operation in response to system demand (*e.g.,* capacity factor) affects efficiencies achieved to the extent that we cannot evaluate the impact of particular subcomponents used within the power block. As a result, a conventional NGCC power block located in a region of the country where system demand requires the power block to run continuously at a steady high load can achieve higher efficiencies than an ''advanced'' NGCC power block located in a region where system demand requires the power block to cycle on and off to match system demand. For this reason, our data set included a large population of technologies and load conditions to ensure that new NGCC power blocks can achieve the final emission standards in all regions of the country.

As we explained in the proposal, NGCC technology meets all of the BSER criteria. For base load functions, NGCC units are technically feasible, cost-effective (indeed, less expensive than simple cycle combustion turbines), and have no adverse energy or environmental impacts. Moreover, NGCC units reduce emissions because they have a lower CO_2 emission rate than simple cycle units. Finally, selecting NGCC as the BSER will promote the development of new technology, such as the incremental improvements advocated by the commenters, which will further reduce emissions in the future.

Some commenters suggested that the costs and efficiency impacts of startup and shutdown events are higher for NGCC units than for simple cycle units. Consequently, we refined the LCOE costing approach used at proposal by adding these additional costs and efficiency impacts to our cost comparison. Even accounting for these new costs and impacts, we found that NGCC technology results in a lower cost of electricity than simple cycle technology when a unit's electric sales exceed approximately one-third of its potential electric output. The final percentage electric sales criterion for the base load natural gas-fired combustion turbine subcategory is based on the sliding scale. This means that the dividing line between the base load subcategory and the non-base load subcategory will change depending on a unit's nameplate design efficiency. For a conventional simple cycle turbine, the base load subcategory will begin at around 33 percent electric sales, while for a newer fast-start NGCC turbine, the base load subcategory will begin at approximately 50 percent electric sales. Anywhere within this range, our cost calculations have shown that NGCC technology is more cost-effective than simple cycle technology. Therefore, we are finalizing our determination that modern, efficient NGCC technology is the BSER for base load natural-gas fired combustion turbines.

(3) Simple Cycle Turbines

Many commenters mistakenly thought that the EPA proposed to require some simple cycle combustion turbines to meet an emission standard of 1,000 lb CO_2/MWh-g, a level that they assert is unachievable. On the contrary, the EPA is not finding that NGCC technology and a corresponding emission standard of 1,000 lb CO_2/MWh-g is the BSER for simple cycle turbines. Instead, the EPA is finding that NGCC technology is the BSER for base load turbine applications. This means that if an owner or operator wants to sell more electricity to the grid than the amount derived from a unit's nameplate design efficiency calculated as a percentage of potential electric output, then the owner or operator should install a NGCC unit. If the owner or operator elects to install a simple cycle turbine instead, then the practical effect of our final standards will be to limit the electric sales of that unit so that it serves primarily peak demand, not to subject it to an unachievable emission standard.

b. Non-base Load Natural Gas-Fired Load Units

To identify the BSER for non-base load natural gas-fired units, we evaluated a range of technologies, including partial CCS, high-efficiency NGCC technology designed for base load applications, fast-start NGCC, high-efficiency simple cycle units (*i.e.,* aeroderivative turbines), and clean fuels. For each of these technologies, we considered technical feasibility, costs, energy and non-air quality impacts, potential for emission reductions, and ability to promote technology.

While CCS would result in emission reductions and promote the development of new technology, we concluded that CCS does not meet the BSER criteria because the low capacity factors and irregular operating patterns (*e.g.,* frequent starting and stopping and operating at part load) of non-base load units make the technical challenges associated with CCS even greater than those associated with base load units. In addition, because the CCS system would remain idle for much of the time while these units are not running, CCS would be less cost-effective for these units than for base load units.

We have also concluded that the high-efficiency NGCC units designed for base load applications do not meet any of the BSER criteria for non-base load units. First, non-base load units need to be able to start and stop quickly, and NGCC units designed for base load applications require relatively long startup and shutdown periods. Therefore, conventional NGCC designs are not technically feasible for the non-base load subcategory. Also, non-base load units operate less than 10 percent of the time on average. As a result, conventional NGCC units designed for base load applications, which have relatively high capital costs, will not be cost-effective if operated as non-base load units. In addition, it is not clear that a conventional NGCC unit will lead to emission reductions if used for non-base load applications. As some commenters noted, conventional NGCC units have relatively high startup and shutdown emissions and poor part-load efficiency, so emissions may actually be higher compared with simple cycle technologies that have lower overall design efficiencies but better cycling efficiencies. Finally, requiring conventional NGCC units as the BSER for non-base load combustion turbines would not promote technology because these units would not be fulfilling their intended role. In fact, it could hamper the development of technologies with lower design efficiencies that are specifically designed to operate efficiently as non-base load units (*i.e.,* high-efficiency simple cycle and fast-start NGCC units). For all these reasons, we have concluded that conventional NGCC units designed for base load applications are not the BSER for non-base load natural gas-fired units.

Compared to conventional NGCC technology, fast-start NGCC units have lower design efficiencies, but are able to start and ramp to full load more quickly. Therefore, it is possible that requiring fast-start NGCC as the BSER for non-base load units would result in emission reductions and further promote the development of fast-start NGCC technology, which is relatively new and advanced. However, because the majority of non-base load combustion turbines operate less than 10 percent of the time, it would be cost-prohibitive to require fast-start NGCC, which have relatively high capital costs compared to simple cycle turbines, as the BSER for all non-base load applications. Also, as we explained above in Section IX.B.2, we do not have sufficient emissions data for fast-start NGCC units operating over the full range of non-base load conditions (*e.g.,* peaking, cycling, etc.), so we would not be able to establish a reasonable emission standard.

High-efficiency simple cycle turbines are primarily used for peaking applications. High-efficiency simple cycle turbines often employ aeroderivative designs because they are more efficient at a given size and are able to startup and ramp to full load more quickly than industrial frame designs. Requiring high-efficiency simple cycle turbines as the BSER could result in some emission reductions compared with conventional simple cycle turbines. It would also promote technology development by incentivizing manufacturers to increase the efficiency of their simple cycle turbine models. However, aeroderivative designs have higher initial costs that must be weighed against the specific peak-load profiles anticipated for a particular new non-base load unit. Many utility companies have elected to install the heavier industrial frame turbines because the ramping capabilities of aeroderivative turbines are not required for their system demand profiles (*i.e.,* the speed and durations of daily changes in electricity demand), and the fuel savings do not justify the higher initial costs. We currently do not have precise enough costing information to compare the cost-effectiveness of aeroderivative turbines and industrial frame turbines for all non-base load applications. Determining cost-effectiveness is further complicated because the efficiencies of the available aeroderivative and industrial frame technologies significantly overlap. For example, the efficiencies of aeroderivative turbines range from 32 to 39 percent, while the efficiencies of industrial frame turbines range from 30 to 36 percent. Based on these cost uncertainties, we cannot conclude that high-efficiency simple cycle turbines are the BSER for natural gas-fired non-base load applications at this time.

The final option that we considered for the BSER was clean fuels, specifically natural gas with a small allowance for distillate oil. The use of clean fuels is technically feasible for non-base load units. Based on available EIA data,[536] natural gas comprises more than 96 percent of total heat input for simple cycle combustion turbines. In addition, natural gas is frequently the lowest cost fossil fuel used in combustion turbines, so it is cost-effective. Clean fuels will also result in some emission reductions by limiting the use of fuels with higher carbon content, such as residual oil. Finally, the use of clean fuels will not have any significant energy or non-air quality impacts. Based on these factors, the EPA has determined that the BSER for non-base load natural gas-fired units is the use of clean fuels, specifically natural gas with a small allowance for distillate oil. Natural gas has approximately thirty percent lower CO_2 emissions per million Btu than other fossil fuels commonly used by utility sector non-base load units.

c. Multi-Fuel-Fired Units

To identify the BSER for multi-fuel-fired units, we again evaluated CCS, NGCC technology, high-efficiency simple cycle units (*i.e.,* aeroderivative turbines), and clean fuels. For each of these technologies we considered technical feasibility, costs, energy and non-air quality impacts, emission reductions, and technology promotion. For many of the same reasons we provided above in our discussion of the BSER for non-base load natural gas-fired combustion turbines, only clean fuels meets the BSER criteria for multi-fuel-fired units.

While CCS would result in emission reductions and the promotion of technology, we concluded that CCS does not meet the BSER criteria because multi-fuel-fired units tend to start, stop, and operate at part load frequently. Also, there are impurities and contaminants in some alternate fuels which make the technical challenges of applying CCS to multi-fuel-fired units greater than for natural gas-fired units.

In regards to NGCC technology, we have concluded that it is technically feasible, would result in emission reductions, is cost-effective, and would promote the development of technology. However, a BSER determination based on the use of NGCC technology could pose challenges for facilities operating in remote locations and certain industrial facilities. In remote locations, the construction of a NGCC facility is often not practical because it requires larger capital investments and significant staffing for construction and operation. In contrast, simple cycle turbines are cheaper and can be operated with minimal staffing. Also, many industrial facilities do not have the space available to build a HRSG and the associated cooling tower. Therefore, requiring NGCC as the BSER could have unforeseen energy impacts at these types of facilities. Moreover, these same kinds of facilities also burn by-product fuels. Faced with a decision to install an NGCC unit, these facilities might seek alternative energy options, which could lead to increased flaring or venting of by-product fuels because they are no longer being burned onsite for energy recovery. Therefore, in light of these potential energy and non-air quality impacts, we have concluded that NGCC technology is not the BSER for multi-fuel-fired combustion turbines.

Similarly, while high-efficiency simple cycle turbines would result in emission reductions and promote the advancement of this technology, we are not confident that high-efficiency simple cycle units are technically feasible or cost-effective for this subcategory. Aeroderivative turbines are not as flexible with regards to what fuels that can be burned. Because by-product fuels vary in composition, it is not clear that all by-products fuels could be burned in a high-efficiency simple cycle turbine. In addition, even if a by-product fuel could be burned in an aeroderivative turbine, we do not have information on the potential for increased maintenance costs, so we cannot determine whether using high-efficiency simple cycle turbines would be cost-effective.

The final option that we considered for the BSER was clean fuels. The use of clean fuels is technically feasible and cost-effective. The use of clean fuels also provides an environmentally beneficial alternative to the flaring or venting of by-product fuels and limits the use of dirtier fuels with higher CO_2 emission rates, such as residual oils. Clean fuels also promote technology development by allowing manufacturers to develop new combustion turbine designs that are capable of burning by-product fuels that currently cannot be burned in combustion turbines. Finally, the use of clean fuels does not have any significant energy or non-air quality impacts. Based on these factors, the EPA has determined that the BSER for multi-fuel-fired combustion turbines is the use of clean fuels.

D. Achievability of the Final Standards

We are finalizing emission standards for three subcategories of combustion turbines. Specifically, units that sell electricity in excess of a threshold based on their design efficiency and that burn more than 90 percent natural gas (*i.e.,* base load natural gas-fired units) will be

[536] *http://www.eia.gov/electricity/data/eia923/.*

subject to an output- based standard. The output-based standard is based on the performance of existing NGCC units and takes into account a range of operating conditions, future degradation, etc. Units not meeting either the percentage electric sales or natural gas-use criteria (*i.e.,* non-base load natural gas-fired and multi-fuel units, respectively) will be subject to an input-based standard based on the use of clean fuels. This section summarizes what emission standards we proposed and related issues we solicited comment on, describes the comments we received regarding the proposed emission standards and our responses to those comments, and provides our rationale for the final emission standards.

1. Proposed Standards

For large newly constructed, modified, and reconstructed stationary combustion turbines (base load rating greater than 850 MMBtu/h), we proposed an emission standard of 1,000 lb CO_2/MWh-g. For small stationary combustion turbines (base load rating of 850 MMBtu/h or less), we proposed an emission standard of 1,100 lb CO_2/MWh-g. We also solicited comment on a range of 950–1,100 lb CO_2/MWh-g for large stationary combustion turbines and a range of 1,000–1,200 lb CO_2/MWh-g for small stationary combustion turbines.

In addition, we solicited comment on increasing the size distinction between large and small stationary combustion turbines to 900 MMBtu/h to account for larger aeroderivative designs; increasing the size distinction to 1,000 MMBtu/h to account for future incremental increases in base load ratings; increasing the size distinction to between 1,300 to 1,800 MMBtu/h; and eliminating the size subcategories altogether. To account for potential reduced efficiencies when units are not operating at base load, we also solicited comment on whether a separate, less stringent standard should be established for non-base load combustion turbines.

2. Comments

As described previously, we are not finalizing the size-based subcategories that we proposed and instead are finalizing emission standards for sales- and fuel-based subcategories. Specifically, we are finalizing emission standards for three subcategories of stationary combustion turbines: base load natural-gas fired units, non-base load natural gas-fired units and multi-fuel-fired units. The relevant comments concerning the emission standards for the first two subcategories are discussed below. Any comments we received supporting tiered emission standards are included in the discussion of non-base load natural gas-fired units. We did not receive comments on an appropriate emission standard for multi-fuel-fired units.

a. Emission standards for Base Load Natural Gas-Fired Units

Many commenters stated that the proposed emission standards did not properly take into account the losses in efficiency that occur due to long-term degradation over multiple decades, operation at non-base load conditions (load cycling, frequent startups and shutdowns, and part-load operations), site-specific factors such as ambient conditions and cooling technology, and secondary fuel use (*e.g.,* distillate oil). These commenters stated that the EPA should conduct a more comprehensive analysis that addresses worst-case conditions for each of these factors. They also stated that all of the units included in the analysis supporting the proposal were relatively new and therefore have experienced limited degradation. The commenters stated that, while some degradation in efficiency can be recovered during periodic maintenance outages, it is not always possible or feasible to repair a degraded component immediately because repairs often involve extended outages that must be scheduled well in advance. They stated that a new unit that initially could meet the standard at base load conditions can experience increasing heat rates with age even when adhering to the manufacturer's recommended maintenance program.

Some commenters stated that the proposed standards were derived by looking at emissions data from years with historically low natural gas prices. They surmised that the NGCC units were taking advantage of these prices by running at historically high capacity factors and concluded that the efficiencies and CO_2 emission rates underlying the proposed standards were not representative of periods with higher natural gas prices. Other commenters said that many NGCC units are increasingly required to cycle and operate at lower capacities (compared to the proposal's baseline) to accommodate hourly variations in intermittent renewable generation. They anticipated that this type of generation will increase, requiring NGCC units to start, stop, and operate at part load more frequently than in the past, increasing CO_2 emissions.

Some commenters indicated that, during startup, combustion turbines must be operated at low load for extended periods to gradually warm up the HRSG to minimize thermal stresses on pressure vessels and boiler tubes. During these startup periods, significant CO_2 emissions occur, but steam production is not sufficient for the steam turbine generator to produce electricity. They also stated that a similar situation occurs during shutdown when the steam cycle does not generate electricity, but the combustion turbine is still combusting fuel as it proceeds through the shutdown process. These commenters recommended that the EPA could address these issues by creating a subcategory for NGCC units that cycle and operate at intermediate load.

Many commenters said that site-specific factors can often preclude operators from achieving design efficiencies based on ISO conditions. These factors include high elevations, high ambient temperatures, and cooling system constraints. They stated that local water temperatures can impact condenser operating pressure and heat rates. They also said that areas with limited water resources could require systems that rely on air-cooled condensers, which cannot achieve thermal efficiencies comparable to water-cooled plants. These commenters stated that the final rule should include provisions for addressing site-specific constraints that preclude individual affected EGUs from achieving the emissions rates achieved on average by other sources.

Some commenters stated that the proposed standards for modified and reconstructed combustion turbines would foreclose future opportunities for operators to undertake projects to restore the performance of both degraded units subject to the NSPS and existing, pre-NSPS units. They said that it is not possible to bring older combustion turbines (built prior to the year 2000) up to the efficiency levels of modern units because many newer technological options that deploy higher temperatures are not available for pre-2000 combustion turbines.

Commenters from the power sector generally supported increasing the standards to 1,100 lb CO_2/MWh-g and 1,200 lb CO_2/MWh-g for the newly constructed large and small turbines, respectively. They also advocated finalizing standards for modified and reconstructed standards that are 10 percent higher than the final standards for new sources because combustion turbines constructed prior to 2000 were not included in the EPA's analysis.

Conversely, some commenters stated that the proposed standards for combustion turbines do not reflect the emission rates that are achievable by modern, efficient NGCC power blocks. These commenters stated that the appropriate standard, consistent with Congressional objectives under CAA section 111, should be 800 lb CO_2/MWh-g based on the performance of the lowest emitters in the CAMD database. Some commenters stated that a standard of 850 lb CO_2/MWh-g reflects BSER for high-capacity factor units because half of the NGCC units in the CAMD database are achieving this level of emissions. One commenter from the power sector who operates NGCC power plants stated that the final standard for new large combustion turbines should be 925 lb CO_2/MWh-g. Another commenter also supported an emission standard of 925 lb CO_2/MWh-g, which is consistent with recent BACT determinations in the state of New York. Several other commenters stated that a reasonable standard for new large combustion turbines should be 950 lb CO_2/MWh-g and that the final standard for new small combustion turbines should be 1,000 lb CO_2/MWh-g. Numerous commenters stated that the final standards for new sources should not exceed 1,000 lb CO_2/MWh-g for either large or small combustion turbines. Other commenters stated that, because the standards were developed based on emission rates that are being achieved by the majority of existing units, the final standards should be the same for new, modified, and reconstructed units.

b. Emission Standards for Non-Base Load Natural Gas-Fired Units and Multi-Fuel-Fired Units

Many commenters stated that the EPA cannot finalize ''no emission standard'' for non-base load units, which the EPA solicited comment on in the broad applicability approach. They argued that this approach was not consistent with the definition of ''standard of performance'' in CAA section 111(a)(1), which requires there to be an ''emission limitation'' that reflects a ''system of emission reduction.'' Some commenters recommended that non-base load units should be subject to work practice standards, such as operating safely with good air pollution control practices, including CO_2 monitoring and reporting requirements. Other commenters pointed to recent PSD permits that include tiered emission limits for the different roles served by combustion turbines. They cited BACT limits from 1,328 to 1,450 lb CO_2/MWh-g for peaking units. One commenter supported tiered limits consistent with recent BACT determinations in the state of New York, which include limits for simple cycle combustion turbines of 1,450 lb CO_2/MWh-g. An air quality regulator from a state with rapidly increasing renewable generation supported a limit of 825 lb CO_2/MWh-g for all base load NGCC units; 1,000 lb CO_2/MWh-g for large intermediate load NGCC units; 1,100 lb CO_2/MWh-g for small intermediate load NGCC units. This commenter also recommended that the EPA set a numerical limit specifically for peaking units after the completion of a peaking unit-specific BSER analysis. Several commenters supported tiered standards based on capacity factor. They proposed 825 lb CO_2/MWh-g for base load units (those operating over 4,000 hours annually), 875 lb CO_2/MWh-g for intermediate and load-following units (those operating between 1,200 and 4,000 hours annually), and 1,100 lb CO_2/MWh-g for peaking units (those operating less than 1,200 hours per year).

3. Final Standards

a. Newly Constructed Base Load Natural Gas-Fired Units

In evaluating the achievability of the base load natural gas-fired emission standard, we focused on three types of data. Specifically, we looked at existing NGCC emission rates, recent PSD permit limits for CO_2 emissions, and NGCC design efficiency data and specifications. Based on this analysis, we have concluded that an emission rate of 1,000 lb CO_2/MWh-g is appropriate for all base load natural gas-fired combustion turbines, regardless of size.

Since the standards were proposed, the EPA has expanded the NGCC emission rate analysis that supported the proposed emission standards to include emissions information for NGCC units that commenced operation in 2011, 2012, and 2013, and updated the emissions data to include emissions through 2014. In our analysis, we evaluated 345 NGCC units with online dates ranging from 2000 to 2013. The analysis included emissions data from 2007 to 2014 as submitted to the EPA's CAMD. The average maximum 12-operating-month CO_2 emission rate for all NGCC units was 897 lb CO_2/MWh-g, with individual unit maximums ranging from 751 to 1,334 lb CO_2/MWh-g.

Consistent with our proposed size-based subcategories, we also reviewed the emissions data for small and large NGCC units separately. For small units, we evaluated emissions data from 17 NGCC units with heat input ratings of 850 MMBtu/h or less. These units had an average maximum 12-operating-month CO_2 emission rate of 953 lb/MWh-g. Individual unit maximum emission rates ranged from 898 to 1,175 lb CO_2/MWh-g. Two of the units had a maximum emissions rate equal to or greater than 1,000 lb CO_2/MWh-g.[537] However, one of the units with a maximum emission rate above 1,000 lb CO_2/MWh-g was only selling approximately 20 percent of its potential electric output (significantly below the design-specific percentage electric sales threshold) when the emission rate occurred. If this unit were a new unit, the applicable emission standard would be the heat input-based clean fuels standard, and the unit would not be out of compliance. Therefore, 16 of the 17 existing small NGCC units have demonstrated that an emission rate of 1,000 lb CO_2/MWh-g is achievable. In addition, the six newest units, which commenced construction between 2007 and 2012, all have maximum 12-operating-month emission rates of less than 950 lb CO_2/MWh-g. While these units might not be old enough to have experienced degradation, their maximum emission rates demonstrate that the final standard of 1,000 lb CO_2/MWh-g includes a significant compliance margin for any future degradation.

For large units, the average maximum 12-operating-month emission rate was 895 lb CO_2/MWh-g, with individual unit maximum emission rates ranging from 751 to 1,334 lb CO_2/MWh-g. Twenty-three of the 328 large NGCC units had maximum 12-operating-month emission rates greater than 1,000 lb CO_2/MWh-g. While we do not have precise design efficiency information for each of these units, and thus cannot calculate the precise percentage electric sales threshold to which each unit would be subject, it appears that all of the emission rates in excess of 1,000 lb CO_2/MWh-g occurred during periods when electric sales were low and would be below the threshold. Thus, if these units were new units, they would only have to comply with the heat input-based clean fuels standard. Therefore, essentially all existing NGCC units would have been in compliance with the final emission standard. We note also that there are 51 new NGCC units that have started operation since 2010, and the average maximum 12-operating-month emission rate for these units is 833 lb CO_2/MWh-g. Therefore, the final emission standard includes a very significant compliance margin to account for any potential future degradation of large units.

[537] For emission standards of 1,000 lb CO_2/MWh-g and above, the emission standard uses three significant figures. See Section X.D.

To evaluate degradation further, the EPA reviewed the emission rate information for the 55 oldest NGCC units in our data set (*i.e.,* units that came online in 2000 and 2001). According to the commenters, we should expect to see degradation when reviewing the annual emissions data for these turbines because they are 14 to 15 years old. However, we did not see any sign of degradation. The CO_2 rates for these turbines have little standard deviation between 2007 and 2014. In addition, there were many instances where the CO_2 emission rate of a unit actually decreased with age. This indicates that the efficiency of the unit is increasing, possibly as a result of good operating and maintenance procedures or upgrades to equipment that improved efficiency beyond the original design. Based on these findings, we have concluded that our analysis adequately accounts for potential degradation.

We also evaluated the impact of elevation, ambient temperature, cooling type, and operating conditions (startups, shutdowns, and average run time per start) because commenters indicated that these could affect a unit's ability to achieve the standard. We saw little correlation between elevation or ambient temperature and emission rate. In addition, any correlation was relatively small and would have an insignificant impact on the ability of a unit to achieve the final standard. We identified 32 large NGCC units with dry cooling towers. The average maximum 12-operating-month emission rate for this group of units was 875 lb CO_2/MWh. This rate was actually lower than the average rate for the large NGCC group as a whole. Based on these findings, we have concluded that the final emission standard will not limit the use of dry cooling technologies. Finally, the EPA evaluated the impact of run time per start, average duty cycle, and number of starts on emission rates. While these factors do influence emission rates, the non-base load natural gas-fired subcategory inherently addresses efficiency issues related to operating conditions.

In addition to evaluating existing NGCC emissions data, the EPA reviewed the CO_2 emission limits included in PSD preconstruction permits issued since January 1, 2011. We evaluated all permit limits over an annual period. In total, we identified 31 major source PSD permits with 39 discrete limits on CO_2 emissions. Eight of the limits were expressed in terms of lb/h or tons per year, so we did not include them in the analysis. In addition, one CHP unit that generates electricity and supplies steam to a chemical plant was in the data set. This facility had a permit limit of 1,362 lb CO_2/MWh based only on gross electrical output and does not account for useful thermal output. Therefore, we did not include it in the analysis either. Finally, we excluded two permits that did not clearly specify if the output-based standard was on a gross or net basis.

The remaining 28 permit limits were expressed in lb CO_2/MWh or a heat rate basis that could be converted to lb CO_2/MWh. Eight permit limits were based on net output, ranging from 774–936 lb CO_2/MWh-n. The lowest emission limit was for a hybrid power plant with a solar component that could contribute up to 50 MW. Twenty permit limits were based on gross output, ranging from 833–1,100 lb CO_2/MWh-g. Of these 28 permit limits, the only limit in excess of our final emission standard of 1,000 lb CO_2/MWh-g is for a relatively small NGCC unit (base load rating of 366 MMBtu/h) that commenced construction prior to the proposal and thus will not be subject to the requirements of this final rule.

Each of the permit limits discussed above that is 1,000 lb CO_2/MWh or less includes all periods of operation, including startup, shutdown, and malfunction events. In addition, each permit limit was set after back up and additional fuel use were taken into consideration. While some permits restrict fuel use to only natural gas, others allow limited usage (duration and type) of back up and other fuels. For example, the Pioneer Valley Energy Center has unrestricted use of natural gas, but can burn ultra-low sulfur diesel (ULSD) for up to 1,440 hours per 12-month period. This permit requires the unit to comply with a limit of 895 lb CO_2/MWh-n even when burning up to 16 percent distillate oil. Each permit limit takes into account the mode of operation for the combustion turbine. For example, the permit for the Lower Colorado River Authority's Ferguson plant evaluated emission limits for the plant at 50, 75, and 100 percent gross load. The emission limit of 918 lb CO_2/MWh-n accounts for the unit's expected operation at 50 percent gross load. For NGCC units with duct burners on their HRSGs, the permit limits account for the hours of operation with duct burners firing. Finally, most of these permits include compliance margins to account for efficiency losses due to degradation and other factors (*e.g.,* actual operating parameters, site-specific design considerations, and the use of back up fuel). In total, these compliance margins result in a 10 to 13 percent increase in the permitted CO_2 emission limits, yet all of the limits except one were still below 1,000 lb CO_2/MWh-g.

Finally, we also reviewed NGCC design efficiency data and specifications submitted to *Gas Turbine World.* Specifically, we reviewed the reported efficiency data for 88 different 60 Hz NGCC units manufactured by Alstom, GE Energy Aeroderivative and Heavy Duty, Mitsubishi Heavy Industries, Pratt & Whitney, Rolls-Royce, and Siemens Energy. The designs ranged in model year from 1977 to 2011, capacities ranged from 31 to 1,026 MW, and base load ratings ranged from 236 to 3,551 MMBtu/h. The average reported design emission rate for these units was 834 lb CO_2/MWh-n and ranged from 725 to 941 lb CO_2/MWh-n. Therefore, our optional standard of 1,030 lb CO_2/MWh-n would allow for an average compliance margin of 24 percent, with a range from 10 to 42 percent, over the design rate. Ninety-five percent of designs would have a compliance margin of 13 percent or more, the top end of the range of compliance margins determined to be appropriate in the PSD permits we reviewed.

Because some commenters were concerned that smaller NGCC units will not be able to achieve the emission standard, we specifically considered the design rates for smaller units. For the 52 small units (base load rating of 850 MMBtu/h or less), the average design emission rate was 865 lb CO_2/MWh and ranged from 796 to 941 lb CO_2/MWh-n. Therefore, our optional standard of 1,030 lb CO_2/MWh-n would allow for an average compliance margin of 19 percent, with a range of 10 to 29 percent, over the design rate. Ninety-five percent of small NGCC designs would have a compliance margin of 13 percent or more.

We further refined our analysis by only considering the most efficient design for a given combustion turbine engine. For example, GE Energy Aeroderivative offers four design options for its LM2500 model-type, all with a rating of approximately 45 MW. The design emission rates for these various options range from 827 to 914 lb CO_2/MWh-n. When only the most efficient models for a particular combustion turbine engine design are considered, all NGCC models have over a 13 percent compliance margin. In other words, developers of new base load natural gas-fired combustion turbines concerned about the achievability of the final standard have multiple more efficient options offered by the same manufacturer. Therefore, we have concluded that the final emission standard allows sufficient flexibility for end users to select an

NGCC design appropriate for their specific requirements.

After considering these three sources of information—actual NGCC emission rate data, PSD permit limits for NGCC facilities, and NGCC design information—we have concluded that a standard of 1,000 lb CO_2/MWh is both achievable and appropriate for newly constructed base load natural gas-fired combustion turbines. While we anticipate that the large majority of new NGCC units will operate well below this emission rate, this standard provides flexibility for developers to take into account site-specific conditions (*e.g.,* ambient conditions and cooling system), operating characteristics (*e.g.,* part-load operation and frequent starting and stopping), and reduced efficiency due to degradation. The standard also accommodates the full size range of turbines.

We also expect multiple technology developments to further increase the performance of new base load natural gas-fired stationary combustion turbines. Vendors continue to improve the single cycle efficiency of combustion turbines. The use of more efficient combustion turbine engines improves the overall efficiency of NGCC facilities. In addition, existing smaller NGCC facilities were likely designed using single or dual pressure HRSGs without a reheat cycle. New designs can incorporate three pressure steam generators with a reheat cycle to improve the overall efficiency of the NGCC facility. Finally, additional technologies to reduce emission rates for new combustion turbines include CHP and integrated non-emitting technologies. For example, an NGCC unit that is designed as a CHP unit where ten percent of the overall output is useful thermal output would have an emission rate approximately five percent less than an electric-only NGCC. In sum, we believe that our final emission standards of 1,000 lb CO_2/MWh-g and 1,030 lb CO_2/MW-n are not only readily achievable, but likely conservative.

b. Reconstructed Base Load Natural Gas-Fired Units

We disagree with commenters that stated that reconstructed combustion turbines will not be able to achieve the proposed emission standards. For the reasons listed below, we have concluded that an existing base load natural-gas fired unit that reconstructs can achieve an emission rate of 1,000 lb CO_2/MWh-g, regardless of its size.

Highly efficient NGCC units include (1) an efficient combustion turbine engine, (2) an efficient steam cycle, and (3) a combustion turbine exhaust system that is ''matched'' to the steam cycle for maximum efficiency. In order for an existing NGCC unit to trigger the reconstruction provisions, the unit would have to essentially be entirely rebuilt. This would involve extensive upgrades to both the combustion turbine engine and the HRSG. Therefore, a reconstructed NGCC unit will be able to maximize the efficiency of the turbine engine and the steam cycle and match the two for maximum efficiency.

According to comments submitted in response to the proposal for existing sources under CAA section 111(d), there are various options available to improve the efficiency of existing combustion turbines. One combustion turbine manufacturer provided comments describing specific technology upgrades for the compressor, combustor, and gas turbine components. This manufacturer stated that operators of existing turbines can replace older internal components along the gas path with state-of-the-art components that have higher aerodynamic efficiencies and improved seal designs. These gas-path enhancements enable existing sources to both improve the efficiency of the turbine engine and improve the systems used for cooling the metal parts along the hot-gas path to allow existing systems to achieve higher operating temperatures. In total, the manufacturer stated that utilities deploying these gas-path improvements on reconstructed industrial frame combustion turbines with nominal output ratings of 170 to 180 MW can increase their output by 10 MW while reducing CO_2 emissions by more than 2.6 percent compared to baseline. In addition to gas-path and software improvements, the manufacturer stated that the newest low-NO_X combustor designs can be retrofitted on modified and reconstructed turbines to achieve lower NO_X emissions, which improves turndown (*i.e.,* to enable stable operations at lower loads compared to the lowest stable load achievable at baseline conditions) and efficiencies across all load conditions. The manufacturer indicated that operators of existing combustion turbines deploying both state-of-the-art gas-path and software upgrades and combustor upgrades can increase output on frame-style turbines with nominal output ratings of 170 to 180 MW by 14 MW, while reducing CO_2 emissions by 2.8 percent. In addition to the preceding upgrades, the manufacturer stated that existing combustion turbines can achieve the largest efficiency improvements by upgrading existing compressors with more advanced compressor technologies, potentially improving the combustion turbine's efficiency by an additional 3.8 percent. Thus, the total potential CO_2 emissions reductions for just the combustion turbine portion of a combined cycle unit is 6.6 percent.

In addition to upgrades to the combustion turbine engine, an operator reconstructing a NGCC unit will have the opportunity to improve the efficiency of the HRSG and steam cycle. For example, a steam turbine manufacturer identified three retrofit technologies available for reducing the CO_2 emissions rate of existing steam turbines by 1.5 to 3 percent: (1) Steam-path upgrades can minimize aerodynamic and steam leakage losses; (2) replacement of the existing high pressure turbine stages with state-of-the-art stages capable of extracting more energy from the same steam supply; and (3) replacement of low-pressure turbine stages with larger diameter components that extract additional energy and that reduce velocities, wear, and corrosion.

In addition, an operator reconstructing a NGCC unit could upgrade the entire steam cycle. For example, combined cycle units originally constructed with only a single pressure level can be upgraded to also include second and third pressure levels. Studies [538] [539] [540] show that converting a single pressure HRSG with steam reheat to a double pressure configuration with steam reheat can reduce the CO_2 emission rate of a NGCC unit by 1.5 to 1.7 percent. These same studies show that converting from a single pressure configuration with reheat to a triple pressure configuration with reheat can yield a 1.8 to 2 percent reduction in the CO_2 emission rate. Similarly, units constructed with only a double pressure configuration without reheat can obtain a 0.4 percent reduction by adding a reheat cycle or a 0.9 percent reduction by converting to a triple pressure configuration and adding a reheat cycle. Existing NGCC turbines that convert to these advanced HRSG configurations and that deploy the previously discussed combustion turbine and steam turbine upgrades can

[538] ''Exergetic and Economic Evaluation of the Effects of HRSG Configurations on the Performance of Combined Cycle Power Plants.'' M. Mansouri, *et al. Energy Conversion and Management* 58:47–58, 2012.

[539] ''Combined Cycle Power Plant Performance Analyses Based on Single-Pressure and Multipressure Heat Recovery Steam Generator.'' M. Rahim, *Journal of Energy Engineering,* 138:136–145, 2012.

[540] ''Thermodynamic Evaluation of Combined Cycle Plants.'' N. Woudstras *et al. Energy Conversion and Management* 51:1099–1110, 2010.

realize CO_2 emission rate reductions ranging from 6 to 10 percent, depending on their baseline design and condition. Based on the available options to improve the efficiency of existing NGCC units and the fact that the vast majority of existing NGCC units are already achieving emission rates of 1,000 lb CO_2/MWh-g or less, we have concluded that all reconstructed NGCC units can achieve this emission rate.

Finally, we note that an owner or operator that is considering reconstructing an existing simple cycle turbine should decide how they wish to operate that turbine in the future. If they anticipate operating above the percentage electric sales threshold, then they should install a HRSG and steam turbine and convert to a NGCC power block in accordance with our determination that NGCC is the BSER for base load applications. If they intend to operate the turbine below the percentage electric sales threshold, however, then the clean fuels standard, described below, will apply.

c. Newly Constructed and Reconstructed Non-Base Load Natural Gas-Fired Units

The EPA agrees with the commenters who stated that ''no emission limit'' would be inconsistent with the requirements of CAA 111(a)(1). We therefore are finalizing an input-based standard based on the use of clean fuels for non-base load natural gas-fired combustion turbines in recognition that efficiency can be reduced due to operation at low loads, cycling, and frequent startups. The EPA has concluded that, at this time, we do not have sufficient information to set a meaningful output-based standard for non-base load natural gas-fired combustion turbines. The input-based standard requires non-base load units to burn fuels with an average emission rate of 120 lb CO_2/MMBtu or less. This standard is readily achievable because the CO_2 emission rate of natural gas is 117 lb CO_2/MMBtu. The most common back up fuel is distillate oil, which has a CO_2 emission rate of 163 lb CO_2/MMBtu. A non-base load natural gas-fired combustion turbine burning 9 percent distillate oil and 91 percent natural gas has an emission rate of 121 lb CO_2/MMBtu, which rounds to 120 lb CO_2/MMBtu using two significant digits. Therefore, the vast majority of owners and operators of non-base load natural gas-fired combustion turbines will be able to achieve the standard using business-as-usual fuels.

While the emission reductions that will result from restricting the use of fuels with higher CO_2 emission rates is minor, the compliance burden is also minimal. Owners and operators of non-base load natural gas-fired combustion turbines burning fuels with consistent chemical compositions that meet the clean fuels requirement (*e.g.,* natural gas, ethane, ethylene, propane, naphtha, jet fuel kerosene, fuel oils No. 1 and 2, and biodiesel) will only need to maintain records that they burned these fuels in the combustion turbine. No additional recordkeeping or reporting will be required. Owners and operators burning fuels with higher CO_2 emission rates and/or chemical compositions that vary (*e.g.,* residual oil, non-jet fuel kerosene, landfill gas) will have to follow the procedures in part 98 of this part to determine the average CO_2 emission rate of the fuels burned during the applicable 12-operating-month compliance period and submit quarterly reports to verify that they are in compliance with the required emission standard.

d. Newly Constructed and Reconstructed Multi-Fuel-Fired Units

We also are finalizing an input-based standard based on the use of clean fuels, as opposed to an output-based standard, for multi-fuel units for several reasons. Specifically, we do not currently have continuous CO_2 emissions data for multi-fuel-fired units, we have not evaluated the potential efficiency impacts of different fuels, and the range of carbon content of non-natural gas fuels complicates establishing an appropriate output-based standard. Based on this lack of data, we have concluded that we cannot establish an output-based emission standard for multi-fuel-fired combustion turbines at this time.

The input-based emissions standard for this subcategory is based on the use of clean fuels. The use of clean fuels will ensure that newly constructed and reconstructed combustion turbines minimize CO_2 emissions during all periods of operation by limiting the use of fuels with higher CO_2 emission rates. To accurately represent the BSER and limit the ability of units to co-fire higher CO_2 emitting fuels with natural gas, we have concluded that it is necessary to use an equation based on the heat input from natural gas to determine the applicable emission standard. The 12-operating-month standard will vary from 120 lb CO_2/MMBtu to 160 lb CO_2/MMBtu depending on the fraction of heat input from natural gas. The standard will be calculated by adding the product of the percent of heat input from natural gas and 120 with the product of the heat input from non-natural gas fuels and 160. For example, a combustion turbine that burns 80 percent natural gas and 20 percent distillate oil would be subject to an emission standard of 130 lb CO_2/MMBtu (rounded to two significant figures), which is equivalent to the actual emission rate of a unit burning this combination of fuels. On the other hand, a combustion turbine that burns 100 percent residual oil would be subject to an emission standard of 160 lb CO_2/MMBtu, but would have a higher actual emission rate, and would thus be out of compliance. In this way, the standard will restrict higher carbon fuels from being burned in multi-fuel-fired units, but will be readily achievable by units burning clean fuels.

According to information submitted to the EIA, the primary, non-natural gas fuels used by combustion turbines today for the production of electricity should all meet our definition of a clean fuel. Thus, while the emission reductions that will result from restricting the use of fuels with higher CO_2 emission rates is minor, the compliance burden is also minimal. Owners and operators of multi-fuel-fired combustion turbines burning fuels with consistent chemical compositions that meet the clean fuels requirement (*e.g.,* natural gas, ethylene, propane, naphtha, jet fuel kerosene, fuel oils No. 1 and 2, and biodiesel) will only need to maintain records that they burned these fuels in the combustion turbine. No additional recordkeeping or reporting will be required. Owners and operators burning fuels with higher CO_2 emission rates and/or chemical compositions that vary (*e.g.,* residual oil, non-jet fuel kerosene, landfill gas) will have to follow the procedures in part 98 of this part to determine the average CO_2 emission rate of the fuels burned during the applicable 12-operating-month compliance period and submit quarterly reports to verify that they are in compliance with the required emission standard.

e. Modified Units

The EPA is not finalizing the proposed emission standards for stationary combustion turbines that conduct modifications. As explained in Section XV below, we are withdrawing the June 2014 proposal with respect to these sources. We received a significant number of comments asserting that modified combustion turbines could not meet the proposed emission standards of 1,000 lb/MWh-g for large turbines and 1,100 lb/MWh-g for small turbines. For the reasons explained in Section IX.B.1 above, we have decided not to subcategorize combustion turbines based on size for a number of reasons and are setting a single standard of

1,000 lb/MWh-g for all base load natural gas-fired turbines instead. While we are confident that all new and reconstructed units will be able to achieve this standard, we are less confident that all smaller combustion turbines that undertake a modification, specifically those that were constructed prior to 2000, will be able to do so. Until we have the opportunity to further investigate the full range of modifications that turbine owners and operators might undertake, we consider it premature to finalize emission standards for these sources.

Combustion turbines have unique characteristics that make determining an appropriate emission standard for modified sources a more challenging task than for coal-fired boilers. For example, each combustion turbine engine has a specific corresponding combustor. The development of more efficient combustor upgrades for existing turbine designs typically requires manufacturers to expend considerable resources. Consequently, not all manufacturers offer combustor upgrades for smaller or older designs because it would be difficult to recoup their investment. In contrast, efficiency upgrades for boilers can generally be installed regardless of the specific boiler's characteristics.

In addition, natural gas has the lowest CO_2 emission rate (in terms of lb CO_2/MMBtu) of any fossil fuel. As a result, an owner or operator that adds the ability to burn a back up fuel, such as distillate oil, to an existing turbine would likely trigger an NSPS modification. This is a relatively low-capital-cost upgrade that would significantly increase a unit's potential hourly emission rate, even though the annual emissions increase would be relatively minor because operating permits generally limit the amount of distillate oil that a unit can burn. We need to conduct additional analysis to determine an appropriate emission standard for units that undertake this type of modification, which does not involve any of the combustion turbine components that impact efficiency.

To be clear, the EPA is not reaching a final decision that modifications should be subject to different requirements than we are finalizing in this rule for new and reconstructed sources. We have made no decisions, and this matter is not concluded. We plan to continue to gather information, consider the options for modifications, and develop a new proposal for modifications in the future. Therefore, the EPA is withdrawing the proposed standards for all combustion turbines that conduct modifications and is not issuing final standards for those sources at this time. See Section XV below. We note that the effect of this withdrawal is that modified combustion turbines will continue to be existing sources subject to section 111(d).[541]

X. Summary of Other Final Requirements for Newly Constructed, Modified, and Reconstructed Fossil Fuel-Fired Electric Utility Steam Generating Units and Stationary Combustion Turbines

This section describes the final action's requirements regarding startup, shutdown, and malfunction; continuous monitoring; emissions performance testing; continuous compliance; and notification, recordkeeping, and reporting for newly constructed, modified, and reconstructed affected steam generating units and combustion turbines. We also explain final decisions regarding several of these requirements.

A. Startup, Shutdown, and Malfunction Requirements

In its 2008 decision in *Sierra Club* v. *EPA,* 551 F.3d 1019 (D.C. Cir. 2008), the D.C. Circuit vacated portions of two provisions in the EPA's CAA section 112 regulations governing the emissions of hazardous air pollutants (HAP) during periods of startup, shutdown, and malfunction (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 CAA section 112 standards apply continuously.

Consistent with *Sierra Club* v. *EPA,* the EPA has established standards in this rule that apply at all times. In establishing the standards in this rule, the EPA has taken into account startup and shutdown periods and, for the reasons explained below as well as in Section V.J.1 above, has not established alternate standards for those periods. Specifically, startup and shutdown periods are included in the compliance calculation as periods of partial load. The final method to calculate compliance is to sum the emissions for all operating hours and to divide that value by the sum of the electric energy output (and useful thermal energy output, where applicable for affected CHP EGUs), over a rolling 12-operating-month period. In their compliance determinations, sources must incorporate emissions from all periods, including startup or shutdown, during which fuel is combusted and emissions are being monitored, in addition to all power produced over the periods of emissions measurements. As explained in Section V.J.1, given that the duration of startup or shutdown periods is expected to be small relative to the duration of periods of normal operation and that the fraction of power generated during periods of startup or shutdown is expected to be very small, the impact of these periods on the total average over a 12-operating-month period is expected to be minimal.

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 60.2). The EPA interprets CAA section 111 as not requiring emissions that occur during periods of malfunction to be factored into development of section 111 standards. Nothing in CAA section 111 or in case law requires that the EPA consider malfunctions when determining what standards of performance reflect the degree of emission limitation achievable through ''the application of the best system of emission reduction'' that the EPA determines is adequately demonstrated. While the EPA accounts for variability in setting emissions standards, nothing in CAA section 111 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 111 standards of performance.

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

[541] As discussed above in Section VI.A of this preamble, a modified source that is not covered by a final or pending proposed standard continues to be an ''existing source'' and so will be covered by requirements under section 111(d). Under the definition of ''existing source'' in section 111(a)(6), an existing source is any source that is not a new source. Under the definition of ''new source'' in section 111(a)(2), a modified source is a new source only if the modification occurs after the publication of regulations (or proposed regulations, if earlier) that will be applicable to that source. Because we are not finalizing regulations with respect to modified steam turbines, and are withdrawing the proposal with respect to such sources, there are neither final regulations nor pending proposed regulations which will be applicable to such modifications.

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 shut down, 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 111 to avoid such a result. The EPA's approach to malfunctions is consistent with CAA section 111 and is a reasonable interpretation of the statute.

Given that compliance with the emission standard is determined on a 12-operating-month rolling average basis, the impact of periods of malfunctions on the total average over a 12-operating-month period is expected to be minimal. Thus, malfunctions over that period are not likely to result in a violation of the standard.

In the unlikely event that a source fails to comply with the applicable CAA section 111 standards as a result of a malfunction event, the EPA would determine an appropriate response based on, among other things, the good faith efforts of the source to minimize emissions during malfunction periods, including preventative and corrective actions, as well as root cause analyses to ascertain and rectify excess emissions. The EPA would also consider whether the source's failure to comply with the CAA section 111 standard was, in fact, sudden, infrequent, not reasonably preventable and was not instead caused in part by poor maintenance or careless operation. 40 CFR 60.2 (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 111 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 January 2014 proposal for newly constructed EGUs, the EPA had proposed to include an affirmative defense to civil penalties for violations caused by malfunctions in an effort to create a system that incorporates some flexibility, recognizing that there is a tension, inherent in many types of air regulation, to ensure adequate compliance while simultaneously recognizing that despite the most diligent of efforts, emission standards may be violated under circumstances entirely beyond the control of the source. Although the EPA recognized that its case-by-case enforcement discretion provides sufficient flexibility in these circumstances, it included 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 EPA's 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. Recently, the U.S. 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.'').[542] In light of *NRDC,* the EPA is not including a regulatory affirmative defense provision in this 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 violations 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.[543]

[542] 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.*

[543] 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. Moreover, assessment of penalties for violations caused by malfunctions in administrative

Continued

B. Continuous Monitoring Requirements

The majority of comments received on the proposal supported the EPA's use of existing monitoring requirements under the Acid Rain Program, which are contained in 40 CFR part 75 requirements. In response to this, the EPA is finalizing monitoring requirements that incorporate and reference the part 75 monitoring requirements for the majority of the CO_2 and energy output monitoring requirements while ensuring accuracy and stringency required under the program.

This final rule requires owners or operators of EGUs that combust solid fossil fuel to install, certify, maintain, and operate continuous emission monitoring systems (CEMS) to measure CO_2 concentration, stack gas flow rate, and (if needed) stack gas moisture content in accordance with 40 CFR part 75, in order to determine hourly CO_2 mass emissions rates (tons/hr).

The rule allows owners or operators of affected EGUs that burn exclusively gaseous or liquid fuels to install fuel flow meters as an alternative to CEMS and to calculate the hourly CO_2 mass emissions rates using Equation G–4 in appendix G of part 75. To implement this option, hourly measurements of fuel flow rate and periodic determinations of the gross calorific value (GCV) of the fuel are also required, in accordance with appendix D of part 75.

In addition to requiring monitoring of the CO_2 mass emission rate, the rule requires EGU owners or operators to monitor the hourly unit operating time and ''gross output'', expressed in megawatt hours (MWh). The gross output includes electrical output plus any mechanical output, plus 75 percent of any useful thermal output.

The rule requires EGU owners or operators to prepare and submit a monitoring plan that includes both electronic and hard copy components, in accordance with 40 CFR 75.53(g) and (h). The electronic portion of the monitoring plan should be submitted to the EPA's CAMD using the Emissions Collection and Monitoring Plan System (ECMPS) Client Tool. The hard copy portion of the plan should be sent to the applicable state and EPA Regional office. Further, all monitoring systems used to determine the CO_2 mass emission rates have to be certified according to 40 CFR 75.20 and section 6 of part 75, appendix A within the 180-day window of time allotted under 40 CFR 75.4(b), and are required to meet the applicable on-going quality assurance procedures in appendices B and D of part 75.

The rule requires all valid data collected and recorded by the monitoring systems (including data recorded during startup, shutdown, and malfunction) to be used in assessing compliance. Failure to collect and record required data is a violation of the monitoring requirements, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities that temporarily interrupt the measurement of stack emissions (*e.g.,* calibration error tests, linearity checks, and required zero and span adjustments).

The rule requires only those operating hours in which valid data are collected and recorded for all of the parameters in the CO_2 mass emission rate equation to be used for calculating compliance with applicable emission limits. Additionally for EGUs using CO_2 CEMS, only unadjusted stack gas flow rate values should be used in the emissions calculations. In this rule, part 75 bias adjustment factors (BAFs) should not be applied to the flow rate data. These restrictions on the use of part 75 data for part 60 compliance are consistent with previous NSPS regulations and revisions. Additionally if an affected EGU combusts natural gas and/or fuel oil and the CO_2 mass emissions rate are measured using Equation G–4 in appendix G of part 75, then determination of site-specific carbon-based F-factors using Equation F–7b in section 3.3.6 of appendix F of part 75 is allowed, and use of these F_c values in the emissions calculations instead of using the default F_c values in the Equation G–4 nomenclature is also allowed.

This final rule includes the following special compliance provisions for units with common stack or multiple stack configurations; these provisions are consistent with 40 CFR 60.13(g):

- If two or more EGUs share a common exhaust stack, are subject to the same emission limit, and the operator is required to (or elects to) determine compliance using CEMS, then monitoring the hourly CO_2 mass emission rate at the common stack instead of monitoring each EGU separately is allowed. If this option is chosen, the hourly gross electrical load (or steam load) is the sum of the hourly loads for the individual EGUs and the operating time is expressed as ''stack operating hours'' (as defined in 40 CFR 72.2). Then, if compliance with the applicable emission limit is attained at the common stack, each EGU sharing the stack will be in compliance with the CO_2 emissions limit.
- If the operator is required to (or elects to) determine compliance using CEMS and the effluent from the EGU discharges to the atmosphere through multiple stacks (or, if the effluent is fed to a stack through multiple ducts and is monitored in the ducts), then monitoring the hourly CO_2 mass emission rate and the ''stack operating time'' at each stack or duct separately is required. In this case, compliance with the applicable emission limit is determined by summing the CO_2 mass emissions measured at the individual stacks or ducts and dividing by the total gross output for the unit.

The rule requires 95 percent of the operating hours in each compliance period (including the compliance periods for the intermediate emission limits) to be valid hours, *i.e.,* operating hours in which quality-assured data are collected and recorded for all of the parameters used to calculate CO_2 mass emissions. EGU owners or operators have the option to use back up monitoring systems, as provided in 40 CFR 75.10(e) and 75.20(d), to help meet this data capture requirement. This requirement is separate from the requirement for a source to demonstrate compliance with an applicable emission standard. When demonstrating compliance with an emission standard the calculation must use all valid data to calculate a compliance average even if the percent of valid hours recorded in the period is less than the 95 percent requirement.

C. Emissions Performance Testing Requirements

Similarly to the comments received on monitoring for the proposal, commenters in general supported the use of current testing requirements required under the Acid Rain Program 40 CFR part 75 requirements. Thus the EPA is finalizing requirements for performance testing as consistent with part 75 requirements where appropriate to ensure the quality and accuracy of data and measurements as required by the final rule.

In accordance with 40 CFR 75.64(a), the final rule requires an EGU owner or operator to begin reporting emissions data when monitoring system certification is completed or when the 180-day window in 40 CFR 75.4(b) allotted for initial certification of the monitoring systems expires (whichever date is earlier). For EGUs subject to the

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).

1,400 lb CO_2/MWh-g) emission standard, the initial performance test consists of the first 12 operating months of data, starting with the month in which emissions are first required to be reported. The initial 12-operating-month compliance period begins with the first month of the first calendar year of EGU operation in which the facility exceeds the capacity factor applicability threshold.

The traditional 3-run performance tests (*i.e.,* stack tests) described in 40 CFR 60.8 are not required for this rule. Following the initial compliance determination, the emission standard is met on a 12-operating-month rolling average basis.

D. Continuous Compliance Requirements

Commenters supported the use of a 12-operating-month rolling average for the compliance period for the final standards. In response, this final rule specifies that compliance with the 1,400 lb CO_2/MWh-g emission limit is determined on a 12-operating-month rolling average basis, updated after each new operating month. For each 12-operating-month compliance period, quality-assured data from the certified Part 75 monitoring systems is used together with the gross output over that period of time to calculate the average CO_2 mass emissions rate.

The rule specifies that the first operating month included in the initial 12-operating-month compliance period is the month in which reporting of emissions data is required to begin under 40 CFR 75.64(a), *i.e.,* either the month in which monitoring system certification is completed or the month in which the 180-day window allotted to finish certification testing expires (whichever month is earlier).

Initial compliance with the applicable emissions limit in kg/MWh is calculated by dividing the sum of the hourly CO_2 mass emissions values by the total gross output for the 12-operating-month period. Affected EGUs continue to be subject to the standards and maintenance requirements in the CAA section 111 regulatory general provisions contained in 40 CFR part 60, subpart A.

Several commenters stated that the final rule should require operators to round their calculated emissions rates to three significant figures when comparing their actual rates to the standard. These commenters said that allowing use of only two significant digits when calculating the 12-operating-month rolling average emission rate would constitute relaxation of the standard by 5 percent because an actual emission rate of 1,049.9 lb CO_2/MWh rounds to 1,000 lb of CO_2 per MWh when only two significant figures are required in the final step of compliance calculations. Commenters also suggested that the emission limits be written in scientific notation (*e.g.,* 1.10 x 10 − 3 lb CO_2/MWh) to clarify the number of significant digits that should be used when evaluating compliance. Other commenters suggested that the final step in compliance calculations should reflect rounding the emission rate to the nearest whole number using the ASTM rounding convention (ASTM E29).

The General Provisions of Part 60 specify the rounding conventions for compliance calculations at 40 CFR 60.13(h)(3) including the provision that ''after conversion into units of the standard, the data may be rounded to the same number of significant digits used in the applicable subpart to specify the emission limit.''

The final rule requires that the 12-operating-month rolling average emission rate must be rounded to three significant figures if the applicable emissions standard is greater than or equal to 1,000 (*e.g.,* an actual emission rate of 1,004.9 lb CO_2/MWh is rounded to 1,000 lb CO_2/MWh); for standards of 1000 or less, the final rule requires rounding the actual emission rate to two significant figures (*e.g.,* an actual emission rate of 454.9 kg CO_2/MWh is rounded to 450 kg CO_2/MWh). Historically, many of the emissions limits under part 60 have been expressed to two significant digits (*e.g.,* the original SO_2 emission standard for coal-fired units under Subpart D was 1.2 lb SO_2/MMBtu). The rounding conventions under the General Provisions allow the reporting of all emission rates in the range from 1.15 to 1.249 as 1.2 lb SO_2/MMBtu. During compliance periods with emissions at the lower end of this range, the operator is required to report higher emissions than actually occurred; during compliance periods at the upper end of this range the operator is allowed to report lower emissions than actually occurred. In either case the absolute error remains small because the emission rate in this example is a relatively small numerical value. In addition, the required emission reductions typically are large enough that rounding does not impact the emission control strategy of affected units. However, the final standards for CO_2 emissions include numerical values that are larger than many historical emissions standards and require a relatively small percent reduction in emissions. Accordingly, it is appropriate to require the use of three significant digits when completing compliance calculations resulting in numerical values larger than 1,000. This is particularly important when considering the relatively small emission rate changes that may be required for compliance with the unit-specific emission standards being finalized for modified steam generating and IGCC units because a rounding error of 5 percent may be larger than the percent difference between the affected unit's historically best emission rate and the emission rate immediately preceding the modification.

The final rule requires rounding of emission rates with numerical values greater than or equal to 1,000 to three significant figures and rounding of rates with numerical values less than 1,000 to two significant figures.

E. Notification, Recordkeeping, and Reporting Requirements

Commenters supported the coordination of notification, recordkeeping, and reporting required under this rule in conjunction with the requirements already in place under part 75, so the EPA has made the requirements as efficient and streamlined as possible with the current requirements under part 75. The final rule requires an EGU owner or operator to comply with the applicable notification requirements in 40 CFR 75.61, 40 CFR 60.7(a)(1) and (a)(3), and 40 CFR 60.19. The rule also requires the applicable recordkeeping requirements in subpart F of part 75 to be met. For EGUs using CEMS, the data elements that are recorded include, among others, hourly CO_2 concentration, stack gas flow rate, stack gas moisture content (if needed), unit operating time, and gross electric generation. For EGUs that exclusively combust liquid and/or gaseous fuel(s) and elect to determine CO_2 emissions using Equation G–4 in appendix G of part 75, the key data elements in subpart F that are recorded include hourly fuel flow rates, fuel usage times, fuel GCV, gross electric generation.

The rule requires EGU owners or operators to keep records of the calculations they perform to determine the total CO_2 mass emissions and gross output for each operating month. Records of the calculations performed to determine the average CO_2 mass emission rate (kg/MWh) and the percentage of valid CO_2 mass emission rates in each compliance period are required to be kept. The rule also requires sources to keep records of calculations performed to determine site-specific carbon-based F-factors for use in Equation G–4 of part 75, appendix G (if applicable).

Sources are required to keep all records for a period of 3 years. All required records must be kept on-site for a minimum of two years, after which the records can be maintained off-site.

The rule requires all affected EGU owners/operators to submit quarterly electronic emissions reports in accordance with subpart G of part 75. The reports in appendix G that do not include data required to calculate compliance with the applicable CO_2 emission standard are not required to be reported under this rule. The rule requires the reports in 40 CFR 60.5555 to be submitted using the ECMPS Client Tool. Except for a few EGUs that may be exempt from the Acid Rain Program (*e.g.,* oil-fired units), this is not a new reporting requirement. Sources subject to the Acid Rain Program are already required to report the hourly CO_2 mass emission rates that are needed to assess compliance with this rule.

Additionally, in the final rule and as part of an agency-wide effort to streamline and facilitate the reporting of environmental data, the rule requires selected data elements that pertain to compliance under this rule, and that serve the purpose of identifying violations of an emission standard, to be reported periodically using ECMPS.

Specifically, EGU owners/operators must submit quarterly electronic reports within 30 days after the end of each quarter consistent with current part 75 reporting requirements. The first report is for the quarter that includes the final (12th) operating month of the initial 12-operating-month compliance period. For that initial report and any subsequent report in which the 12th operating month of a compliance period (or periods) occurs during the calendar quarter, the average CO_2 mass emissions rate (kg/MWh) is reported for each compliance period, along with the dates (year and month) of the first and twelfth operating months in the compliance period and the percentage of valid CO_2 mass emission rates obtained in the compliance period. The dates of the first and last operating months in the compliance period clearly bracket the period used in the determination, which facilitates auditing of the data. Reporting the percentage of valid CO_2 mass emission rates is necessary to demonstrate compliance with the requirement to obtain valid data for 95 percent of the operating hours in each compliance period. Any violations that occur during the quarter are identified. If there are no compliance periods that end in the quarter, a definitive statement to that effect must be included in the report. If one or more compliance periods end in the quarter but there are no violations, a statement to that effect must be included in the report.

Currently, ECMPS is not programmed to receive the additional information included in the report required under 40 CFR 60.5555(a)(2) for affected EGUs. However, we will make the necessary modifications to the system in order to fully implement the reporting requirements of this rule upon promulgation.

XI. Consistency Between BSER Determinations for This Rule and the Rule for Existing EGUs

In the CAA section 111(d) rule for existing steam units and combustion turbines that the EPA is promulgating at the same time as this CAA section 111(b) rule, the EPA is identifying as part of the BSER for those sources, building block 1 (for steam units, efficient operation), building block 2 (for steam units, dispatch shift to existing NGCC units), and building block 3 (for steam units and combustion turbines, substitution of generation with new renewable energy). In this section, we explain why the EPA is not identifying building blocks 1, 2, or 3 as part of the BSER for new, modified, or reconstructed steam generators or combustion turbines.

A. Newly Constructed Steam Generating Units

1. Preference for Technological Controls as the BSER for New EGUs

As discussed in this preamble and in more detail in the preamble to the CAA section 111(d) rule for existing sources, the phrase ''system of emission reduction'' is undefined and provides the EPA with discretion in setting a standard of performance under CAA section 111(b) or emission guidelines under CAA section 111(d). Because the phrase by its plain language does not limit our review of potential systems in either context, the same systems could be considered for application in new and existing sources. That said, many other factors and considerations direct us to focus on different systems when establishing a standard of performance under CAA section 111(b) and an emission guideline under CAA section 111(d). Thus, it is useful to describe part of the underlying basis for the BSER—partial CCS—that the EPA has determined for new steam units before discussing the building blocks that form the BSER for existing units.

For new steam generating units, the EPA is identifying, as the BSER, systems of emission reduction that assure that these sources are inherently low-emitting at the time of construction. The following reasons support this approach to the BSER.

New sources are expected to have long operating lives over which initial capital costs can be amortized. Thus, new construction is the preferred time to drive capital investment in emission controls. In this case, the BSER for new steam generators, partial CCS, requires substantial capital expenditures, which new sources are best able to accommodate.

While CAA section 111(b)(1)(B) and (a)(1) by their terms do not mandate that the BSER assure that new sources are inherently low emitting, that approach to the BSER is consistent with the legislative history.[544] See Section III.H.3.b.4 above. For instance, the 1970 Senate Committee Report explains that ''[t]he overriding purpose of this section [concerning new source performance standards] 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.'' [545] Existing sources, on the other hand, would be regulated through emission standards, which were broadly understood at the time to reflect available technology, alternative methods of prevention and control, alternative fuels, processes, and operating methods.[546] [547]

[544] Although Congress expressed a clear preference that new sources would be ''designed, built, equipped, operated, and maintained so as to reduce emissions to a minimum,'' the Senate Committee Report also makes clear that the term standard of performance ''refers to the degree of emission control which can be achieved through process changes, operation changes, direct emission control, *or other methods.''* Sen. Rep. No. 91–1196 at 15–17, 1970 CAA Legis. Hist. at 415–17 (emphasis added).

[545] Sen. Rep. No. 91–1196 at 15–16, 1970 CAA Legis. Hist. at 416 (emphasis added).

[546] *See* 1970 CAA Amendments, Pub. L. 91–604, section 4, 84 Stat. 1676, 1679 (Dec. 31, 1970) (describing information that the EPA must issue to the states and appropriate air pollution control agencies along with the issuance of ambient air quality criteria under Section 4 of the 1970 CAA titled ''Ambient Air Quality and Emission Standards'').

[547] In the 1977 CAA Amendments, Congress revised section 111(a)(1) to mandate that the EPA base standards for new sources on technological controls, but, at the same time, made clear that the EPA was not required to base the emission guidelines for existing sources on technological controls. In the 1990 CAA Amendments, Congress repealed the section 111(a)(1) requirements that distinguished between new and existing sources and largely restored the 1970 CAA Amendments version of section 111(a)(1).

2. Practical Implications of Including the Building Blocks

Several practical considerations make the building blocks inappropriate for new sources. Thus, for the following reasons, the EPA does not consider it appropriate to include the building blocks as part of the BSER for new sources:

a. Additional Cost

Partial CCS will impose substantial (albeit reasonable) costs on new steam-generating EGUs, and, as a result, the EPA does not believe that including additional measures as part of the BSER would be appropriate. One disadvantage in adding additional costs is that doing so would make it more difficult for new steam-generating EGUs to compete with new nuclear units. Because the BSER is selected after considering cost (among other factors), the EPA is not required to,[548] and in this case believes it would not be appropriate to, select the most stringent adequately demonstrated system of emission reduction (through the combination of partial CCS and the building blocks) for purposes of setting a standard of performance under CAA section 111(b).

Building block 1 measures are not appropriate (or would be redundant) because the BSER for new steam generating units is based on highly efficient supercritical technology, *i.e.,* state-of-the-art, efficient equipment. See Section V.K above. Accordingly, there is little improvement in efficiency that can be justified as part of the BSER.

Building block 2 and 3 measures are not appropriate for the BSER because new steam units would have a significantly limited range of options to implement building blocks 2 and 3. The new source performance standard was proposed and is being finalized as a rate-based standard. Thus, if building blocks 2 and 3 were included in the BSER, a more stringent rate-based standard would be applicable to all new sources. However, it is conceivable that the EPA could propose a hybrid standard that would include both an emission-rate limit that reflects partial CCS and a requirement for allowances that reflects building blocks 2 and 3. Accordingly, the following discussion assumes either a rate-based or mass-based standard, or part of a hybrid standard.

In both a rate-based program and a mass-based program, building blocks 2 and 3 measures can be implemented through a range of methods, including trading with other EGUs. While it is not necessarily the case that every existing source will be able to implement each of the methods, in general, existing sources will have a range of measures to choose from. However, at least some of those methods may not be available to new sources, which would render compliance with their emission limits more challenging and potentially more costly.

One example is emission trading with other affected EGUs. For existing sources, emission trading is an important option for implementing the building blocks. There are large numbers of existing sources, and they will become subject to the section 111(d) standards of performance at the same time. It may be more cost-effective for some to implement the building blocks than others, and, as a result, some may over-comply and some may under-comply, and the two groups may trade with each other. Because of the large numbers of existing sources, the trading market can be expected to be robust. Trading optimizes efficiency. As a result, existing sources have more flexibility in the overall amount of their investment in building blocks 2 and 3 and can adjust investment obligations among themselves through emissions trading.

In contrast, new sources construct one at a time, and it is unknown how many new sources there will be. Without a sizeable number of new sources, there will not be a robust trading market. Thus, a new source cannot count on being able to find a new source trading partner. In addition, it is not possible to count on new sources being able to trade with existing sources, for several reasons. First, as noted, there are indications in the legislative history that new sources should be well-controlled at the source, which casts doubt on whether new sources should be allowed to meet their standards through the purchase of emission credits. Second, new sources must meet their standards of performance as soon as they begin operations. If they do so before the year 2022, when existing sources become subject to section 111(d) state plan standards of performance, no existing sources will be available as trading partners.

In addition, for section 111(d) sources, we are granting a 7-year period of lead-time for the implementation of the building blocks. This is due, in part, to the benefits of allowing the ERC and allowance markets to develop. However, the new source standards take effect immediately, so new sources would not have the advantage of this lead time were they subject to more stringent standards that also reflected the building blocks.[549]

In addition, if there are an unexpectedly large number of new sources, then they would be obliged to invest in greater amounts of building blocks 2 and 3, and that could reduce the amounts of building blocks 2 and 3 available for existing sources, and thereby raise the costs of building blocks 2 and 3 for existing sources. This could compromise the BSER under section 111(d) and undermine the ability of existing sources to comply with their section 111(d) obligations.[550]

B. New Combustion Turbines

For new combustion turbines, the building blocks are not appropriate as part of the BSER either. Building block 1 is limited to steam generating units, and therefore has no applicability to new combustion turbines. Measures comparable to those in building block 1 would not be appropriate because new highly efficient NGCC construction already entails high efficiency equipment and operation. Building block 2 is also limited to steam generating units and is not appropriate as part of the BSER for new NGCC units because it would not result in any emission reductions.

The reasons why building block 3 are not appropriate are the same as discussed above for why building blocks 2 and 3 are not appropriate for new steam generating units (limited range of options for implementation (including lack of availability of trading), lack of

[548] For example, as early as a 1979 NSPS rulemaking for affected EGUs, the EPA recognized that it was not required to establish as the BSER the most stringent adequately demonstrated system of emission reduction available, and instead could weigh the amount of additional emission reductions against the costs. *See* 44 FR 52792, 52798 (Sept. 10, 1979) (''Although there may be emission control technology available that can reduce emissions below those levels required to comply with standards of performance, this technology might not be selected as the basis of standards of performance due to costs associated with its use. Accordingly, standards of performance should not be viewed as the ultimate in achievable emission control. In fact, the Act requires (or has potential for requiring) the imposition of a more stringent emission standard in several situations.'').

[549] At least in theory, we could consider promulgating a standard of performance for new affected EGUs that becomes more stringent beginning in 7 years, based on a more stringent BSER. We are not inclined to adopt that approach because section 111(b)(1)(B) requires that we review and, if necessary, revise the section 111(b) standards of performance no later than every 8 years anyway.

[550] The EPA is authorized to consider the BSER for new and existing sources in conjunction with each other. In the 1977 CAA Amendments, Congress revised section 111(a)(1) to require technological controls for new combustion sources at least in part because this requirement would preclude new sources from relying on low-sulfur coal to achieve their emission limits, which, in turn, would free up low-sulfur coal for existing sources.

lead-time for implementation, and the possibility of reducing the availability of renewable energy for existing sources).

C. Modified and Reconstructed Steam and NGCC Units

For modified and reconstructed steam generators, the EPA identified the BSER as maintenance of high efficiency or implementation of a highly efficient unit. The resulting emission limit must be met over the specified time period and cannot be deviated from or averaged. As a result, a modified or reconstructed steam generator generally will require ongoing maintenance and may find it prudent to operate below its limit as a safety margin. This represents a substantial commitment of resources. For these units, the additional costs of implementing the building blocks would not be appropriate.

In addition, building block 1 is not appropriate for modified or reconstructed steam generating units because the BSER for these units is already based on highly efficient performance. For the same reasons, it does not make sense to attempt to develop the analogue to building block 1 for reconstructed NGCC units—the BSER for them, too, is already based on highly efficient performance.

Building block 2 is not appropriate for reconstructed NGCC units because it would not yield any reductions.

Building blocks 2 and 3 are not appropriate for modified or reconstructed steam generators, and building block 3 is not appropriate for reconstructed NGCC units, for the same reasons that they are not appropriate for new EGUs, as described above (limited range of options for implementation (including lack of availability of trading), lack of lead-time for implementation, and the possibility of reducing the availability of renewable energy for existing sources).

XII. Interactions With Other EPA Programs and Rules

A. Overview

This final rule will, for the first time, regulate GHGs under CAA section 111. In Section IX of the preamble to the proposed rule, the EPA addressed how regulation of GHGs under CAA section 111 could have implications for other EPA rules and for permits written under the CAA Prevention of Significant Deterioration (PSD) preconstruction permit program and the CAA Title V operating permit program. The EPA proposed to adopt provisions in the regulations that explicitly addressed some of these implications.

For purpose of the PSD program, the EPA is finalizing provisions in part 60 of its regulations that make clear that the threshold for determining whether a PSD source must satisfy the BACT requirement for GHGs continues to apply after promulgation of this rule. This rule does not require any additional revisions to State Implementation Plans. As discussed further below, this final rule may have bearing on the determination of BACT for new, modified, and reconstructed EGUs that require PSD permits. With respect to the Title V operating permits program, this rule does not affect whether sources are subject to the requirement to obtain a Title V operating permit based solely on emitting or having the potential to emit GHGs above major source thresholds. However, this rule does have some implications for Title V fees, which the EPA is addressing in this final rule.

Finally, the fossil fuel-fired EGUs covered in this rule are or will be potentially impacted by several other recently finalized or proposed EPA rules, and such potential interactions with other EPA rules are discussed below.

B. Applicability of Tailoring Rule Thresholds Under the PSD Program

In our January 8, 2014 proposal, the EPA proposed to adopt regulatory language in 40 CFR part 60 that would ensure the promulgation of this NSPS would not undercut the application of rules that limit the application of the PSD permitting program requirements to only the largest sources of GHGs. An intervening decision of the United States Supreme Court has, to a large extent, resolved the legal issue that led the EPA to propose these part 60 provisions. The Supreme Court has since clarified that the PSD program does not apply to smaller sources based on the amount of GHGs they emit. However, because the largest sources emitting GHGs remain subject to the PSD permitting requirements, the EPA has concluded that it remains appropriate to adopt the proposed regulatory provisions in 40 CFR part 60 in this rule. We discuss our reasons for this action in detail below.

Under the PSD program in part C of title I of the CAA, in areas that are classified as attainment or unclassifiable for NAAQS pollutants, a new or modified source that emits any air pollutant subject to regulation at or above specified thresholds is required to obtain a preconstruction permit. This permit assures that the source meets specific requirements, including application of BACT to each pollutant subject to regulation under the CAA. Many states (and local districts) are authorized by the EPA to administer the PSD program and to issue PSD permits. If a state is not authorized, then the EPA issues the PSD permits for facilities in that state.

To identify the pollutants subject to the PSD permitting program, EPA regulations contain a definition of the term ''regulated NSR pollutant.'' 40 CFR 52.21(b)(50); 40 CFR 51.166(b)(49). This definition contains four subparts, which cover pollutants regulated under various parts of the CAA. The second subpart covers pollutants regulated under section 111 of the CAA. The fourth subpart is a catch-all provision that applies to ''[a]ny pollutant that is otherwise subjection to regulation under the Act.''

This definition and the associated PSD permitting requirements applied to GHGs for the first time on January 2, 2011, by virtue of the EPA's regulation of GHG emissions from motor vehicles, which first took effect on that same date. 75 FR 17004 (Apr. 2, 2010). As such, GHGs became subject to regulation under the CAA and the fourth subpart of the ''regulated NSR pollutant'' definition became applicable to GHGs.

On June 3, 2010, the EPA issued a final rule, known as the Tailoring Rule, which phased in permitting requirements for GHG emissions from stationary sources under the CAA PSD and Title V permitting programs (75 FR 31514). Under its understanding of the CAA at the time, the EPA believed the Tailoring Rule was necessary to avoid a sudden and unmanageable increase in the number of sources that would be required to obtain PSD and Title V permits under the CAA because the sources emitted GHGs emissions over applicable major source and major modification thresholds. In Step 1 of the Tailoring Rule, which began on January 2, 2011, the EPA limited application of PSD or Title V requirements to sources of GHG emissions only if the sources were subject to PSD or Title V ''anyway'' due to their emissions of non-GHG pollutants. These sources are referred to as ''anyway sources.'' In Step 2 of the Tailoring Rule, which began on July 1, 2011, the EPA applied the PSD and Title V permitting requirements under the CAA to sources that were classified as major, and, thus, required to obtain a permit, based solely on their potential GHG emissions and to modifications of otherwise major sources that required a PSD permit because they increased only GHG emissions above applicable levels in the EPA regulations.

In the PSD program, the EPA implemented the steps of the Tailoring Rule by adopting a definition of the term ''subject to regulation.'' The limitations in Step 1 of the Tailoring Rule are reflected in 40 CFR 52.21(b)(49)(iv) and 40 CFR 51.166(b)(48)(iv). With respect to ''anyway sources'' covered by PSD during Step 1, this provision established that GHGs would not be subject to PSD requirements unless the source emitted GHGs in the amount of 75,000 tons per year (tpy) of carbon dioxide equivalent (CO_2e) or more. The primary practical effect of this paragraph is that the PSD BACT requirement does not apply to GHG emissions from an ''anyway source'' unless the source emits GHGs at or above this threshold. The Tailoring Rule Step 2 limitations are reflected in 40 CFR 52.21(b)(49)(v) and 51.166(b)(48)(v). These provisions contain thresholds that, when applied through the definition of ''regulated NSR pollutant,'' function to limit the scope of the terms ''major stationary source'' and ''major modification'' that determine whether a source is required to obtain a PSD permit. See *e.g.* 40 CFR 51.166(a)(7)(i) and (iii); 40 CFR 51.166(b)(1); 40 CFR 51.166(b)(2).

This structure of the EPA's PSD regulations created questions regarding the extent to which the limitations in the Tailoring Rule would continue to apply to GHGs once they became regulated, through this final rule, under section 111 of the CAA. 79 FR 1487–1488. As discussed above, the definition of ''regulated NSR pollutant'' in the PSD regulations contains a separate PSD trigger for air pollutants regulated under the NSPS, 40 CFR 51.166(b)(49)(ii) (the ''NSPS trigger provision''). Thus, when GHGs become subject to a standard promulgated under CAA section 111 for the first time under this rule, PSD requirements would presumably apply for GHGs on an additional basis besides through the regulation of GHGs from motor vehicles. However, the Tailoring Rule, on the face of its regulatory provisions, incorporated the revised thresholds it promulgated into only the fourth subpart of the PSD definition of regulated NSR pollutant (''[a]ny pollutant that otherwise is subject to regulation under the Act''). The regulatory text does not clearly incorporate the thresholds into the NSPS trigger provision in the second subpart (''[a]ny pollutant that is subject to any standard promulgated under section 111 of the Act''). For this reason, a question arose as to whether the Tailoring Rule limitations would continue to apply to the PSD requirements after they are independently triggered for GHGs by the NSPS that the EPA is now promulgating. Stakeholders questioned whether the EPA must revise its PSD regulations —and, by the same token, whether states must revise their SIPs— to assure that the Tailoring Rule thresholds will continue to apply to sources potentially subject to PSD under the CAA based on GHG emissions.

In the January 8, 2014 proposed rule, the EPA explained that the agency had included an interpretation in the Tailoring Rule preamble, which means that the Tailoring Rule thresholds continue to apply if and when the EPA promulgates requirements under CAA section 111. 79 FR 1488 (citing 75 FR 31582). Nevertheless, to ensure there would be no uncertainty as to this issue, the EPA proposed to adopt explicit language in 40 CFR 60.46Da(j), 40 CFR 60.4315(b), and 40 CFR 60.5515 of the agency's regulations. The proposed language makes clear that the thresholds for GHGs in the EPA's PSD definition of ''subject to regulation'' apply through the second subpart of the definition of ''regulated NSR pollutant'' to GHGs regulated under this rule.

The EPA received comments supporting the adoption of this proposed language, but several commenters also expressed concern that adding this language to part 60 alone would not be sufficient. Several commenters urged the EPA to instead revise the PSD regulations in parts 51 and 52. In addition, commenters expressed concern that further steps were needed to amend the SIPs before there would be certainty that the Tailoring Rule limitations continued to apply after the adoption of CO_2 standards under CAA section 111 in this final rule.

On June 23, 2014, the United States Supreme Court, in *Utility Air Regulatory Group* v. *Environmental Protection Agency,* issued a decision addressing the application of PSD permitting requirements to GHG emissions. The Supreme Court held that the EPA may not treat GHGs as an air pollutant for purposes of determining whether a source is a major source (or modification thereof) for the purpose of PSD applicability. The Court also said that the EPA could continue to require that PSD permits, otherwise required based on emissions of pollutants other than GHGs, contain limitations on GHG emissions based on the application of BACT. The Supreme Court decision effectively upheld PSD permitting requirements for GHG emissions under Step 1 of the Tailoring Rule for ''anyway sources'' and invalidated application of PSD permitting requirements to Step 2 sources based on GHG emissions. The Court also recognized that, although the EPA had not yet done so, it could ''establish an appropriate *de minimis* threshold below which BACT is not required for a source's greenhouse gas emissions.'' 134 S. Ct. at 2449.

In accordance with the Supreme Court decision, on April 10, 2015, the U.S. Court of Appeals for the District of Columbia Circuit (the D.C. Circuit) issued an amended judgment vacating the regulations that implemented Step 2 of the Tailoring Rule, but not the regulations that implement Step 1 of the Tailoring Rule. The court specifically vacated 40 CFR 51.166(b)(48)(v) and 40 CFR 52.21(b)(49)(v) of the EPA's regulations, but did not vacate 40 CFR 51.166(b)(48)(iv) or 40 CFR 52.21(b)(48)(iv). The court also directed the EPA to consider whether any further revisions to its regulations are appropriate in light of *UARG* v. *EPA,* and, if so, to undertake such revisions.

The practical effect of the Supreme Court's clarification of the reach of the CAA is that it eliminates the need for Step 2 of the Tailoring Rule and subsequent steps of the GHG permitting phase in that the EPA had planned to consider under the Tailoring Rule. This also eliminates the possibility that the promulgation of GHG standards under section 111 could result in additional sources becoming subject to PSD based solely on GHGs, notwithstanding the limitations the EPA adopted in the Tailoring Rule. However, for an interim period, the EPA and the states will need to continue applying parts of the PSD definition of ''subject to regulation'' to ensure that sources obtain PSD permits meeting the requirements of the CAA.

The CAA continues to require that PSD permits issued to ''anyway sources'' satisfy the BACT requirement for GHGs. Based on the language that remains applicable under 40 CFR 51.166(b)(48)(iv) and 40 CFR 52.21(b)(49)(iv), the EPA and states may continue to limit the application of BACT to GHG emissions in those circumstances where a source emits GHGs in the amount of at least 75,000 tpy on a CO_2e basis. The EPA's intention is for this to serve as an interim approach while the EPA moves forward to propose a GHG Significant Emission Rate (SER) that would establish a *de minimis* threshold level for permitting GHG emissions under PSD. Under this forthcoming rule, the EPA intends to propose restructuring the GHG provisions in its PSD regulations so that the *de minimis* threshold for GHGs will not reside within the definition of ''subject to regulation.'' This restructuring will be designed to make the PSD regulatory provisions on GHGs universally applicable, without regard to the particular subparts of the definition of ''regulated NSR pollutant'' that may cover GHGs. Upon promulgation of this PSD rule, it will then provide a framework that states may use when updating their SIPs consistent with the Supreme Court decision.

While the PSD rulemaking described above is pending, the EPA and approved state, local, and tribal permitting authorities will still need to implement the BACT requirement for GHGs. In order to enable permitting authorities to continue applying the 75,000 tpy CO_2e threshold to determine whether BACT applies to GHG emissions from an ''anyway source'' after GHGs are subject to regulation under CAA section 111, the EPA has concluded that it continues to be appropriate to adopt the proposed language in 40 CFR 60.5515 (subpart TTTT). Because the EPA is not finalizing the proposed regulations in subparts Da and KKKK, it is not necessary to adopt the comparable provisions that the EPA proposed in 40 CFR 60.46Da(j) and 40 CFR 60.4315(b).

The EPA has evaluated 40 CFR 60.5515 in light of the Supreme Court decision and the comments received on the question of whether this CAA section 111 standard will undermine the application of the Tailoring Rule limitations. While most of the Tailoring Rule limitations are no longer needed to avoid triggering the requirement to obtain a PSD permit based on GHGs alone, the limitation in 40 CFR 51.166(b)(48)(iv) and 40 CFR 52.21(b)(49)(iv) will remain important to provide an interim applicability level for the GHG BACT requirement in ''anyway source'' PSD permits. Thus, there continues to be a need to ensure that the regulation of GHGs under CAA section 111 does not make this BACT applicability level for anyway sources effectively inoperable. The language in 40 CFR 60.5515 will continue to be effective at avoiding this result after the judicial actions described above and the adoption of this final rule. The provisions in part 60 reference 40 CFR 51.166(b)(48) and 40 CFR 52.21(b)(49) of the EPA's regulations. However, the courts have now vacated 40 CFR 51.166(b)(48)(v) and 40 CFR 52.21(b)(49)(v), and the EPA will take steps soon to eliminate these subparts from the CFR. As a result of these steps, the language of final 40 CFR 60.5515 will not incorporate the vacated parts of 40 CFR 51.166(b)(48) and 40 CFR 52.21(b)(49), but these provisions in part 60 will continue to apply to those subparts of the PSD rules that are needed on an interim basis to limit application of BACT to GHGs only when emitted by an anyway source in amounts of 75,000 tpy CO_2e or more. Thus, in this final rule, the EPA is adopting the proposed text of 40 CFR 60.5515 for this purpose without substantial change.

As to the concern expressed by some commenters that revisions to part 60 alone are not sufficient, the GHG SER rulemaking described above will include proposed revisions to the PSD regulations in parts 51 and 52 that should ultimately address this concern. The EPA acknowledges that the commenters concern will not be fully addressed for an interim period of time, but (for the reasons discussed above) the part 60 provisions adopted in this rule are sufficient to make explicit that the 75,000 tpy CO_2e BACT applicability level for GHGs will apply to GHGs that are subject to regulation under the CAA section 111 standards adopted in this rule.

Rather than adopting a temporary patch in its PSD regulations in this rule to address the implications for PSD of regulating GHGs under CAA section 111, the EPA believes it will be most efficient for the EPA and the states if the EPA completes a comprehensive PSD rule that will address all the implications of the Supreme Court decision. The revisions the EPA will consider based on the Supreme Court decision will inherently address the commenters concerns about the definition of the ''subject to regulation'' and the proposed part 60 provisions. To the extent this PSD rule is not complete before the EPA proposes additional CAA section 111 standards for GHGs, the EPA will need to consider adding provisions like 40 CFR 60.5515 to other subparts of part 60. In a separate rulemaking finalized concurrently with this rule, the EPA is also finalizing corresponding edits to 40 CFR 60.5705 in subpart UUUU to clarify that the regulated pollutant is the same for both the CAA section 111(b) and section 111(d) rules. As of this time, the EPA has not proposed GHG standards for other source categories under CAA section 111. To the extent needed, this approach of adding provisions to a few subparts in part 60 would be less burdensome to states and more efficient than revising 40 CFR 51.166 at this time solely to address the implications of regulating GHGs under CAA section 111.

The EPA understands that many commenters expressed concern that PSD SIPs would also have to be amended to address the implications of regulating GHGs under CAA section 111. However, the language in 40 CFR 60.5515 is designed to avoid the need for states to make revisions to the PSD regulations in their SIPs at this time. The EPA has previously observed that the form of each pollutant regulated under the PSD program is derived from the form of the pollutant described in regulations, such as an NSPS, that make the pollutant regulated under the CAA. 56 FR 24468, 24470 (May 30, 1991); 61 FR 9905, 9912–18 (Mar. 12, 1996); 75 FR 31522.

Moreover, it is more likely that states would need to consider a SIP revision if the EPA were to revise 40 CFR 51.166 in this rule. Revisions to 51.166 can trigger requirements for states to revise their PSD program provisions under 40 CFR 51.166(a)(6).

Given the process required in states to review their SIPs and submit them to the EPA for approval, it is most efficient for all concerned when the EPA is able to consolidate its revisions to 40 CFR 51.166. The EPA, thus, believes it will be less work for states if we issue a comprehensive set of rules addressing regulation of GHGs under the PSD program after the Supreme Court decision.

In comments on the proposed rules, states generally did not express concern that the proposed revisions to part 60 were insufficient to avoid the need for SIP revisions. In our proposal, we addressed any state with an approved PSD SIP program that applies to GHGs which believed that this final rule would require the state to revise its SIP so that the Tailoring Rule thresholds continue to apply. First, the EPA encouraged any state that considered such revisions necessary to make them as soon as possible. Second, if the state could do so promptly, the EPA said it would assess whether to proceed with a separate rulemaking action to narrow its approval of that state's SIP so as to assure that, for federal purposes, the Tailoring Rule thresholds will continue to apply as of the effective date of the final NSPS rule. 79 FR 1487. The EPA did not receive any comments or other feedback from states requesting that the EPA narrow their program to ensure the Tailoring Rule thresholds continue to apply after promulgating this rule. We do not believe such action will be necessary in any state after the Supreme Court decision and our action in this rule is to adopt the proposed part 60 provisions for purposes of ensuring the Step 1 BACT applicability level for GHGs continues to apply on an interim basis.

C. Implications for BACT Determinations Under PSD

New major stationary sources and major modifications at existing major stationary sources are required by the

CAA to, among other things, obtain a permit under the PSD program before commencing construction. The emission thresholds that define PSD applicability can be found in 40 CFR parts 51 and 52, and the PSD thresholds specific to GHGs are explained in the preceding section of this preamble.

Sources that are subject to PSD must obtain a preconstruction permit that contains emission limitations based on application of BACT for each regulated NSR pollutant. The BACT requirement is set forth in section 165(a)(4) of the CAA, and in EPA regulations under 40 CFR parts 51 and 52. These provisions require that BACT determinations be made on a case-by-case basis. CAA section 169(3) defines BACT, in general, as:

''an emissions limitation . . . based on the maximum degree of reduction for each pollutant . . . emitted from any proposed major stationary source or major modification which the Administrator . . . [considering energy, environmental, and economic impacts] . . . determines is achievable for such facility . . .''

Furthermore, this definition in the CAA specifies that

''[i]n no event shall application of [BACT] result in emissions of any pollutants which will exceed the emissions allowed by any applicable standard established pursuant to section 111 or 112 of the Act.''

This condition of CAA section 169(3) has historically been interpreted to mean that BACT cannot be less stringent than any applicable standard of performance under the NSPS. *See, e.g.,* U.S. EPA, PSD and Title V Permitting Guidance for Greenhouse Gases, EPA–457/B–11–001 (March 2011) (''GHG Permitting Guidance'' or ''Guidance'') at 20–21. Thus, upon completion of an NSPS, the NSPS establishes a ''BACT Floor'' for PSD permits that are issued to affected facilities covered by the NSPS.

BACT is a case-by-case review that considers a number of factors. These factors include the availability, technical feasibility, control effectiveness, and the economic, environmental and energy impacts of the control option. See GHG Permitting Guidance at 17–46. The fact that a minimum control requirement (*i.e.,* the BACT Floor) is established by the EPA through an applicable NSPS does not bar a permitting agency from justifying a more stringent control level as BACT for a specific PSD permit.

It is important to understand how this NSPS may relate to determining BACT for new and existing EGUs that require PSD permits. PSD generally applies to major sources, while this NSPS applies to units that may be within a source. Under this NSPS, an affected facility is a new EGU or a modified or reconstructed EGU. The new source NSPS requirements apply, in general, to any stationary source that adds a new EGU that is an affected facility under this NSPS. This could, for example, include a proposed brand new (''greenfield'') power plant or an existing power plant that proposes to add a new EGU (*e.g.,* to increase its generating capacity). While this latter scenario is considered a ''new affected facility'' under the NSPS, it is generally viewed under PSD as a ''modification'' of an existing stationary source. Thus, the new source NSPS requirements could apply to a modification, as that term is defined under PSD.

In addition, this NSPS will apply to some modified and reconstructed units, as those terms are defined under part 60. Consequently, this NSPS could establish a BACT floor for existing stationary sources that are modifying an existing EGU and experience an emissions increase that makes the source subject to PSD review. However, a physical change that triggers the NSPS modification or reconstruction requirements does not necessarily subject the source to PSD requirements, and vice versa. In general, in order to trigger the NSPS modification or reconstruction requirements, a physical change must increase the maximum hourly emission rate of the pollutant (to be an NSPS modification) or the fixed capital cost of the change must exceed 50 percent of the fixed capital cost of a comparable entirely new facility (to be an NSPS reconstruction). *See* 40 CFR 60.2, 60.14, 60.15. Under the PSD program, however, a physical change (or change in the method of operation) must result in an increase in annual emissions of the pollutant by a specified emission threshold in order to be subject to PSD requirements. This emission calculation considers the unit's past annual emissions and its projected annual emissions. See, *e.g.,* 40 CFR 52.21(a)(2)(iv)(C). In addition, the PSD emissions test for a modification allows the existing source to consider qualifying emission reductions and increases at the source within a contemporaneous period to ''net out'' of, or avoid, triggering PSD review. Thus, it is important to understand the differences in how the term ''modification'' is used in the NSPS and PSD programs, and that a physical change that is a modification under one program may not necessarily be a modification under the other program.

In the preamble to the proposed NSPS for new sources, the EPA discussed whether a standard of performance for the new source NSPS, specifically the BSER for solid fuel-fired EGUs that is based on partial CCS, could become the BACT floor when permitting a modified or reconstructed EGU or non-EGU source. As noted above, BACT is a case-specific review by a permitting agency. In evaluating BACT, the permitting authority should consider all available control technologies that have the potential for practical application to the facility or emission unit under evaluation. See GHG Permitting Guidance at 24. This BACT review must include any technologies that are part of an applicable NSPS for the specific type of source and would therefore establish the minimum level of stringency for the BACT. Thus, it is possible that partial CCS could be considered in a BACT review as an available control option for a modified or reconstructed EGU facility, or for another type of source (*e.g.,* natural gas processing plant), but this NSPS is not an applicable standard to such sources so it would not establish a requirement that partial CCS is a minimum level of stringency for the BACT for those sources.

Some commenters expressed concern that, if the EPA finalizes a BSER for utility boilers and IGCC units that is based on partial CCS, it would establish a BACT Floor for new EGUs that would be inconsistent with prior BACT determinations for EGUs in both permits issued by EPA Regions and permits issued by state agencies on which the EPA has commented. Many of these comments were more directed at the development and deployment of CCS (*i.e.,* the commenter did not believe CCS should be the basis for BSER) rather than examining whether an NSPS should establish the BACT floor for applicable sources, which is the legal consequence of setting an NSPS under the terms of the CAA. Consequently, we respond to these comments in other sections of this preamble that support the selection of partial CCS as the basis for the BSER for fossil fuel-fired electric utility steam generating units.

With regard to the commenters who stated that a BSER for EGUs that is based on partial CCS would be inconsistent with BACT determinations in previous GHG PSD permits, it is important to recognize that a BACT determination is a case-by-case analysis and that technological capabilities and costs evolve over time.[551] In addition, to

[551] In this regard, the 2011 GHG Permitting Guidance states that ''although CCS is not in widespread use at this time, EPA generally considers CCS to be an 'available' add-on pollution control technology for facilities emitting CO_2 in

Continued

date the EPA has not issued a PSD permit with GHG BACT for a source that would be an affected facility requiring partial CCS under this NSPS (*i.e.,* a fossil fuel-fired steam generating unit), so one cannot determine whether the EPA—as a PSD permitting authority—has been either consistent or inconsistent by setting a BSER of partial CCS in this NSPS. Although, in the course of a BACT review, some permitting authorities may have determined that CCS is not technologically feasible or economically achievable for a gas-fired EGU, because of the case-by-case nature of the BACT analysis it does not automatically follow that the same conclusion is appropriate for a solid fuel-fired EGU. Furthermore, PSD permitting requirements first applied to GHGs in January 2011 and more information about GHG control technology has been gained in this four-and-a-half year period. Thus, we would expect BACT decisions to evolve as well, such that a GHG BACT review for a coal-fired EGU in 2015 may look very different from a review that was done in 2011.

Additionally, if a state agency is processing a permit application for a solid fuel-fired EGU and does not propose CCS as BACT (or does not even consider CCS as an available control for BACT), the EPA is not necessarily required to comment negatively on the draft permit, or to otherwise request or require that the state agency amend the BACT to include CCS. For state agencies that have their own EPA-approved state implementation plan, the state has primacy over their permitting actions and discretion to interpret their approved rules and to apply the applicable federal and state regulatory requirements that are in place at the time for the facility in question. The EPA's role is to provide oversight to ensure that the state operates their PSD program in accordance with the CAA and applicable rules. If the EPA does not adversely comment on a certain draft permit or BACT determination, it does not necessarily imply EPA endorsement of the proposed permit or determination.

Some commenters also felt that the determination of partial CCS as BSER is inconsistent with the agency's position on CCS in the EPA's GHG Permitting Guidance, which they say supports the notion that additional work is required before CCS can be integrated at full-scale electric utility applications. It is important to recognize that the EPA's Permitting Guidance is guidance, so it does not contain any final determination of BACT for any source. Furthermore, we disagree with the commenters' characterization of the GHG Permitting Guidance. The Guidance specifically states ''[f]or the purposes of a BACT analysis for GHGs, the EPA classifies CCS as an add-on pollution control technology that is ''available'' for facilities emitting CO_2 in large amounts, including fossil fuel-fired power plants, and for industrial facilities with high-purity CO_2 streams (*e.g.,* hydrogen production, ammonia production, natural gas processing, ethanol production, ethylene oxide production, cement production, and iron and steel manufacturing). For these types of facilities, CCS should be listed in Step 1 of a top-down BACT analysis for GHGs.'' GHG Permitting Guidance at 32. As discussed elsewhere in the Guidance, technologies that should be listed in Step 1 are those that ''have the potential for practical application to the emissions unit and regulated pollutant under evaluation.'' GHG Permitting Guidance at 24. The EPA continues to stand by its position on the availability of CCS in this context, as expressed in the GHG Permitting Guidance.

The GHG Permitting Guidance continues on to discuss case-specific factors and potential limitations with applying CCS, and it acknowledges that CCS may not be ultimately selected as BACT in ''certain cases'' based on technology feasibility and cost. GHG Permitting Guidance at 36, 43. While acknowledging these potential challenges when it was issued in March 2011, the Guidance clearly does not rule out the selection of CCS as BACT for any source category and it is forward looking. GHG Permitting Guidance at 43 (''. . . as a result of ongoing research and development, . . . CCS may become less costly and warrant greater consideration . . . in the future'') Nothing in the Guidance is inconsistent with EPA's present position that CCS is adequately demonstrated for the types of sources covered by this NSPS, as articulated elsewhere in this preamble.

A commenter asserted that the GHG Permitting Guidance should be amended because it calls for consideration of CCS in BACT determinations even though the proposed NSPS identified ''partial CCS'' as BSER for new boiler and IGCC EGUs. The Guidance explains that ''the purpose of Step 1 of the process is to cast a wide net and identify all control options with potential application to the emissions unit under review.'' GHG Permitting Guidance at 26. The EPA agrees that the GHG Permitting Guidance only uses the term ''CCS'' and does not distinguish ''partial CCS'' from ''full CCS.'' But considering the purpose of Step 1 of the process, we believe that the term ''CCS'', as it is used in the GHG Permitting Guidance, adequately describes the varying levels of CO_2 capture. A BACT review should analyze all available technologies in order to adequately support the BACT determination, and may require evaluation of partial CCS, full CCS, and/or no CO_2 capture. The specific facility type and CO_2 capture conditions will dictate the level(s) of CO_2 capture that are most appropriate to consider as ''available'' in a BACT review.

D. Implications for Title V Program

Under the Title V program, certain stationary sources, including ''major sources'' are required to obtain an operating permit. This permit includes all of the CAA requirements applicable to the source, including adequate monitoring, recordkeeping, and reporting requirements to assure sources' compliance. These permits are generally issued through EPA-approved state Title V programs.

In the January 8, 2014 proposal, the EPA discussed whether this rulemaking would impact the applicability of Title V requirements to major sources of GHGs. 79 FR 1489–90. The relevant issue for Title V purposes was, in essence, whether promulgation of CAA section 111 requirements for GHGs

---

large amounts and industrial facilities with high-purity CO_2 streams.'' GHG Permitting Guidance at 35. The Guidance goes on to note that CCS may not be technically feasible at modified sources (citing possible issues with ''space for CO_2 capture equipment at an existing facility''), or in other specific circumstances. Id. at 36 (''Logistical hurdles for CCS may include obtaining contracts for offsite land acquisition . . ., the need for funding . . ., timing of available transportation infrastructure, and developing a site for secure long term storage. Not every source has the resources to overcome the offsite logistical barriers necessary to apply CCS technology to its operations, and smaller sources will likely be more constrained in this regard''). Id. at 42–3 EPA also noted that CCS may be expensive in individual instances and thus eliminated as a control option for that reason under step 4 of the BACT analysis, noting further that revenues from EOR may offset other costs. Id. at 42–3. See also *UARG* v. *EPA,* 134 S.Ct. 2427, 2448 (2014) (noting that EPA's GHG Permitting Guidance states that carbon capture is reasonably comparable to more traditional, end-of-stack BACT technologies, and that petitioners do not dispute that).

As explained at Section V.I.5 above, in determining that partial CCS is BSER for new fossil fuel steam electric plants, the EPA has carefully considered the issue of logistics (including cost estimates for land acquisition, transportation, and sequestration) and costs generally. Nor would new plants face the same types of constraints as modified or reconstructed sources in a BACT determination, since a new source has more leeway in choosing where to site. See text at V.G.3. above. Moreover, the GHG Permitting Guidance considered BACT determinations for all types of sources, not just those for which the EPA has determined in this rule that partial CCS is the BSER, and the concerns expressed in the Guidance thus must be considered in that broader context.

would undermine the Tailoring Rule, which, as explained above, phased in permitting requirements for GHG emissions for stationary sources under the CAA PSD and Title V permitting programs. Based on the EPA's understanding of the CAA at that time, the proposal discussed this issue in the context of the regulatory and statutory definitions of ''major source,'' focusing on revisions that had been made in the Tailoring Rule to the definitions in the Title V regulations of ''major source'' and ''subject to regulation.'' 79 FR 1489–90 (quoting 75 FR 31583). Under the Title V regulations, as revised by the Tailoring Rule, ''major source'' is defined to include, in relevant part, ''a major stationary source . . . that directly emits, or has the potential to emit, 100 tpy or more of any air pollutant subject to regulation.'' The proposal further explained that the GHG threshold that had been established in the Tailoring Rule had been incorporated into the definition of ''subject to regulation'' under 40 CFR 70.2 and 71.2, such that those definitions specify '' 'that GHGs are not subject to regulation for purposes of defining a major source, unless as of July 1, 2011, the emissions of GHGs are from a source emitting or having the potential to emit 100,000 tpy of GHGs on a CO_2e basis.' '' *Id.* (quoting 75 FR 31583). The proposal thus concluded that the Title V definition of ''major source,'' as revised by the Tailoring Rule, did not on its face distinguish among types of regulatory triggers for Title V. It further noted that the Title V program had already been triggered for GHGs, and thus concluded that the promulgation of CAA section 111 requirements would not further impact Title V applicability requirements for major sources of GHGs. 79 FR 1489–90.

As noted elsewhere in this section, after the proposal for this rulemaking was published, the United States Supreme Court issued its opinion in *UARG* v. *EPA,* 134 S.Ct. 2427 (June 23, 2014), and in accordance with that decision, the D.C. Circuit subsequently issued an amended judgment in *Coalition for Responsible Regulation, Inc.* v. *Environmental Protection Agency,* Nos. 09–1322, 10–073, 10–1092 and 10–1167 (D.C. Cir., April 10, 2015). Those decisions support the same overall conclusion as the EPA discussed in the proposal, though for different reasons.

With respect to Title V, the Supreme Court said in *UARG* v. *EPA* that the EPA may not treat GHGs as an air pollutant for purposes of determining whether a source is a major source required to obtain a Title V operating permit. In accordance with that decision, the D.C. Circuit's amended judgment in *Coalition for Responsible Regulation, Inc.* v. *Environmental Protection Agency,* vacated the Title V regulations under review in that case to the extent that they require a stationary source to obtain a Title V permit solely because the source emits or has the potential to emit GHGs above the applicable major source thresholds. The D.C. Circuit also directed the EPA to consider whether any further revisions to its regulations are appropriate in light of *UARG* v. *EPA,* and, if so, to undertake to make such revisions. These court decisions make clear that promulgation of CAA section 111 requirements for GHGs will not result in the EPA imposing a requirement that stationary sources obtain a Title V permit solely because such sources emit or have the potential to emit GHGs above the applicable major source thresholds.[552]

To be clear, however, unless exempted by the Administrator through regulation under CAA section 502(a), any source, including an area source (a ''non-major source''), subject to an NSPS is required to apply for, and operate pursuant to, a Title V permit that assures compliance with all applicable CAA requirements for the source, including any GHG-related applicable requirements. This aspect of the Title V program is not affected by *UARG* v. *EPA,* as the EPA does not read that decision to affect either the grounds other than those described above on which a Title V permit may be required or the applicable requirements that must be addressed in Title V permits.[553] Consistent with the proposal, the EPA has concluded that this rule will not affect non-major sources and there is no need to consider whether to exempt non-major sources. Thus, sources that are subject to the CAA section 111 standards promulgated in this rule are required to apply for, and operate pursuant to, a Title V permit that assures compliance with all applicable CAA requirements, including any GHG-related applicable requirements.

E. Implications for Title V Fee Requirements for GHGs

1. Why is the EPA revising Title V fee rules as part of this action?

The January 8, 2014 notice of proposed rulemaking (79 FR 1430) (the ''EGU GHG NSPS proposal'' or ''NSPS proposal'') proposed the first section 111 standards to regulate GHGs at EGUs. That notice also included proposed revisions to the fee requirements of the 40 CFR part 70 and part 71 operating permit rules under Title V of the CAA to avoid inadvertent consequences for fees that would be triggered by the promulgation of the first CAA section 111 standard to regulate GHGs. If we do not revise the fee rules by the time of the promulgation of the NSPS standards for GHGs, then approved part 70 programs implemented by state, local and tribal permitting authorities[554] that rely on the ''presumptive minimum'' approach and the part 71 program implemented by the EPA would be required to account for GHGs in emissions-based fee calculations at the same dollar per ton ($/ton) rate as other air pollutants. The EPA believes this would result in the collection of fees in excess of what is required to cover the reasonable costs of an operating permit program. See NSPS proposal 79 FR 1490.

In response to these concerns, the EPA proposed regulatory changes to limit the fees collected based on GHG emissions and proposed two fee adjustment options to increase the fees collected based on the costs for permitting authorities to conduct certain review activities related to GHG emissions, while still providing sufficient funding for an operating permit program. Also, we proposed an option that would have provided for no fee adjustments to recover the costs of conducting review activities related to GHG emissions. *Id.* 79 FR 1490. The EPA did not propose any action related to state and local permitting authorities that do not use the presumptive minimum approach.

Most commenters on the proposal, including state and local permitting authorities, were supportive of exempting GHGs from the emissions-based fee calculations of the permit

[552] As explained elsewhere in this notice, the EPA intends to conduct future rulemaking action to make the appropriate revisions to the operating permit rules to respond to the Supreme Court decision and the D.C. Circuit's amended judgment. To the extent there are any issues related to the potential interaction between the promulgation of CAA section 111 requirements for GHGs and Title V applicability based on emissions above major source thresholds, the EPA expects there would be an opportunity to consider those during that rulemaking.

[553] See Memorandum from Janet G. McCabe, Acting Assistant Administrator, Office of Air and Radiation, and Cynthia Giles, Assistant Administrator, Office of Enforcement and Compliance Assurance, to Regional Administrators, Regions 1–10, *Next Steps and Preliminary Views on the Application of Clean Air Act Permitting Programs to Greenhouse Gases Following the Supreme Court's Decision in Utility Regulatory Group* v. *Environmental Protection Agency* (July 24, 2014) at 5.

[554] Hereafter, for the sake of simplicity, we will generally refer to part 70 permitting authorities as ''state'' permitting authorities and refer to part 70 programs as ''state'' programs.

rules, but support for the fee adjustment options was mixed, with state and local permitting authorities generally supporting either of the two fee adjustments, and other commenters generally supporting the option that provides for no fee adjustment.

2. Background on the Fee Requirements of Title V

In the NSPS proposal, the EPA explained the statutory and regulatory background related to the requirement that permitting authorities collect fees from the owner or operator of Title V sources that are sufficient to cover the costs of the operating permit program. CAA section 502(b)(3)(A) requires an operating permit program to include a requirement that sources ''pay an annual fee, or the equivalent over some other period, sufficient to cover all reasonable (direct and indirect) costs required to develop and administer the permit program.'' See also 40 CFR 70.9(a). CAA section 502(b)(3)(B)(i) requires that, in order to have an approvable operating permit program, the permitting authority must show that ''the program will result in the collection, in the aggregate, from all sources [required to get an operating permit]'' of either ''an amount not less than $25 per ton of each regulated pollutant [adjusted annually for changes in the consumer price index], or such other amount as the Administrator may determine adequately reflects the reasonable costs of the permit program.'' See also 40 CFR 70.9(b)(2). This has been generally referred to as the ''presumptive minimum'' approach. If a permitting authority does not wish to use the presumptive minimum approach, it may demonstrate ''that collecting an amount less than the [presumptive minimum amount] will'' result in the collection of funds sufficient to cover the costs of the program. CAA section 503(b)(3)(B)(iv); see also 40 CFR 70.9(b)(5). This has been generally referred to as the ''detailed accounting'' approach. CAA section 502(b)(3)(B)(ii) sets forth a definition of ''regulated pollutant'' for purposes of calculating the presumptive minimum that includes each pollutant regulated under section 111 of the CAA. See also 40 CFR 70.2.

3. What fee rules did we propose to revise?

In the NSPS proposal, to exempt GHGs from emissions-based fee calculations, we proposed to exempt GHGs from the definition of ''regulated pollutant'' for purposes of operating permit fee calculations (''the GHG exemption''). The EPA then proposed two alternative ways to account for the costs of addressing GHGs in operating permits through a cost adjustment. First, we proposed a modest additional cost for each GHG-related activity of certain types that a permitting authority would process (''the GHG adjustment option 1''). Alternatively, we proposed a modest additional increase in the per ton rate used in the presumptive minimum calculation for all non-GHG fee pollutants (''the GHG adjustment option 2''). The EPA also solicited comment on an option that would provide no additional cost adjustment to account for GHGs (''the GHG adjustment option 3''). All of the GHG adjustment options are based on the assumption that the GHG exemption is finalized. See NSPS Proposal 79 FR 1493–1495.

The EPA additionally proposed two clarifications. The first was regulatory text in 40 CFR part 60, subparts Da, KKKK, and TTTT, to clarify that GHGs, as opposed to CO_2, is the regulated pollutant for fee purposes (''the fee pollutant clarification''). *Id.* at 1505, 1506 and 1511. The second was a proposal to move the existing definition of ''Greenhouse gases (GHGs)'' within 40 CFR 70.2 and 71.2 to promote clarity in the regulations (''the GHG clarification''). *Id.* 79 FR 1490, 1517, 1518.

For background purposes, below is a brief summary of each of the proposals.

a. The GHG Exemption

To address the fee issues discussed in the NSPS proposal, the EPA proposed to exempt GHG emissions from the definition of ''regulated pollutant (for presumptive fee calculation)'' in 40 CFR 70.2 and the definition of ''regulated pollutant (for fee calculation)'' in 40 CFR 71.2.[555] See NSPS preamble 79 FR 1493, 1495.

b. The GHG Adjustment Option 1

The first proposed ''GHG adjustment'' option (option 1) was to include an additional cost for each GHG-related activity of certain types that a permitting authority would process (an activity-based adjustment). The three activities identified for this option were ''GHG completeness determination (for initial permit or for updated application)'' at 43 hours of burden,[556] ''GHG evaluation for a modification or related permit action'' at 7 hours of burden, and ''GHG evaluation at permit renewal'' at 10 hours of burden. See also 79 FR 1494, fn. 280 (providing a description of each of these activities).

For part 70, the burden hours per activity would be multiplied by the cost of staff time (in $/hour) specific to the state, including wages, benefits, and overhead, to determine the cost of each activity. All the activities for a given period would be totaled to determine the total GHG adjustment for the state. See 79 FR 1494.

For part 71, we proposed a labor rate assumption of $52 per hour in 2011 dollars. Using that labor rate, we proposed to determine the GHG fee adjustment for each GHG permitting program activity to be a specific dollar amount for each activity (''set fees'') that the source would pay for each activity performed. See 79 FR 1495. The EPA proposed to revise 40 CFR 70.9(b)(2)(v) and 40 CFR 71.9(c)(8) to implement this option.

c. The GHG Adjustment Option 2

The second proposed GHG adjustment option (option 2) was to increase the dollar per ton ($/ton) rates used in the fee calculations for each non-GHG fee pollutant. The revised $/ton rates would be multiplied by the total tons of non-GHG fee pollutants actually emitted by any source to determine the applicable total fees. The EPA proposed to increase the $/ton rates by 7 percent.[557] See NSPS proposal 79 FR 1494, 1495.

d. The GHG Adjustment Option 3

The EPA also solicited comment on not charging any fees related to GHGs (option 3). The basis for this proposed option was the observation that most sources that need to address GHGs in a permit would also emit non-GHG fee pollutants, and thus, the cost of permitting for any particular source may be accounted for adequately without charging any additional fees related to GHGs. *Id.* 79 FR 1494–1495.

e. The Fee Pollutant Clarification

Another fee-related proposal was to add regulatory text to 40 CFR part 60, subparts Da, KKKK, and TTTT, to clarify that the fee pollutant for operating permit purposes would be considered to be ''GHGs,'' (as defined in

[555] Hereafter we will refer to these definitions as the ''fee pollutant'' definitions. Also, note that both fee pollutant definitions cross-reference the definitions of ''regulated air pollutant'' which includes air pollutants ''subject to any standard promulgated under section 111 of the Act.''

[556] Burden is the hours of staff time necessary to perform a task.

[557] The EPA estimated that both options 1 and 2 would result in about a 7 percent increase in the fees collected by operating permit programs affected by the proposed rule. For example, the presumptive minimum fee rate in effect for September 1, 2014 through August 31, 2015 is $48.27/ton. A 7 percent increase under option 2 would result in a revised fee of $51.65/ton.

40 CFR 70.2 and 71.2),[558] rather than solely CO_2, which would be regulated under the section 111 standards and implemented through the EGU GHG NSPS. *Id.* 79 FR 1505, 1506, and 1511.

f. The GHG Clarification

The EPA proposed to move the existing definition of ''Greenhouse gases (GHGs)'' within the definition of ''Subject to regulation'' in 40 CFR 70.2 and 71.2 to a separate definition within those sections to promote clarity in the regulations. *Id.* 79 FR 1490, 1517, 1518.

4. What action is the EPA finalizing?

In this action, the EPA is finalizing the following elements as proposed: (1) The GHG exemption, (2) the GHG adjustment option 1, and (3) the fee pollutant clarification.

Public commenters on the proposal stated both support and opposition to using the NSPS rulemaking action to revise the Title V fee rules. Two commenters stated that proposing the Title V fee revisions within the NSPS rulemaking would result in fewer commenters, particularly state and local permitting authorities, having knowledge of the changes to the fee rules and sufficient opportunity to comment on the changes because the NSPS proposal is limited to a single source category, and one stated that a separate proposal for the fee rules would provide a sufficient opportunity for public comment. The EPA believes it is appropriate to move forward with final action amending the Title V fee regulations as part of this NSPS. As we explained in the preamble for the proposal and elsewhere in this final rule, the fee rules and the section 111 standards are interrelated because, if we do not revise the fee rules, promulgation of the final NSPS will trigger certain requirements related to Title V fees for GHG emissions that the EPA believes will result in the collection of excessive fees in states that implement the presumptive minimum approach and in the part 71 program. Thus, it is important to finalize the revisions to the fee rules at the same time or prior to this NSPS, and it is within the EPA's discretion to address the NSPS and the fee rules at the same time as part of the same rulemaking action. In response to the commenters who were concerned that including the fee rule proposal as part of the NSPS proposal would result in the public not having sufficient public comment opportunities, the EPA believes sufficient public comment opportunities were provided on the fee rule changes because the proposal met all public participation requirements and we provided additional public outreach, including to state and local permitting authorities, which discussed the fee rule proposal. In addition to the publication of the proposed rulemaking in the **Federal Register**, the EPA held numerous hearings, reached out to state partners and the public, and developed numerous fact sheets and other information to support public comment on this rule. The EPA has complied with the applicable public participation requirements and executive orders. The proposal met all the requirements for public notice—it contained a clear and detailed explanation of how the part 70 and 71 rules would be affected by the promulgation of the CAA section 111 standard for EGUs and how the EPA proposed to revise the related regulatory provisions. We received many comments on the proposal to revise the fee rule for operating permits programs, and we are taking those comments into consideration in the finalization of the rulemaking action.

a. The GHG Exemption

The EPA is taking final action to revise the definition of regulated pollutant (for presumptive fee calculation) in 40 CFR 70.2 and regulated pollutant (for fee calculation) in 40 CFR 71.2 to exempt GHG emissions. This regulatory amendment will have the effect of excluding GHG emissions from being subject to the statutory ($/ton) fee rate set for the presumptive minimum calculation requirement of part 70 and the fee calculation requirements of part 71. We received supportive comments from the majority of public commenters, including state and local permitting authorities and others, on revising the operating permit rules to exempt GHGs from the emission-based calculations that use the statutory fee rates. We are finalizing this portion of the proposal for the same reasons we explained in the proposal notice, including that leaving these regulations unchanged would have resulted in the collection of fee revenue far beyond the reasonable costs of an operating permit program. The EPA believes that these revisions (in conjunction with the GHG adjustment, see below) are consistent with the CAA requirements for fees pursuant to the authority of section 502(b)(3)(B)(i).

Some members of the public opposed the proposed GHG exemption for reasons including that it may limit permitting authorities' ability to charge sufficient fees to cover the cost of GHG permitting[559] if the state is barred from exceeding minimum requirements set by the EPA. Despite this adverse comment, the EPA believes it is appropriate to finalize the GHG exemption because we are not finalizing any requirements that would require states to charge any particular fees to any particular sources. The changes we are finalizing to part 70 concern the presumptive minimum approach, which sets a minimum fee target for states that have decided to follow the presumptive minimum approach. Neither the statute nor the final rule require any state following the presumptive minimum approach (or any other approach) to charge fees to sources using any particular method. Thus, the GHG exemption will not limit states' ability to structure their individual fee programs however they see fit in order to meet the requirement that they collect revenue sufficient to cover all reasonable costs of their permitting program. See CAA section 502(b)(3); 40 CFR 70.9(b)(3).

b. The GHG Adjustment Option 1

The EPA is finalizing GHG adjustment option 1 because we believe it will result in a system for the calculation of costs for part 70 and fees for part 71 that is most directly related to the costs of GHG permitting. The EPA has determined that some adjustment to cost and fee accounting is important because the recent addition of GHG emissions to the operating permitting program does add new burdens for permitting authorities. Although GHG adjustment option 3 (no GHG permitting fee adjustments) was supported by many industrial commenters, the EPA rejected it because it is in tension with the statutory requirement that permitting authorities collect sufficient fees to cover all the reasonable costs of permitting. See CAA section 502(b)(3)(A). Some state and local permitting authorities provided comments supporting option 1, while others supported option 2, and some supported either option, stating no preference. Also, a few state and local permitting authorities supported finalizing no adjustment and a few others asked for flexibility to set fee adjustments not proposed by the EPA, but that they believed would be appropriate for their program.

[558] Note that in 40 CFR 70.2 and 71.2, the term ''Greenhouse gases (GHGs)'' is defined as the ''aggregate group of six greenhouse gases: Carbon dioxide, nitrous oxide, methane, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride.''

[559] We use the term ''GHG permitting'' in this section of the notice to refer to measures undertaken by permitting authorities to ensure that GHGs and any applicable requirements related to GHGs are appropriately addressed in Title V permitting.

The EPA is finalizing option 1 instead of option 2 because the option 1 adjustments are based on the actual costs for permitting authorities to process specific actions that require GHG reviews. The option 2 approach, which would have added a 7 percent surcharge to the $/ton rate used in the fee-related calculations, may have been administratively easier to implement, but is tied to the emissions of non-GHG air pollutants, which are not directly related to the costs of GHG permitting.

Consistent with CAA section 502(b)(3)(B)(i), the Administrator has determined that the final rule's approach of exempting GHG emissions from fee-related calculations and accounting for the GHG permitting costs through option 1 will result in fees that will cover the reasonable costs of the permitting programs.

The EPA is revising the part 70 regulations through this final action, specifically 40 CFR 70.9(b)(2), to modify the presumptive minimum approach to add the activity-based cost of GHG permitting activities, outlined in the revised 40 CFR 70.9(b)(2)(v), to the emissions-based calculation of 40 CFR 70.9(b)(2)(i), which is being revised to now exclude GHG emissions. To determine the activity-based GHG adjustment under 40 CFR 70.9(b)(2)(v), the permitting authority will multiply the burden hours for each activity (set forth in the regulation) by the cost of staff time (in $ per hour), including wages, benefits, and overhead, as determined by the state, for the particular activities undertaken during the particular time period.

States that implement the presumptive minimum approach will need to follow the final rule's option 1 approach.[560] States that use the detailed accounting approach are not directly affected by this rulemaking, but they must ensure that their fee collection programs are sufficient to fully fund all reasonable costs of the operating permit program, including costs attributable to GHG-related permitting. The EPA suggests states that use the detailed accounting approach consider the 7 percent assumption for the costs of GHG permitting in any such analysis, consistent with the EPA analysis of options 1 and 2 in the proposal.

Consistent with 40 CFR 70.4(i), a state that wishes to change its operating permit program as a result of this final rule must apprise the EPA. The EPA will review the materials submitted concerning the change and decide if a formal program revision process is needed and will inform the state of next steps. The communication apprising the EPA of any such changes should include at least a narrative description of the change and any other information that will assist the EPA in its assessment of the significance of the changes. Certain changes, such as switching from the presumptive minimum method to a detailed accounting method, will be considered substantial program revisions and be subject to the requirements of 40 CFR 70.4(i)(2).

With respect to the part 71 program, in this final action the EPA is revising 40 CFR 71.9(c) to require each part 71 source to pay an annual fee which is the sum of the activity-based fee of 40 CFR 71.9(c)(8) and the emissions-based fee of 40 CFR 71.9(c)(1)–(4),[561] which excludes GHG emissions. To determine the activity-based fee, the revised 40 CFR 71.9(c)(8) requires the source to pay a ''set fee'' for each listed activity that has been initiated since the fee was last paid. Under part 71, fees are typically paid at the time of initial application submittal, and thereafter, annually on the anniversary of the initial fee payment, or on any other dates that may be established in the permit. These set fees would not change until such time as we may revise our part 71 rule to change the set fees.

The final rule implements the option 1 approach by listing three activities performed by permitting authorities that involve GHG reviews. The following describes the activities as described in our proposal and certain clarifications we are making in the final rule to ensure consistent implementation.

The EPA is finalizing that the first listed activity under option 1 is ''GHG completeness determination (for initial permit or updated application).'' This activity must be counted for each new initial permit application, even for applications that do not include GHGs emissions or applicable requirements, since an important part of any completeness determination will be to determine that GHG emissions and applicable requirements have been properly addressed, as needed, in the application. The fee for this activity is a one-time charge that covers the initial application and any supplements or updates. The EPA believes that a single charge for a GHG completeness determination will be adequate to cover the reasonable costs for a permitting authority to review an initial application and any subsequent application updates related to initial permit issuance; thus, any updates to an initial application are included in a single ''GHG completeness determination,'' rather than as a separate activity for which the source would be charged in addition to the completeness determination for the initial application. This is an important distinction because many sources submit multiple permit application updates, either voluntarily or as required by the permitting authority, during application review, many of which do not require a separate or comprehensive completeness determination.

The EPA is finalizing regulatory text that would describe the second listed activity as ''GHG evaluation for a permit modification or related permit action.''[562] The EPA had proposed that the second listed activity under option 1 would be ''GHG evaluation for a modification or related permit action.'' For the final rule, we are clarifying that we are adding a cost for a ''permit modification'' rather than for a ''modification.'' The term ''modification'' may be interpreted to refer to any change at a source, even a change that would not be required to be processed as a ''permit modification,'' while ''permit modification'' refers to any revision to an operating permit that cannot be processed as an administrative permit amendment and thus requires a review by a permitting authority as either a significant or minor permit modification.

The EPA is finalizing the third activity as ''GHG evaluation at permit renewal.'' This activity covers the processing of all permit renewal applications and will involve evaluations of whether any GHG applicable requirements are properly included.

Some members of the public commented that finalizing a GHG adjustment would inappropriately

[560] A presumptive minimum state may require various changes to its approved operating permit program before it may begin to implement the option 1 approach. For example, its regulations, and/or program procedures and practices, may need to be revised, depending on the structure of the fee provisions in the state's program; thus, the exact response necessary to address this final action may vary from state to state.

[561] Note that the emissions-based fee calculation differs somewhat depending on whether the part 71 program is being implemented by the EPA (see 40 CFR 71.9(c)(1)); a state, local or tribal agency with delegated authority from the EPA (see § 71.9(c)(2)); the EPA with contractor assistance (see § 71.9(c)(3)); or an agency with partial delegation authority (see § 71.9(c)(4)).

[562] The EPA notes that the term ''permit modification'' in this context refers to all significant permit modifications and minor permit modifications under operating permit rules, but not to ''administrative permit amendments,'' as such amendments are not defined as ''permit modifications'' in the permit rules. See, *e.g.,* 40 CFR 70.7(d), (e), and (f).

increase sources' financial burdens. The EPA has explained, both in the proposal notice and elsewhere in this preamble, the importance of the fee-related revisions to account for the costs associated with GHG-related permitting. The EPA believes that the revisions being finalized will result in modest and reasonable fee increases necessary to cover states' increased costs.[563] To the extent that commenters intended to argue that the adjustments we proposed would exceed the actual costs of GHG permitting, no commenters provided any information or analysis to support that position. Some commenters did state that the costs associated with GHG-related permitting should be minimal because few applicable requirements will apply to GHGs. As stated earlier in this notice, the EPA's cost estimate for the proposal concerned the incremental costs of GHG permitting for any source, not just those that would have, at the time of the analysis, triggered the requirement to get a permit based on GHG emissions or applicable requirements.

Despite some comments received to the contrary, the EPA does not believe it is appropriate to delay the finalization of the GHG adjustment. The EPA does not believe such delays would be consistent with CAA section 502(b)(3)(A) because states have been incurring costs attributable to GHG permitting for several years now and increased fees must be collected to cover the increased costs. The regulatory changes being finalized in this action provide the states with optimal flexibility and sufficient funding to implement their GHG permitting programs. Some commenters had specifically stated that the EPA should delay finalization of this rule until the completion of the next ICR renewal process. While we do not believe delaying this rule is appropriate, as explained above, the EPA notes that we remain committed to collecting and analyzing additional data on costs attributable to GHG permitting for operating permit programs. We may adjust the GHG cost adjustments in future rulemakings if necessary to comply with the requirements of the Act.

As an alternative to the options proposed by the EPA, some commenters asserted that the EPA should make a GHG cost adjustment using a separate, but reduced fee rate ($/ton) for GHGs. We, however, believe that the option 1 approach of the final rule will be more equitable for sources and more representative of actual costs because option 1 considers the costs of the actual permitting activities performed by a particular permitting authority, while any emissions-based approach would not be as directly related to actual costs incurred by permitting authorities.

Some commenters alleged that the EPA's proposal on adjustments to the operating permit programs was vague. The EPA provided a thorough discussion of our rationale in the proposal, including the basis for the GHG adjustments, and we proposed regulatory text to implement our proposal. We explained in the proposal that support for the cost adjustment for GHGs under option 1 is contained in several analyses performed by the EPA and approved by the OMB related to the effect of the addressing GHG requirements in operating permits. These analyses have been placed in the docket for this rulemaking. The analyses include: The Regulatory Impact Assessment (RIA) for the Tailoring Rule (see Regulatory Impact Analysis for the Final Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule, Final Report, May 2010); the part 70 ICR change request for the Tailoring Rule (which was based on the RIA for the Tailoring Rule); and the current ICR for part 70 (EPA ICR number 1587.12; OMB control number 2060–0243).

Several commenters asked that we make changes to the option 1 approach that we proposed, such as adding new activities or decreasing the costs we assumed for the proposal. In response to these comments, we note that we received no quantitative data or other information from commenters that we believe demonstrates the need to revise the list of activities we included under option 1 or the burden hour assumptions under option 1 for the activities. Note that to promote consistent implementation of the final option 1 approach, the preamble describes elsewhere a few clarifications concerning the activities under option 1 and one minor revision to the regulatory text of one of the activities.

Since the EPA's proposed rulemaking, the Supreme Court decided in *UARG* v. *EPA* that the EPA may not treat GHGs as an air pollutant for purposes of determining whether a source is a major source required to obtain a Title V operating permit.[564] The EPA's review of the effect of the Supreme Court decision on the burden hour assumptions for the GHG review activities under proposed option 1 is that the effects are not significant enough to warrant revision of the burden hour assumptions in the final rule. Proposed option 1 was based on the assumption that permitting authorities would need to evaluate all permit applications for initial permit issuance, significant and minor permit modifications, and permit renewals for GHG issues (even if there are no applicable GHG requirements). Even after the *UARG* v. *EPA* decision, permitting authorities will continue to need to evaluate GHG issues for sources applying for a title V permit and for permit modifications and renewals for existing permits, and we do not anticipate that the decision will significantly affect the total number of such evaluations that will occur in any given year compared to the assumptions in our analysis, which as explained above, were based on the incremental costs of GHG permitting for any source. Thus, we are finalizing the burden hour assumptions as they were proposed. See NSPS proposal at 1494 and the supporting statement for the 2012 part 70 ICR renewal. Also, as discussed previously, we remain committed to collecting and analyzing additional data on costs and we may adjust the burden hour assumptions or other aspects of option 1 in a future rulemaking, if needed.

c. The Fee Pollutant Clarification

We are also finalizing the proposed addition of text within 40 CFR part 60, subpart TTTT, to clarify that the fee pollutant for operating permit purposes is GHG (as defined in 40 CFR 70.2 and 71.2). We are finalizing these provisions to add clarity to our regulations and to avoid the potential need for possible future rulemakings to adjust the title V fee regulations if any constituent of GHG, other than CO_2, becomes subject to regulation under section 111 for the first time. The proposal was to add this clarifying text to 40 CFR part 60, subparts Da, KKKK, and TTTT. The final rule adds the clarification text only to subpart TTTT because the EPA is

[563] The EPA estimated in the proposal that option 1 would result in about a 7 percent overall increase in the annual part 70 fees that are collected by all permitting authorities nationally. See 79 FR 1494.

[564] The EPA does not, however, read the *UARG* decision to affect other grounds on which a Title V permit may be required or the applicable requirements that must be addressed in Title V permits. *See* Memorandum from Janet G. McCabe, Acting Assistant Administrator, Office of Air and Radiation, and Cynthia Giles, Assistant Administrator, Office of Enforcement and Compliance Assurance, to Regional Administrators, Regions 1–10, *Next Steps and Preliminary Views on the Application of Clean Air Act Permitting Programs to Greenhouse Gases Following the Supreme Court's Decision in Utility Regulatory Group* v. *Environmental Protection Agency* (July 24, 2014) at 5.

codifying all of the requirements for the affected EGUs in a new subpart TTTT and including all CO_2 emission standards for the affected EGUs (electric utility steam generating units, as well as natural gas-fired stationary combustion turbines) in that newly created subpart. See Section III.B of this preamble for more on this subject.

d. The GHG Clarification

The EPA is taking no action at this time on the proposal to move the definitions of ''Greenhouse gases (GHG)'' within the definition of ''Subject to regulation'' in 40 CFR parts 70 and 71. No public comments were received on this proposed clarification; however, subsequent to the proposal, on June 23, 2014, the Supreme Court in *UARG* v. *EPA* decided that GHG emissions could not be used in making certain applicability determinations under the operating permit rules. More specifically with respect to title V, as described above, the Supreme Court said that the EPA may not treat GHGs as an air pollutant for purposes of determining whether a source is a major source required to obtain a title V operating permit. In accordance with the Supreme Court decision, on April 10, 2015, the D.C. Circuit issued an amended judgment in *Coalition for Responsible Regulation, Inc.* v. *Environmental Protection Agency,* Nos. 09–1322, 10–073, 10–1092 and 10–1167 (D.C. Cir. April 10, 2015), which, among other things, vacated the title V regulations under review in that case to the extent that they require a stationary source to obtain a title V permit solely because the source emits or has the potential to emit GHGs above the applicable major source thresholds. The D.C. Circuit also directed the EPA to consider whether any further revisions to its regulations are appropriate in light of *UARG* v. *EPA,* and, if so, to undertake to make such revisions.

In response to the Supreme Court decision and the D.C. Circuit's amended judgment, the EPA intends to conduct future rulemaking action to make the appropriate revisions to the operating permit rules. As part of any such future rulemaking action, the EPA may consider finalizing the proposal to move the definitions of GHGs within the operating permit rules.

F. Interactions With Other EPA Rules

Fossil fuel-fired EGUs are, or potentially will be, impacted by several other recently finalized or proposed EPA rules.[565] Many of the rules that impact fossil fuel-fired EGUs apply to existing facilities as well as newly constructed, modified, or reconstructed facilities. In fact, the rules described below are more applicable to existing EGUs than to newly constructed, modified, or reconstructed EGUs. Although those rules will affect EGUs as existing sources, because we expect that there will be few NSPS modifications or reconstructions, we don't anticipate those rules affecting EGUs as modified or reconstructed sources. In constructing new EGUs, sources can take all applicable requirements of the various rules into consideration.

1. Mercury and Air Toxics Standards (MATS)

On February 16, 2012, the EPA issued the MATS rule (77 FR 9304) to reduce emissions of toxic air pollutants from new and existing coal- and oil-fired EGUs. The MATS rule will reduce emissions of heavy metals, including mercury (Hg), arsenic (As), chromium (Cr), and nickel (Ni); and acid gases, including hydrochloric acid (HCl) and hydrofluoric acid (HF). These toxic air pollutants, also known as hazardous air pollutants or air toxics, are known to cause, or suspected of causing, damage nervous system damage, cancer, and other serious health effects. The MATS rule will also reduce SO_2 and fine particle pollution, which will reduce particle concentrations in the air and prevent thousands of premature deaths and tens of thousands of heart attacks, bronchitis cases and asthma episodes.

New or reconstructed EGUs (*i.e.,* sources that commence construction or reconstruction after May 3, 2011) subject to the MATS rule are required to comply by April 16, 2012 or upon startup, whichever is later.

Existing sources subject to the MATS rule were required to begin meeting the rule's requirements on April 16, 2015. Controls that will achieve the MATS performance standards are being installed on many units. Certain units, especially those that operate infrequently, may be considered not worth investing in given today's electricity market, and are closing. The final MATS rule provided a foundation on which states and other permitting authorities could rely in granting an additional, fourth year for compliance provided for by the CAA. States report that these fourth year extensions are being granted. In addition, the EPA issued an enforcement policy that provides a clear pathway for reliability-critical units to receive an administrative order that includes a compliance schedule of up to an additional year, if it is needed to ensure electricity reliability.[566]

2. Cross-State Air Pollution Rule (CSAPR)

The CSAPR requires states to take action to improve air quality by reducing SO_2 and NO_X emissions that cross state lines. These pollutants react in the atmosphere to form fine particles and ground-level ozone and are transported long distances, making it difficult for other states to attain and maintain the NAAQS. The first phase of CSAPR became effective on January 1, 2015, for SO_2 and annual NO_X, and May 1, 2015, for ozone season NO_X. The second phase will become effective on January 1, 2017, for SO_2 and annual NO_X, and May 1, 2017, for ozone season NO_X. Many of the power plants participating in CSAPR have taken actions to reduce hazardous air pollutants for MATS compliance that will also reduce SO_2 and/or NO_X. In this way these two rules are complementary. Compliance with one helps facilities comply with the other.

3. Requirements for Cooling Water Intake Structures at Power Plants (316(b) Rule)

On May 19, 2014, the EPA issued a final rule under section 316(b) of the Clean Water Act (33 U.S. Code section 1326(b)) (referred to hereinafter as the 316(b) rule.) The rule was published on August 15, 2014 (79 FR 48300; August 15, 2014), and became effective October 14, 2014. The 316(b) rule establishes new standards to reduce injury and death of fish and other aquatic life caused by cooling water intake structures at existing power plants and manufacturing facilities.[567] The 316(b)

[565] We discuss other rulemakings solely for background purposes. The effort to coordinate rulemakings is not a defense to a violation of the CAA. Sources cannot defer compliance with existing requirements because of other upcoming regulations.

[566] Following promulgation of the MATS rule, industry, states and environmental organizations challenged many aspects of the EPA's threshold determination that regulation of EGUs is ''appropriate and necessary'' and the final standards regulating hazardous air pollutants from EGUs. The U.S. Court of Appeals for the D.C. Circuit upheld all aspects of the MATS rule. *White Stallion Energy Center* v. *EPA,* 748 F.3d 1222 (D.C. Cir. 2014). The decision was unanimous on all issues except a dissent was filed because the EPA did not consider cost when determining regulation of EGUs is appropriate. In *Michigan* v. *EPA,* case no. 14–46, the Supreme Court reversed the D.C. Circuit decision upholding the MATS rule finding that EPA erred by not considering cost when determining that regulation of EGUs was ''appropriate'' pursuant to section 112(n)(1). The Supreme Court considered only the narrow question of cost and did not review the other holdings of the D.C. Circuit, nor did the Supreme Court vacate the MATS rule.

[567] CWA section 316(b) provides that standards applicable to point sources under sections 301 and

rule subjects existing power plants and manufacturing facilities that withdraw in excess of 2 million gallons per day (MGD) of cooling water, and use at least 25 percent of that water for cooling purposes, to a national standard designed to reduce the number of fish destroyed through impingement and entrainment. Existing sources subject to the 316(b) rule are required to comply with the impingement requirements as soon as practicable after the entrainment requirements are determined. They must comply with applicable site-specific entrainment reduction controls based on the schedule of requirements established by the permitting authority. Additional information regarding the 316(b) rule for existing sources is included in Section IX.C of the preamble to the CAA section 111(d) emission guidelines for existing EGUs that the EPA is finalizing simultaneously with this rule. Although the recently issued 316(b) rule discussed here applies to existing sources, there are also 316(b) technology-based standards for new sources with cooling water intake structures.

4. Disposal of Coal Combustion Residuals From Electric Utilities (CCR Rule)

On December 19, 2014, the EPA issued the final rule for the disposal of coal combustion residuals from electric utilities. The rule provides a comprehensive set of requirements for the safe disposal of coal combustion residuals (CCRs), commonly known as coal ash, from coal-fired power plants. The CCR rule establishes technical requirements for existing and new CCR landfills and surface impoundments under Subtitle D of the Resource Conservation and Recovery Act (RCRA), the nation's primary law for regulating solid waste. New CCR landfills and surface impoundments are required to meet the technical criteria before any CCR is placed into the unit. Existing CCR surface impoundments and landfills are subject to implementation timeframes established in the rule for the individual technical criteria. For additional information regarding the CCR rule, see Section IX.C of the preamble to the CAA section 111(d) emission guidelines for existing EGUs that the EPA is finalizing along with this rule.

5. Steam Electric Effluent Limitation Guidelines and Standards (SE ELG Rule)

The EPA is reviewing public comments and working to finalize the proposed SE ELG rule which will impact fossil fuel-fired EGUs. In 2013, the EPA proposed the SE ELG rule (78 FR 34432; June 7, 2013) to strengthen the controls on discharges from certain steam electric power plants by revising technology-based effluent limitations guidelines and standards for the steam electric power generating point source category. The proposed regulation, which includes new requirements for both existing and new generating units, would reduce impacts to human health and the environment by reducing the amount of toxic metals and other pollutants currently discharged to surface waters from power plants. The EPA intends to take final action on the proposed rule by September 30, 2015. Section IX.C of the preamble to the CAA section 111(d) emission guidelines for existing EGUs that the EPA is finalizing simultaneously with this rule includes additional information regarding the SE ELG rule.

The EPA recognizes the importance of assuring that each of the rules described above can achieve its intended environmental objectives in a commonsense, cost-effective manner, consistent with underlying statutory requirements, and while assuring a reliable power system. Executive Order (E.O.) 13563, ''Improving Regulation and Regulatory Review,'' issued on January 18, 2011, states that ''[i]n developing regulatory actions and identifying appropriate approaches, each agency shall attempt to promote . . . coordination, simplification, and harmonization.'' E.O. 13563 further states that ''[e]ach agency shall also seek to identify, as appropriate, means to achieve regulatory goals that are designed to promote innovation.'' Within the EPA, we are paying careful attention to the interrelatedness and potential impacts on the industry, reliability and cost that these various rulemakings can have.

As discussed in earlier sections of this preamble, the EPA has identified potential alternative compliance pathways for affected newly constructed, modified, and reconstructed fossil fuel-fired steam generating units. We are finalizing an emission standard for newly constructed highly efficient fossil fuel-fired steam generating units that can be met by capturing and storing approximately 16 to 23 percent of the CO_2 produced from the facility or by utilizing other technologies such as natural gas co-firing. For a subcategory of steam generating units that conduct ''large'' modifications according to definitions in this final rule, we are finalizing an emission standard that is based on a unit-specific emission limitation consistent with each modified unit's best one-year historical performance and can be met through a combination of best operating practices and equipment upgrades. For reconstructed steam generating units, the EPA is finalizing standards of performance based on the performance of the most efficient generation technology available, which we concluded is the use of the best available subcritical steam conditions for small units and the use of supercritical steam conditions for large units. The standards can also be met through other technology options such as natural gas co-firing. In light of these potential alternative compliance pathways, we believe that sources will have ample opportunity to coordinate their response to this rule with any obligations that may be applicable to affected EGUs as a result of the MATS, CSAPR, 316(b), SE ELG and CCR rules, all of which are or soon will be final rules—and to do so in a manner that will help reduce cost and ensure reliability, while also ensuring that all applicable environmental requirements are met.[568]

The EPA is also endeavoring to enable EGUs to comply with applicable obligations under other power sector rules as efficiently as possible (*e.g.,* by facilitating their ability to coordinate planning and investment decisions with respect to those rules) and, where possible, implement integrated compliance strategies. Section IX.C of the preamble to the CAA section 111(d) emission guidelines for existing EGUs that the EPA is finalizing simultaneously with this rule describes such an example with respect to the SE ELG and CCR rules.

In light of the compliance flexibilities we are offering in this action, we believe that sources will have ample opportunity to use cost-effective regulatory strategies and build on their longstanding, successful records of complying with multiple CAA, CWA, and other environmental requirements, while assuring an adequate, affordable, and reliable supply of electricity.

---

306 of the Act must require that the location, design, construction and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impacts.

[568] It should be noted that regulatory obligations imposed upon states and sources operate independently under different statutes and sections of statutes; the EPA expects that states and sources will take advantage of available flexibilities as appropriate, but will comply with all relevant legal requirements.

XIII. Impacts of This Action

As explained in the ''Regulatory Impact Analysis for the Standards of Performance for Greenhouse Gas Emissions for New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units'' (EPA–452/R–15–005, August 2015) (RIA), available data indicate that, even in the absence of the standards of performance for newly constructed EGUs, existing and anticipated economic conditions will lead electricity generators to choose new generation technologies that will meet the standards without installation of additional controls. Therefore, based on the analysis presented in Chapter 4 of the RIA, the EPA projects that this final rule will result in negligible CO_2 emission changes, quantified benefits, and costs on owners and operators of newly constructed EGUs by 2022.[569] This conclusion is based on the EPA's own modeling as well as projections by EIA. While the primary conclusion of the analysis presented in the RIA is that the standards for newly constructed EGUs will result in negligible costs and benefits, the EPA has also performed several illustrative analyses that show the potential impacts of the rule if certain key assumptions were to change. This includes an analysis of the impacts under a range of natural gas prices and the costs and benefits associated with building an illustrative coal-fired EGU with CCS. These are presented in Chapter 5 of the RIA.

As also explained in the RIA for this final rule, the EPA also expects that few sources will trigger either the NSPS modification or reconstruction provisions that we are finalizing in this rule. In Chapter 6 of the RIA, we discuss factors that limit our ability to quantify the costs and benefits of the standards for modified and reconstructed sources.

A. What are the air impacts?

As explained immediately above, the EPA does not anticipate that this final rule will result in notable CO_2 emission changes by 2022 as a result of the standards of performance for newly constructed EGUs. The owners of newly constructed EGUs will likely choose technologies, primarily NGCC, which meet the standards even in the absence of this rule due to existing economic conditions as normal business practice.

As also explained immediately above, the EPA expects few EGUs to trigger the NSPS modification or reconstruction provisions in the period of analysis.

New steam generating EGUs that choose to comply with the final standard of performance by implementing partial post-combustion CCS are likely to use commercially-available amine-based capture systems. Some concern has been raised regarding emissions of amines and amine degradation by-products (*e.g.,* NH_3) from the capture process. To reduce the amine emissions, MHI introduced the first optimized washing system within an absorber column in 1994, and developed a proprietary washing system in 2003. In that system, a proprietary reagent is added to the water washing section to capture amine impurities such as amine, degraded amine, ammonia, formaldehyde, acetaldehyde, carbonic acids and nitrosamines.[570] MHI has continued to improve this technology for further reduction of amine emissions and established an ''advanced amine emission reduction system''.

Research performed by MHI at Alabama Power's Plant Barry indicated that an increasing SO_3 content in the flue gas caused a significant increase of amine emissions. During testing, at Plant Barry, MHI applied its proprietary washing system and confirmed that the amine emission were drastically reduced.[571] Others have also studied emissions and control strategies and have determined that a conventional multi-stage water wash and mist eliminator at the exit of the CO_2 scrubber is effective at removal of gaseous amine and amine degradation products emissions.[572] [573] Additional research continues in this area.

B. Endangered Species Act

Consistent with the requirements of section 7(a)(2) of the Endangered Species Act (ESA), the EPA has also considered the effects of this rule and has reviewed applicable ESA regulations, case law, and guidance to determine what, if any, impact there may be to listed endangered or threatened species or the designated critical habitat of such species and whether consultation with the U.S. Fish and Wildlife Service (FWS) and/or National Marine Fisheries Service (together, the Services) is required by the ESA. Section 7(a)(2) of the ESA requires federal agencies, in consultation with the Service(s), to ensure that actions they authorize, fund, or carry out are not likely to jeopardize the continued existence of federally listed endangered or threatened species or result in the destruction or adverse modification of designated critical habitat of such species. 16 U.S.C. 1536(a)(2). Under relevant implementing regulations, ESA section 7(a)(2) applies only to actions where there is discretionary federal involvement or control. 50 CFR 402.03. Further, under the regulations consultation is required only for actions that ''may affect'' listed species or designated critical habitat. 50 CFR 402.14. Consultation is not required where the action has no effect on such species or habitat. Under this standard, it is the federal agency taking the action that evaluates the action and determines whether consultation is required. *See* 51 FR 19926, 19949 (June 3, 1986). Effects of an action include both the direct and indirect effects that will be added to the environmental baseline. 50 CFR 402.02. Direct effects are the direct or immediate effects of an action on a listed species or its habitat.[574] Indirect effects are those that are ''caused by the proposed action and are later in time, but still are reasonably certain to occur.'' *Id.* To trigger the consultation requirement, there must thus be a causal connection between the federal action, the effect in question, and the listed species, and if the effect is indirect, it must be reasonably certain to occur.

The EPA notes that the projected environmental effects of this final action are positive: Reductions in overall GHG emissions, and reductions in PM and ozone-precursor emissions (SO_X and NO_X). The EPA recognizes that beneficial effects to listed species can, as a general matter, result in a ''may affect'' determination under the ESA. However, the EPA's assessment that the rule will have an overall net positive environmental effect by virtue of reducing emissions of certain air pollutants does not address whether the rule may affect any listed species or designated critical habitat for ESA section 7(a)(2) purposes and does not constitute any finding of effects for that purpose. The fact that the rule will have overall positive effects on the national

[569] Conditions in the analysis year of 2022 are represented by a model year of 2020.

[570] Sharma, S.; Azzi, M.; ''A critical review of existing strategies for emission control in the monoethanolamine-based carbon capture process and some recommendations for improved strategies'', *Fuel,* 121, 178 (2014).

[571] Kamijo, T.; et al., ''SO_3 Impact on Amine Emission and Emission Reduction Technology'', *Energy Procedia,* Volume 37, 1793 (2013).

[572] Sharma, S. (2014).

[573] Mertens, J.; et al., ''Understanding ethanolamine (MEA) and ammonia emissions from amine based post combustion carbon capture: Lessons learned from field tests'', *Int'l J. of GHG Control,* 13, 72 (2013).

[574] *See* Endangered Species Consultation Handbook, U.S. Fish & Wildlife Service and National Marine Fisheries Service at 4–25(March 1998) (providing examples of direct effects: *e.g.,* driving an off road vehicle through the nesting habitat of a listed species of bird and destroying a ground nest; building a housing unit and destroying the habitat of a listed species).

and global environment does not mean that the rule may affect any listed species in its habitat or the designated critical habitat of such species within the meaning of ESA section 7(a)(2) or the implementing regulations or require ESA consultation.

The EPA notes that the emission reductions achieved by the rule are projected to be minor. See Section XIII.F and G. below, and RIA chapter 4. Although the final rule imposes substantial controls on CO_2 emissions, we project few if any new fossil fuel-fired steam generating units to be built. Emissions reductions from turbines are likewise projected to be minimal. Moreover, we reasonably project that capacity additions during the analysis period out to 2022 would already be compliant with the rule's requirements (*e.g.,* natural gas combined cycle units, low capacity factor natural gas combustion turbines, and small amounts of coal-fired units with CCS supported by federal and state funding). See RIA chapter 4.

With respect to the projected GHG emission reductions, the EPA does not believe that such minor reductions trigger ESA consultation requirements under section 7(a)(2). In reaching this conclusion, the EPA is mindful of significant legal and technical analysis undertaken by FWS and the U.S. Department of the Interior (DOI) in the context of listing the polar bear as a threatened species under the ESA. In that context, in 2008, FWS and DOI expressed the view that the best scientific data available were insufficient to draw a causal connection between GHG emissions and effects on the species in its habitat.[575] The DOI Solicitor concluded that where the effect at issue is climate change, proposed actions involving GHG emissions cannot pass the ''may affect'' test of the section 7 regulations and thus are not subject to ESA consultation.

The EPA has also previously considered issues relating to GHG emissions in connection with the requirements of ESA section 7(a)(2) and has supplemented DOI's analysis with additional consideration of GHG modeling tools and data regarding listed species. The EPA evaluated this same issue in the context of the light duty vehicle GHG emission standards for model years 2012–2016 and 2017–2025. There the agency projected GHG emission reductions many orders of magnitude greater over the lifetimes of the model years in question[576] and, based on air quality modeling of potential environmental effects, concluded that ''EPA knows of no modeling tool which can link these small, time-attenuated changes in global metrics to particular effects on listed species in particular areas. Extrapolating from global metric to local effect with such small numbers, and accounting for further links in a causative chain, remain beyond current modeling capabilities.'' EPA, *Light Duty Vehicle Greenhouse Gas Standards and Corporate Average Fuel Economy Standards,* Response to Comment Document for Joint Rulemaking at 4–102 (Docket EPA–OAR–HQ–2009–4782). The EPA reached this conclusion after evaluating issues relating to potential improvements relevant to both temperature and oceanographic pH outputs. The EPA's ultimate finding was that ''any potential for a specific impact on listed species in their habitats associated with these very small changes in average global temperature and ocean pH is too remote to trigger the threshold for ESA section 7(a)(2).'' *Id.* The EPA believes that the same conclusions apply to the present action, given that the projected CO_2 emission reductions are *far* less than those projected for either of the light duty vehicle rules. *See, e.g., Ground Zero Center for Non-Violent Action* v. *U.S. Dept. of Navy,* 383 F. 3d 1082, 1091–92 (9th Cir. 2004) (where the likelihood of jeopardy to a species from a federal action is extremely remote, ESA does not require consultation). The EPA's conclusion is entirely consistent with DOI's analysis regarding ESA requirements in the context of federal actions involving GHG emissions.[577]

The EPA received a comment on the proposal referencing a prior letter sent to the EPA by three U.S. Senators,[578] which asserted that the rule will cause a shift to alternative sources of energy such as wind and solar and that such facilities may have impacts on listed species. The comment inquired regarding ESA consultation in connection with the rule. We reiterate that no consultation is required for a rule without potential for a specific impact on listed species in their habitats.

C. What are the energy impacts?

This final rule is not anticipated to have a notable effect on the supply, distribution, or use of energy. As previously stated, the EPA believes that electric power companies will choose to build new EGUs that comply with the regulatory requirements of this rule even in its absence, primarily NGCC units, because of existing and expected market conditions. As also previously stated, the EPA expects few EGUs to trigger the NSPS modification or reconstruction provisions in the period of analysis.

D. What are the water and solid waste impacts?

This final rule is not anticipated to have notable impacts on water or solid waste. As we have noted, the EPA believes that utilities and project developers will choose to build new EGUs that comply with the regulatory requirements of this rule even in its absence, primarily through the construction of new NGCC units. As also previously stated, the EPA expects few EGUs to trigger the NSPS modification or reconstruction provisions in the period of analysis. Still there are expected to be a small number of coal plants with CCS and the use of CCS systems (especially post-combustion system) will increase the amount of water used at the facility. If those plants utilize partial CCS to meet the final standard of performance (*i.e.,* approximately 16 to 23 percent capture), the increased water use will not be significant. See Section V.O.2. The EPA is unaware of any solid waste impact resulting from this rule.[579]

E. What are the compliance costs?

For steam generating EGUs, the EPA has carefully analyzed the costs of meeting the promulgated standard of performance for a highly efficient SCPC

[575] *See, e.g.,* 73 FR 28212, 28300 (May 15, 2008); Memorandum from David Longly Bernhardt, Solicitor, U.S. Department of the Interior re: ''Guidance on the Applicability of the Endangered Species Act's Consultation Requirements to Proposed Actions Involving the Emission of Greenhouse Gases'' (Oct. 3, 2008).

[576] *See* 75 FR at 25438 Table I.C 2–4 (May 7, 2010); 77 FR at 62894 Table III–68 (Oct. 15, 2012).

[577] The EPA has received correspondence from Members of Congress asserting that the Services have identified several listed species affected by global climate change. The EPA's assessment of ESA requirements in connection with the present rule does not address whether global climate change may, as a general matter, be a relevant consideration in the status of certain listed species. Rather, the requirements of ESA section 7(a)(2) must be considered and applied to the specific action at issue. As explained above, the EPA's conclusion that ESA section 7(a)(2) consultation is not required here is premised on the specific facts and circumstances of the present rule and is fully consistent with prior relevant analyses conducted by DOI, FWS, and the EPA.

[578] *See* Letter from David Vitter, James M. Inhofe, and Mike Crapo, United States Senate Committee on Environment and Public Works, to Gina McCarthy, Administrator, U.S. Environmental Protection Agency, and Dan Ashe, Director, U.S. Fish and Wildlife Service, dated March 6, 2014.

[579] Estimated costs for the rule include costs for fly ash and bottom ash disposal and for spent solvent recovery and handling. See ''Cost and Performance Baseline for Fossil Energy Plants Volume 1a: Bituminous Coal (PC) and Natural Gas to Electricity, Revision 3'', DOE/NETL–2015/1723 (July 2015) at pp. 43, 130.

using partial CCS and found these costs to be reasonable. See Sections V.H and I above. This analysis assumes new capacity not otherwise compliant with the standards would be constructed. Based on the analysis in chapter 4 of the RIA, the EPA believes the standards of performance for newly constructed EGUs will have no notable compliance costs, because electric power companies are expected to build new EGUs that comply with the regulatory requirements of this final rule even in the absence of the rule, primarily NGCC units, due to existing and expected market conditions. While the EPA's analysis and projections from EIA continue to show that the rule is likely to result in negligible costs and benefits due to existing generation choices, the EPA recognizes that some companies may choose to construct coal or other fossil fuel-fired units and has set standards for these units accordingly. For this reason, the RIA also analyzes project-level costs of a unit with and without CCS, to quantify the potential cost for a fossil fuel-fired unit with CCS.

In addition, the EPA believes the standards of performance for modified and reconstructed EGUs will have minimal associated compliance costs, because, as previously stated, the EPA expects few EGUs to trigger the NSPS modification or reconstruction provisions in the period of analysis.

F. What are the economic and employment impacts?

The EPA does not anticipate that this final rule will result in notable CO_2 emission changes, energy impacts, monetized benefits, costs, or economic impacts by 2022 as a result of the standards of performance for newly constructed EGUs. The owners of newly constructed EGUs will likely choose technologies that meet the standards even in the absence of this rule, due to existing economic conditions as normal business practice. Likewise, the EPA believes this rule will not have any impacts on the price of electricity, employment or labor markets, or the U.S. economy. See RIA chapter 4.6.[580]

As previously stated, the EPA anticipates few units will trigger the NSPS modification or reconstruction provisions. As with the new source standards, the EPA does not expect macroeconomic or employment impacts as a result of the standards.

[580] The employment analysis in the RIA is part of the EPA's ongoing effort to ''conduct continuing evaluations of potential loss or shifts of employment which may result from the administration or enforcement of [the Act]'' pursuant to CAA section 321(a).

G. What are the benefits of the final standards?

We are not projecting direct monetized climate benefits in terms of CO_2 emission reductions associated with these standards of performance. This is because, as stated above, the EPA believes that electric power companies will choose to build new EGUs that comply with the regulatory requirements of this rule even in its absence, primarily NGCC units, because of existing and expected market conditions. See RIA chapter 4. Moreover, a cost-reasonable standard is, in fact, what will drive new technology deployment and provide a path forward for new coal-fired capacity. See Section V.L above.

As also previously stated, the EPA anticipates few units will trigger the NSPS modification or reconstruction provisions. In Chapter 6 of the RIA, we discuss factors that limit our ability to quantify the costs and benefits of the standards for modified and reconstructed sources.

XIV. Statutory and Executive Order Reviews

Additional information about these Statutory 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 final action is a significant regulatory action that was submitted to the Office of Management and Budget (OMB) for review. It is a significant regulatory action because it raises novel legal or policy issues arising out of legal mandates. Any changes made in response to OMB recommendations have been documented in the established dockets for this action under Docket ID No. EPA–HQ–OAR–2013–0495 (Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units) and Docket ID No. EPA–HQ–OAR–2013–0603 (Carbon Pollution Standards for Modified and Reconstructed Stationary Sources: Electric Utility Generating Units). The EPA prepared an economic analysis of the potential costs and benefits associated with this action. This analysis, which is contained in the ''Regulatory Impact Analysis for the Standards of Performance for Greenhouse Gas Emissions for New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units'' (EPA–452/R–15–005, August 2015), is available in both dockets.

The EPA does not anticipate that this final action will result in any notable compliance costs. Specifically, we believe that the standards for newly constructed fossil fuel-fired EGUs (electric utility steam generating units and natural gas-fired stationary combustion turbines) will have negligible costs associated with it over a range of likely sensitivity conditions because electric power companies will choose to build new EGUs that comply with the regulatory requirements of this action even in the absence of the action, because of existing and expected market conditions. (See the RIA for further discussion of sensitivities). The EPA does not project any new coal-fired steam generating units without CCS to be built in the absence of this action. However, because some companies may choose to construct coal or other fossil fuel-fired EGUs, the RIA also analyzes project-level costs of a unit with and without CCS, to quantify the potential cost for a fossil fuel-fired EGU with CCS.

The EPA also believes that the standards for modified and reconstructed fossil fuel-fired EGUs will result in minimal compliance costs, because, as previously stated, the EPA expects few EGUs to trigger the NSPS modification or reconstruction provisions in the period of analysis (through 2022). In Chapter 6 of the RIA, we discuss factors that limit our ability to quantify the costs and benefits of the standards for modified and reconstructed sources.

B. Paperwork Reduction Act (PRA)

The information collection activities in this final action have been submitted for approval to OMB under the PRA. The Information Collection Request (ICR) document that the EPA prepared has been assigned EPA ICR number 2465.03. Separate ICR documents were prepared and submitted to OMB for the proposed standards for newly constructed EGUs (EPA ICR number 2465.02) and the proposed standards for modified and reconstructed EGUs (EPA ICR number 2506.01). Because the CO_2 standards for newly constructed, modified, and reconstructed EGUs will be included in the same new subpart (40 CFR part 60, subpart TTTT) and are being finalized in the same action, the ICR document for this action includes estimates of the information collection burden on owners and operators of newly constructed, modified, and reconstructed EGUs. Estimated cost burden is based on 2013 Bureau of Labor Statistics (BLS) labor cost data.

Thus, all burden estimates are in 2013 dollars. Burden is defined at 5 CFR 1320.3(b). You can find a copy of the ICR in the dockets for this action (Docket ID Numbers EPA–HQ–OAR–2013–0495 and EPA–HQ–OAR–2013–0603), and it is briefly summarized here. The information collection requirements are not enforceable until OMB approves them.

The recordkeeping and reporting requirements in this final action 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.

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 OMB approves this ICR, the agency will announce that approval in the **Federal Register** and publish a technical amendment to 40 CFR part 9 to display the OMB control number for the approved information collection activities contained in this final action.

1. Newly Constructed EGUs

This final action will impose minimal new information collection burden on owners and operators of affected newly constructed fossil fuel-fired EGUs (steam generating units and stationary combustion turbines) beyond what those sources would already be subject to under the authorities of CAA parts 75 and 98. OMB has previously approved the information collection requirements contained in the existing part 75 and 98 regulations (40 CFR part 75 and 40 CFR part 98) under the provisions of the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.* and has assigned OMB control numbers 2060–0626 and 2060–0629, respectively. Apart from certain reporting costs to comply with the emission standards under the rule, there are no new information collection costs, as the information required by the standards for newly constructed EGUs is already collected and reported by other regulatory programs.

The EPA believes that electric power companies will choose to build new EGUs that comply with the regulatory requirements of the rule because of existing and expected market conditions. The EPA does not project any newly constructed coal-fired steam generating units that commenced construction after proposal (January 8, 2014) to commence operation over the 3-year period covered by this ICR. We estimate that 12 affected newly constructed NGCC units and 25 affected newly constructed natural gas-fired simple cycle combustion turbines will commence operation during that time period. As a result of this final action, owners or operators of those newly constructed units will be required to prepare a summary report, which includes reporting of emissions and downtime, every 3 months.

2. Modified and Reconstructed EGUs

This final action is not expected to impose an information collection burden under the provisions of the PRA on owners and operators of affected modified and reconstructed fossil fuel-fired EGUs (steam generating units and stationary combustion turbines). As previously stated, the EPA expects few EGUs to trigger the NSPS modification or reconstruction provisions in the period of analysis. Specifically, the EPA believes it unlikely that fossil fuel-fired electric utility steam generating units or stationary combustion turbines will take actions that would constitute modifications or reconstructions as defined under the EPA's NSPS regulations. Accordingly, the standards for modified and reconstructed EGUs are not anticipated to impose any information collection burden over the 3-year period covered by this ICR. We have estimated, however, the information collection burden that would be imposed on an affected EGU if it was modified or reconstructed.

Although not anticipated, if an EGU were to modify or reconstruct, this final action would impose minimal information collection burden on those affected EGUs beyond what they would already be subject to under the authorities of CAA 40 CFR parts 75 and 98. As described above, the OMB has previously approved the information collection requirements contained in the existing part 75 and 98 regulations. Apart from certain reporting costs to comply with the emission standards under the rule, there would be no new information collection costs, as the information required by the final rule is already collected and reported by other regulatory programs.

As stated above, although the EPA expects few sources will trigger either the NSPS modification or reconstruction provisions, if an EGU were to modify or reconstruct during the 3-year period covered by this ICR, the owner or operator of the EGU will be required to prepare a summary report, which includes reporting of emissions and downtime, every 3 months. The annual reporting burden for such a unit is estimated to be $1,333 and 16 labor hours. There are no annualized capital costs or O&M costs associated with burden for modified or reconstructed EGUs.

3. Information Collection Burden

The annual information collection burden for newly constructed, modified, and reconstructed EGUs consists only of reporting burden as explained above. The annual reporting burden for this collection (averaged over the first 3 years after the effective date of the standards) is estimated to be $60,977 and 651 labor hours. There are no annualized capital costs or O&M costs associated with burden for newly constructed, modified, or reconstructed EGUs. Average burden hours per response are estimated to be 7 hours. The total number of respondents over the 3-year ICR period is estimated to be 62.

C. Regulatory Flexibility Act (RFA)

I certify that this final 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.

1. Newly Constructed EGUs

The EPA believes that electric power companies will choose to build new fossil fuel-fired electric utility steam generating units or natural gas-fired stationary combustion turbines that comply with the regulatory requirements of the final rule because of existing and expected market conditions. RIA Chapter 4. The EPA does not project any new coal-fired steam generating units without CCS to be built. We expect that any newly constructed natural gas-fired stationary combustion turbines will meet the standards. We do not include an analysis of the illustrative impacts on small entities that may result from implementation of the final rule because we anticipate negligible compliance costs over a range of likely sensitivity conditions as a result of the standards for newly constructed EGUs. Thus the cost-to-sales ratios for any affected small entity would be zero costs as compared to annual sales revenue for the entity. Accordingly, there are no anticipated economic impacts as a result of the standards for newly constructed EGUs. (See the ''Regulatory Impact Analysis for the Standards of Performance for Greenhouse Gas Emissions for New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units'' (EPA–452/R–15–005, August 2015) for further discussion of sensitivities.) We have therefore concluded that this final action will have no net regulatory burden for all directly regulated small entities.

2. Modified and Reconstructed EGUs

The EPA expects few fossil fuel-fired electric utility steam generating units to trigger the NSPS modification provisions in the period of analysis. An NSPS modification is defined as a physical or operational change that increases the source's maximum achievable hourly rate of emissions. The EPA does not believe that there are likely to be EGUs that will take actions that would constitute modifications as defined under the EPA's NSPS regulations.

In addition, the EPA expects few reconstructed fossil fuel-fired electric utility steam generating units or natural gas-fired stationary combustion turbines in the period of analysis. Reconstruction occurs when a single project replaces components or equipment in an existing facility and exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility.

In Chapter 6 of the RIA, we discuss factors that limit our ability to quantify the costs and benefits of the standards for modified and reconstructed sources. However, we do not anticipate that the rule would impose significant costs on those sources, including any that are owned by small entities. (See the ''Regulatory Impact Analysis for the Standards of Performance for Greenhouse Gas Emissions for New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units'' (EPA–452/R–15–005, August 2015).

D. Unfunded Mandates Reform Act (UMRA)

This final 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.

The EPA believes the final rule will have negligible compliance costs on owners and operators of newly constructed EGUs over a range of likely sensitivity conditions because electric power companies will choose to build new fossil fuel-fired electric utility steam generating units or natural gas-fired stationary combustion turbines that comply with the regulatory requirements of the rule because of existing and expected market conditions. The EPA does not project any new coal-fired steam generating units without CCS to be built and expects that any newly constructed natural gas-fired stationary combustion turbines will meet the standards. (See the ''Regulatory Impact Analysis for the Standards of Performance for Greenhouse Gas Emissions for New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units'' (EPA–452/R–15–005, August 2015) for further discussion of sensitivities.)

As previously stated, the EPA expects few fossil fuel-fired electric utility steam generating units or natural gas-fired stationary combustion turbines to trigger the NSPS modification or reconstruction provisions in the period of analysis. In Chapter 6 of the RIA, we discuss factors that limit our ability to quantify the costs and benefits of the standards for modified and reconstructed sources. However, we do not anticipate that the rule would impose significant costs on those sources. (See the ''Regulatory Impact Analysis for the Standards of Performance for Greenhouse Gas Emissions for New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units'' (EPA–452/R–15–005, August 2015).)

We have therefore concluded that the standards for newly constructed, modified, and reconstructed EGUs do not impose enforceable duties on any state, local or tribal governments, or the private sector, that may result in expenditures by state, local and tribal governments, in the aggregate, or to the private sector, of $100 million or more in any one year. We have also concluded that this action does not have regulatory requirements that might significantly or uniquely affect small governments. The threshold amount established for determining whether regulatory requirements could significantly affect small governments is $100 million annually and, as stated above, we have concluded that the final action will not result in expenditures of $100 million or more in any one year. Specifically, the EPA does not project any new coal-fired steam generating units without CCS to be built and expects that any newly constructed natural gas-fired stationary combustion turbines will meet the standards. Further, the EPA expects few fossil fuel-fired electric utility steam generating units or natural gas-fired stationary combustion turbines to trigger the NSPS modification or reconstruction provisions in the period of analysis.

E. Executive Order 13132: Federalism

This final 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. The EPA believes that electric power companies will choose to build new fossil fuel-fired electric utility steam generating units or natural gas-fired stationary combustion turbines that comply with the regulatory requirements of the final rule because of existing and expected market conditions. In addition, as previously stated, the EPA expects few fossil fuel-fired electric utility steam generating units or natural gas-fired stationary combustion turbines to trigger the NSPS modification or reconstruction provisions in the period of analysis. We, therefore, anticipate that the final rule will impose minimal compliance costs.

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

This final action does not have tribal implications as specified in Executive Order 13175. The final rule will impose requirements on owners and operators of newly constructed, modified, and reconstructed EGUs. The EPA is aware of three facilities with coal-fired steam generating units, as well as one facility with natural gas-fired stationary combustion turbines, located in Indian Country, but is not aware of any EGUs owned or operated by tribal entities. We note that because the rule addresses CO_2 emissions from newly constructed, modified, and reconstructed EGUs, it will affect existing EGUs such as those located at the four facilities in Indian Country only if those EGUs were to take actions constituting modifications or reconstructions as defined under the EPA's NSPS regulations. As previously stated, the EPA expects few EGUs to trigger the NSPS modification or reconstruction provisions in the period of analysis. Thus, the rule will neither impose substantial direct compliance costs on tribal governments nor preempt Tribal law. Accordingly, Executive Order 13175 does not apply to this action.

Nevertheless, because the EPA is aware of Tribal interest in carbon pollution standards for the power sector and, consistent with the EPA Policy on Consultation and Coordination with Indian Tribes, the EPA offered consultation with tribal officials during development of this rule. Prior to the April 13, 2012 proposal (77 FR 22392), the EPA sent consultation letters to the leaders of all federally recognized tribes. Although only newly constructed, modified, and reconstructed EGUs will be affected by this action, the EPA's consultation regarded planned actions for new and existing sources. The letters provided information regarding the EPA's development of NSPS and emission guidelines for EGUs and offered consultation. A consultation/outreach meeting was held on May 23, 2011, with the Forest County Potawatomi Community, the Fond du Lac Band of Lake Superior Chippewa Reservation, and the Leech Lake Band of Ojibwe. A description of that consultation is included in the preamble to the proposed standards for new EGUs (79 FR 1501, January 8, 2014).

The EPA also offered consultation to the leaders of all federally recognized tribes after the proposed action for newly constructed EGUs was signed on September, 20, 2013. On November 1, 2013, the EPA sent letters to tribal leaders that provided information regarding the EPA's development of carbon pollution standards for new, modified, reconstructed and existing EGUs and offered consultation. No tribes requested consultation regarding the standards for newly constructed EGUs.

In addition to offering consultation, the EPA also conducted outreach to tribes during development of this rule. The EPA held a series of listening sessions prior to proposal of GHG standards for newly constructed EGUs. Tribes participated in a session on February 17, 2011, with the state agencies, as well as in a separate session with tribes on April 20, 2011. The EPA also held a series of listening sessions prior to proposal of GHG standards for modified and reconstructed EGUs and GHG emission guidelines for existing EGUs. Tribes participated in a session on September 9, 2013, together with the state agencies, as well as in a separate tribe-only session on September 26, 2013. In addition, an outreach meeting was held on September 9, 2013, with tribal representatives from some of the federally recognized tribes. The EPA also met with tribal environmental staff with the National Tribal Air Association, by teleconference, on July 25, 2013, and December 19, 2013. Additional detail regarding this stakeholder outreach is included in the preamble to the proposed emission guidelines for existing EGUs (79 FR 34830, June 18, 2014).

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. While the action is not subject to Executive Order 13045, 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.

CO_2 is a potent GHG that contributes to climate change and is emitted in significant quantities by fossil fuel-fired power plants. As stated above, the EPA believes the final rule will have negligible effects on owners and operators of newly constructed EGUs over a range of likely sensitivity conditions because electric power companies will choose to build new fossil fuel-fired electric utility steam generating units or natural gas-fired stationary combustion turbines that comply with the regulatory requirements of the rule because of existing and expected market conditions. However, the RIA also analyzes project-level costs of a unit with and without CCS, to quantify the potential cost for a fossil fuel-fired unit with CCS. RIA chapter 5. Under these scenarios, the rule would result in substantial reductions of both CO_2, and also fine particulate matter (sulfate PM 2.5) such that net quantifiable benefits exceed regulatory costs under a range of assumptions. Under these same scenarios, this rule would have a positive effect for children's health.

The assessment literature cited in the EPA's 2009 Endangerment Finding concluded that certain populations and lifestages, 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 II.A of this preamble.

H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

This final 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. See Section V.O.3 above. The EPA believes that electric power companies will choose to build new fossil fuel-fired electric utility steam generating units or natural gas-fired stationary combustion turbines that comply with the regulatory requirements of the final rule because of existing and expected market conditions. In addition, as previously stated, the EPA expects few fossil fuel-fired electric utility steam generating units or natural gas-fired stationary combustion turbines to trigger the NSPS modification or reconstruction provisions in the period of analysis. Thus, this action is not anticipated to have notable impacts on emissions, costs or energy supply decisions for the affected electric utility industry.

I. National Technology Transfer and Advancement Act (NTTAA) and 1 CFR Part 51

This final action involves technical standards. The EPA has decided to use 10 voluntary consensus standards (VCS) in the final rule.

One VCS, American National Standards Institute (ANSI) Standard C12.20, ''American National Standard for Electricity Meters—0.2 and 0.5 Accuracy Classes,'' is cited in the final rule to assure consistent monitoring of electric output. This standard establishes the physical aspects and acceptable performance criteria for 0.2 and 0.5 accuracy class electricity meters. This standard is available at *http://www.ansi.org* or by mail at American National Standards Institute (ANSI), 25 W. 43rd Street, 4th Floor, New York, NY 10036.

Six VCS, ASTM Methods D388–99, ''Standard Classification of Coals by Rank''; D396–98, ''Standard Specification for Fuel Oils''; D975–08a, ''Standard Specification for Diesel Fuel Oils''; D3699–08, ''Standard Specification for Kerosine''; D6751–11b, ''Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels''; and D7467–10, ''Standard Specification for Diesel Fuel Oil, Biodiesel Blend (B6 to B20)'' are cited in the final rule to identify the different fuel types. ASTM D388 covers the classification of coals by rank, that is, according to their degree of metamorphism, or progressive alteration, in the natural series from lignite to anthracite. ASTM D396 covers grades of fuel oil intended for use in various types of fuel-oil-burning equipment under various climatic and operating conditions. These include Grades 1 and 2 (for use in domestic and small industrial burners), Grade 4 (heavy distillate fuels or distillate/residual fuel blends used in commercial/industrial burners equipped for this viscosity range), and Grades 5 and 6 (residual fuels of increasing viscosity and boiling range, used in industrial burners). ASTM D975 covers seven grades of diesel fuel oils based on grade, sulfur content, and volatility. These grades range from *Grade No. 1–D S15* (a special-purpose, light middle distillate fuel for use in diesel engine applications requiring a fuel with 15 ppm sulfur (maximum) and higher volatility than that provided by Grade No. 2–D S15 fuel) to *Grade No. 4–D* (a heavy distillate fuel, or a blend of distillate and residual oil, for use in low- and medium-speed diesel engines in applications involving predominantly constant speed and load). ASTM D3699 covers two grades of kerosene suitable for use in critical kerosene burner applications: No. 1–K (a special low-sulfur grade kerosene suitable for use in non-flue-connected kerosene burner appliances and for use in wick-fed illuminating lamps) and No. 2–K (a regular grade kerosene suitable for use in flue-connected burner appliances and for use in wick-fed illuminating lamps). ASTM D6751 covers biodiesel (B100) Grades S15 and S500 for use as a blend component with middle distillate fuels. ASTM D7467 covers fuel blend grades of 6 to 20 volume percent biodiesel with the remainder being a light middle or middle distillate diesel fuel, collectively designated as B6 to B20. These standards are available at *http://www.astm.org* or by mail at ASTM International, 100 Barr Harbor Drive, P.O. Box CB700, West Conshohocken, PA 19428–2959.

Two VCS, American Society of Mechanical Engineers (ASME) Performance Test Codes PTC 22–2014, ''Performance Test Codes on Gas Turbines'' and PTC 46–1996, ''Performance Test Codes on Overall Plant Performance'' are cited in the final rule for their guidance on measuring the performance of stationary combustion turbines. PTC–22 provides directions and rules for conduct and report of results of thermal performance tests for open cycle simple cycle combustion turbines. The object is to determine the thermal performance of the combustion turbine when operating at test conditions, and correcting these test results to specified reference conditions. PTC 22 provides explicit procedures for the determination of the following performance results: corrected power, corrected heat rate (efficiency), corrected exhaust flow, corrected exhaust energy, and corrected exhaust temperature. Tests may be designed to satisfy different goals, including absolute performance and comparative performance. The objective of PTC 46 is to provide uniform test methods and procedures for the determination of the thermal performance and electrical output of heat-cycle electric power plants and combined heat and power units (PTC 46 is not applicable to simple cycle combustion turbines). Test results provide a measure of the performance of a power plant or thermal island at a specified cycle configuration, operating disposition and/or fixed power level, and at a unique set of base reference conditions. PTC 46 provides explicit procedures for the determination of the following performance results: corrected net power, corrected heat rate, and corrected heat input. These standards are available at *http://www.asme.org* or by mail at American Society of Mechanical Engineers (ASME), Two Park Avenue, New York, NY 10016–5990.

One VCS, International Organization for Standardization method ISO 2314:2009, ''Gas Turbines—Acceptance Tests'' is cited in the final rule for its guidance on determining performance characteristics of stationary combustion turbines. ISO 2314 specifies guidelines and procedures for preparing, conducting and reporting thermal-acceptance tests in order to determine and/or verify electrical power output, mechanical power, thermal efficiency (heat rate), turbine exhaust gas energy and/or other performance characteristics of open-cycle simple cycle combustion turbines using combustion systems supplied with gaseous and/or liquid fuels as well as closed-cycle and semi-closed-cycle simple cycle combustion turbines. It can also be applied to simple cycle combustion turbines in combined cycle power plants or in connection with other heat recovery systems. ISO 2314 includes procedures for the determination of the following performance parameters, corrected to the reference operating parameters: electrical or mechanical power output (gas power, if only gas is supplied), thermal efficiency or heat rate; and combustion turbine engine exhaust energy (optionally exhaust temperature and flow). This standard is available at *http://www.iso.org/iso/home.htm* or by mail at International Organization for Standardization (ISO), 1, ch. de la Voie-Creuse, Case postale 56, CH–1211 Geneva 20, Switzerland.

Since no EPA Methods were used, there was no need for a NTTAA search. The rule also requires use of appendices A, B, D, F and G to 40 CFR part 75 and the procedures under 40 CFR 98.33; these appendices contain standards that have already been reviewed under the NTTAA.

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

Executive Order 12898 (59 FR 7629; February 16, 1994) establishes federal executive policy on environmental justice. Its main provision directs federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations and low-income populations in the U.S. The EPA defines environmental justice as the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies. The EPA has this goal for all communities and persons across this Nation. It will be achieved when everyone enjoys the same degree of protection from environmental and health hazards and equal access to the decision-making process to have a healthy environment in which to live, learn, and work.

Leading up to this rulemaking the EPA summarized the public health and welfare effects of GHG emissions in its 2009 Endangerment Finding. As part of the Endangerment Finding, the Administrator considered climate change risks to minority or low-income populations, finding that certain parts of the population may be especially vulnerable based on their circumstances. Populations that were found to be particularly vulnerable to climate change risks include the poor, the elderly, the very young, those already in poor health, the disabled, those living alone, and/or indigenous populations dependent on one or a few resources. See Sections XIV.F and G, above, where the EPA discusses Consultation and Coordination with Tribal Governments and Protection of Children. The Administrator placed weight on the fact that certain groups, including children, the elderly, and the poor, are most vulnerable to climate-related health effects.

The record for the 2009 Endangerment Finding summarizes the strong scientific evidence in the major assessment reports by the U.S. Global Change Research Program (USGCRP), the Intergovernmental Panel on Climate Change (IPCC), and the National Research Council (NRC) of the National Academies that the potential impacts of climate change raise environmental justice issues. These reports concluded that poor communities can be especially vulnerable to climate change impacts because they tend to have more limited adaptive capacities and are more dependent on climate-sensitive resources such as local water and food supplies. In addition, Native American tribal communities possess unique vulnerabilities to climate change, particularly those impacted by degradation of natural and cultural resources within established reservation boundaries and threats to traditional subsistence lifestyles. Tribal communities whose health, economic well-being, and cultural traditions depend upon the natural environment will likely be affected by the degradation of ecosystem goods and services associated with climate change. The 2009 Endangerment Finding record also specifically noted that Southwest native cultures are especially vulnerable to water quality and availability impacts. Native Alaskan communities are already experiencing disruptive impacts, including coastal erosion and shifts in the range or abundance of wild species crucial to their livelihoods and well-being.

The most recent assessments continue to strengthen scientific understanding of climate change risks to minority and low-income populations in the United States.[581] The new assessment literature provides more detailed findings regarding these populations' vulnerabilities and projected impacts they may experience. In addition, the most recent assessment reports provides new information on how some communities of color may be uniquely vulnerable to climate change health impacts in the United States. These reports find that certain climate change related impacts—including heat waves, degraded air quality, and extreme weather events—have disproportionate effects on low-income and some communities of color, raising environmental justice concerns. Existing health disparities and other inequities in these communities increase their vulnerability to the health effects of climate change. In addition, assessment reports also find that climate change poses particular threats to health, wellbeing, and ways of life of indigenous peoples in the United States.

As the scientific literature presented above and in the Endangerment Finding illustrates, low income communities and some communities of color are especially vulnerable to the health and other adverse impacts of climate change.

The EPA believes the human health or environmental risk addressed by this final action will not have potential disproportionately high and adverse human health or environmental effects on minority, low-income or indigenous populations. The final rule limits GHG emissions from newly constructed, modified, and reconstructed fossil fuel-fired electric utility steam generating units and newly constructed and modified stationary combustion turbines by establishing national emission standards for CO_2.

The EPA has determined that the final rule will not result in disproportionately high and adverse human health or environmental effects on minority, low-income or indigenous populations because the rule is not anticipated to notably affect the level of protection provided to human health or the environment. The EPA believes that electric power companies will choose to build new fossil fuel-fired electric utility steam generating units and natural gas-fired stationary combustion turbines that comply with the regulatory requirements of the final rule because of existing and expected market conditions. The EPA does not project any new coal-fired steam generating units without CCS to be built and expects that any newly built natural gas-fired stationary combustion turbines will meet the standards. In addition, as previously stated, the EPA expects few fossil fuel-fired electric utility steam generating units or natural gas-fired stationary combustion turbines to trigger the NSPS modification or reconstruction provisions in the period of analysis. This final rule will ensure that, to whatever extent there are newly constructed, modified, and reconstructed EGUs, they will use the best performing technologies to limit emissions of CO_2.

K. Congressional Review Act (CRA)

This final 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).

XV. Withdrawal of Proposed Standards for Certain Modified Sources

In this action, as discussed above in Sections IV and VI, the EPA is issuing final standards of performance for affected fossil fuel-fired steam generating EGUs that implement modifications resulting in an increase of CO_2 emissions (in lb/hr) of more than 10 percent. In addition, the EPA is withdrawing the proposed standards of performance for emissions of carbon dioxide (CO_2) from modified fossil fuel-fired EGUs not covered by those final standards. Specifically, the EPA is withdrawing the proposed standards for fossil fuel-fired steam generating EGUs that implement modifications resulting in an increase of CO_2 emissions (in lb/hr) of less than or equal to 10 percent. A detailed rationale for the withdrawal of these proposed standards is provided in Section VI above.

The EPA is also, in this action, withdrawing proposed standards for modified stationary combustion turbines. A detailed rationale for the withdrawal of these proposed standards is provided in Section IX above.

The proposed standards for modified fossil fuel-fired EGUs that the EPA is withdrawing in this action were published in the **Federal Register** on June 18, 2014 (79 FR 34960).

---

[581] 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, 841 pp.

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, 1132 pp.

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, 688 pp.

XVI. Statutory Authority

The statutory authority for this action is provided by sections 111, 301, 302, and 307(d)(1)(C) of the CAA as amended (42 U.S.C. 7411, 7601, 7602, 7607(d)(1)(C)). This action is also subject to section 307(d) of the CAA (42 U.S.C. 7607(d)).

List of Subjects

40 CFR Part 60

Environmental protection, Administrative practice and procedure, Air pollution control, Incorporation by reference, Intergovernmental relations, Reporting and recordkeeping requirements.

40 CFR Part 70

Environmental protection, Administrative practice and procedure, Air pollution control, Intergovernmental relations, Reporting and recordkeeping requirements.

40 CFR Part 71

Environmental protection, Administrative practice and procedure, Air pollution control, Reporting and recordkeeping requirements.

40 CFR Part 98

Environmental protection, Greenhouse gases and monitoring, Reporting and recordkeeping requirements.

Dated: August 3, 2015.

Gina McCarthy,

Administrator.

For the reasons stated in the preamble, title 40, chapter I, parts 60, 70, 71, and 98 of the Code of the Federal Regulations are 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. 7401 *et seq.*

■ 2. Section 60.17 is amended by:

■ a. Redesignating paragraphs (d) through (t) as paragraphs (e) through (u) and adding paragraph (d);

■ b. In newly redesignated paragraph (g), further redesignating paragraph (g)(15) as paragraph (g)(17) and adding paragraphs (g)(15) and (16);

■ c. In newly redesignated paragraph (h), revising paragraphs (h)(37), (42), (46), (138), (187), and (190); and

■ c. In newly redesignated paragraph (m), further redesignating paragraph (m)(1) as paragraph (m)(2) and adding paragraph (m)(1).

The revisions and additions read as follows:

§ 60.17 Incorporations by reference.

* * * * *

(d) The following material is available for purchase from the American National Standards Institute (ANSI), 25 W. 43rd Street, 4th Floor, New York, NY 10036, Telephone (212) 642–4980, and is also available at the following Web site: *http://www.ansi.org.*

(1) ANSI No. C12.20–2010 American National Standard for Electricity Meters—0.2 and 0.5 Accuracy Classes (Approved August 31, 2010), IBR approved for § 60.5535(d).

(2) [Reserved]

* * * * *

(g) * * *

(15) ASME PTC 22–2014, Gas Turbines: Performance Test Codes, (Issued December 31, 2014), IBR approved for § 60.5580.

(16) ASME PTC 46–1996, Performance Test Code on Overall Plant Performance, (Issued October 15, 1997), IBR approved for § 60.5580.

* * * * *

(h) * * *

(37) ASTM D388–99 (Reapproved 2004) $^{\varepsilon 1}$ Standard Classification of Coals by Rank, IBR approved for §§ 60.41, 60.45(f), 60.41Da, 60.41b, 60.41c, 60.251, and 60.5580.

* * * * *

(42) ASTM D396–98, Standard Specification for Fuel Oils, IBR approved for §§ 60.41b, 60.41c, 60.111(b), 60.111a(b), and 60.5580.

* * * * *

(46) ASTM D975–08a, Standard Specification for Diesel Fuel Oils, IBR approved for §§ 60.41b 60.41c, and 60.5580.

* * * * *

(138) ASTM D3699–08, Standard Specification for Kerosine, including Appendix X1, (Approved September 1, 2008), IBR approved for §§ 60.41b, 60.41c, and 60.5580.

* * * * *

(187) ASTM D6751–11b, Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels, including Appendices X1 through X3, (Approved July 15, 2011), IBR approved for §§ 60.41b, 60.41c, and 60.5580.

* * * * *

(190) ASTM D7467–10, Standard Specification for Diesel Fuel Oil, Biodiesel Blend (B6 to B20), including Appendices X1 through X3, (Approved August 1, 2010), IBR approved for §§ 60.41b, 60.41c, and 60.5580.

* * * * *

(m) * * *

(1) ISO 2314:2009(E), Gas turbines–Acceptance tests, Third edition (December 15, 2009), IBR approved for § 60.5580.

* * * * *

■ 3. Part 60 is amended by adding subpart TTTT to read as follows:

Subpart TTTT—Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units

Applicability

§ 60.5508 What is the purpose of this subpart?

This subpart establishes emission standards and compliance schedules for the control of greenhouse gas (GHG) emissions from a steam generating unit, IGCC, or a stationary combustion turbine that commences construction after January 8, 2014 or commences modification or reconstruction after June 18, 2014. An affected steam generating unit, IGCC, or stationary combustion turbine shall, for the purposes of this subpart, be referred to as an affected EGU.

§ 60.5509 Am I subject to this subpart?

(a) Except as provided for in paragraph (b) of this section, the GHG standards included in this subpart apply to any steam generating unit, IGCC, or stationary combustion turbine that commenced construction after January 8, 2014 or commenced reconstruction after June 18, 2014 that meets the relevant applicability conditions in paragraphs (a)(1) and (2) of this section. The GHG standards included in this subpart also apply to any steam generating unit or IGCC that commenced modification after June 18, 2014 that meets the relevant applicability conditions in paragraphs (a)(1) and (2) of this section.

(1) Has a base load rating greater than 260 GJ/h (250 MMBtu/h) of fossil fuel (either alone or in combination with any other fuel); and

(2) Serves a generator or generators capable of selling greater than 25 MW of electricity to a utility power distribution system.

(b) You are not subject to the requirements of this subpart if your affected EGU meets any of the conditions specified in paragraphs (b)(1) through (10) of this section.

(1) Your EGU is a steam generating unit or IGCC that is currently and always has been subject to a federally enforceable permit condition limiting annual net-electric sales to no more than one-third of its potential electric output or 219,000 MWh, whichever is greater.

(2) Your EGU is capable of combusting 50 percent or more non-fossil fuel and is also subject to a federally enforceable permit condition limiting the annual capacity factor for all fossil fuels combined of 10 percent (0.10) or less.

(3) Your EGU is a combined heat and power unit that is subject to a federally enforceable permit condition limiting annual net-electric sales to no more than either 219,000 MWh or the product of the design efficiency and the potential electric output, whichever is greater.

(4) Your EGU serves a generator along with other steam generating unit(s), IGCC, or stationary combustion turbine(s) where the effective generation capacity (determined based on a prorated output of the base load rating of each steam generating unit, IGCC, or stationary combustion turbine) is 25 MW or less.

(5) Your EGU is a municipal waste combustor that is subject to subpart Eb of this part.

(6) Your EGU is a commercial or industrial solid waste incineration unit that is subject to subpart CCCC of this part.

(7) Your EGU is a steam generating unit or IGCC that undergoes a modification resulting in an hourly increase in CO_2 emissions (mass per hour) of 10 percent or less (2 significant figures). Modified units that are not subject to the requirements of this subpart pursuant to this subsection continue to be existing units under section 111 with respect to CO_2 emissions standards.

(8) Your EGU is a stationary combustion turbine that is not capable of combusting natural gas (*e.g.,* not connected to a natural gas pipeline).

(9) The proposed Washington County EGU project described in Air Quality Permit No. 4911–303–0051–P–01–0 issued by the Georgia Department of Natural Resources, Environmental Protection Division, Air Protection Branch, effective April 8, 2010, provided that construction had not commenced for NSPS purposes as of January 8, 2014.

(10) The proposed Holcomb EGU project described in Air Emission Source Construction Permit 0550023 issued by the Kansas Department of Health and Environment, Division of Environment, effective December 16, 2010, provided that construction had not commenced for NSPS purposes as of January 8, 2014.

Emission Standards

§ 60.5515 Which pollutants are regulated by this subpart?

(a) The pollutants regulated by this subpart are greenhouse gases. The greenhouse gas standard in this subpart is in the form of a limitation on emission of carbon dioxide.

(b) *PSD and title V thresholds for greenhouse gases.* (1) For the purposes of 40 CFR 51.166(b)(49)(ii), with respect to GHG emissions from affected facilities, the ''pollutant that is subject to the standard promulgated under section 111 of the Act'' shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in § 51.166(b)(48) of this chapter and in any SIP approved by the EPA that is interpreted to incorporate, or specifically incorporates, § 51.166(b)(48).

(2) For the purposes of 40 CFR 52.21(b)(50)(ii), with respect to GHG emissions from affected facilities, the ''pollutant that is subject to the standard promulgated under section 111 of the Act'' shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in § 52.21(b)(49) of this chapter.

(3) For the purposes of 40 CFR 70.2, with respect to greenhouse gas emissions from affected facilities, the ''pollutant that is subject to any standard promulgated under section 111 of the Act'' shall be considered to be the pollutant that otherwise is ''subject to regulation'' as defined in 40 CFR 70.2.

(4) For the purposes of 40 CFR 71.2, with respect to greenhouse gas emissions from affected facilities, the ''pollutant that is subject to any standard promulgated under section 111 of the Act'' shall be considered to be the pollutant that otherwise is ''subject to regulation'' as defined in 40 CFR 71.2.

§ 60.5520 What CO_2 emission standard must I meet?

(a) For each affected EGU subject to this subpart, you must not discharge from the affected EGU any gases that contain CO_2 in excess of the applicable CO_2 emission standard specified in Table 1 or 2 of this subpart, consistent with paragraphs (b), (c), and (d) of this section, as applicable.

(b) Except as specified in paragraphs (c) and (d) of this section, you must comply with the applicable gross energy output standard, and your operating permit must include monitoring, recordkeeping, and reporting methodologies based on the applicable gross energy output standard. For the remainder of this subpart (for sources that do not qualify under paragraphs (c) and (d) of this section), where the term ''gross or net energy output'' is used, the term that applies to you is ''gross energy output.''

(c) As an alternate to meeting the requirements in paragraph (b) of this section, an owner or operator of a stationary combustion turbine may petition the Administrator in writing to comply with the alternate applicable net energy output standard. If the Administrator grants the petition, beginning on the date the Administrator grants the petition, the affected EGU must comply with the applicable net energy output-based standard included in this subpart. Your operating permit must include monitoring, recordkeeping, and reporting methodologies based on the applicable net energy output standard. For the remainder of this subpart, where the term ''gross or net energy output'' is used, the term that applies to you is ''net energy output.'' Owners or operators complying with the net output-based standard must petition the Administrator to switch back to complying with the gross energy output-based standard.

(d) Stationary combustion turbines subject to a heat input-based standard in Table 2 of this subpart that are only permitted to burn one or more uniform fuels, as described in paragraph (d)(1) of this section, are only subject to the monitoring requirements in paragraph (d)(1). All other stationary combustion turbines subject to a heat input based standard in Table 2 are subject to the requirements in paragraph (d)(2) of this section.

(1) Stationary combustion turbines that are only permitted to burn fuels with a consistent chemical composition (*i.e.,* uniform fuels) that result in a consistent emission rate of 160 lb CO_2/MMBtu or less are not subject to any monitoring or reporting requirements under this subpart. These fuels include, but are not limited to, natural gas, methane, butane, butylene, ethane, ethylene, propane, naphtha, propylene, jet fuel kerosene, No. 1 fuel oil, No. 2 fuel oil, and biodiesel. Stationary combustion turbines qualifying under this paragraph are only required to maintain purchase records for permitted fuels.

(2) Stationary combustion turbines permitted to burn fuels that do not have a consistent chemical composition or that do not have an emission rate of 160 lb CO_2/MMBtu or less (*e.g.,* non-uniform fuels such as residual oil and non-jet fuel kerosene) must follow the monitoring, recordkeeping, and reporting requirements necessary to complete the heat input-based calculations under this subpart.

General Compliance Requirements

§ 60.5525 What are my general requirements for complying with this subpart?

Combustion turbines qualifying under § 60.5520(d)(1) are not subject to any requirements in this section other than the requirement to maintain fuel purchase records for permitted fuel(s). For all other affected sources, compliance with the applicable CO_2 emission standard of this subpart shall be determined on a 12-operating-month rolling average basis. See Table 1 or 2 of this subpart for the applicable CO_2 emission standards.

(a) You must be in compliance with the emission standards in this subpart that apply to your affected EGU at all times. However, you must determine compliance with the emission standards only at the end of the applicable operating month, as provided in paragraph (a)(1) of this section.

(1) For each affected EGU subject to a CO_2 emissions standard based on a 12-operating-month rolling average, you must determine compliance monthly by calculating the average CO_2 emissions rate for the affected EGU at the end of the initial and each subsequent 12-operating-month period.

(2) Consistent with § 60.5520(d)(2), if your affected stationary combustion turbine is subject to an input-based CO_2 emissions standard, you must determine the total heat input in million Btus (MMBtu) from natural gas ($HTIP_{ng}$) and the total heat input from all other fuels combined ($HTIP_o$) using one of the methods under § 60.5535(d)(2). You must then use the following equation to determine the applicable emissions standard during the compliance period:

$$CO_2 \text{ emission standard} = \frac{(120 \text{ x } HTIP_{ng}) + (160 \text{ x } HTIP_o)}{HTIP_{ng} + HTIP_o} \quad \text{(Eq. 1)}$$

Where:

CO_2 emission standard = the emission standard during the compliance period in units of lb/MMBtu.
$HTIP_{ng}$ = the heat input in MMBtu from natural gas.
$HTIP_o$ = the heat input in MMBtu from all fuels other than natural gas.
120 = allowable emission rate in lb of CO_2/MMBtu for heat input derived from natural gas.
160 = allowable emission rate in lb of CO_2/MMBtu for heat input derived from all fuels other than natural gas.

(b) At all times you must operate and maintain each affected EGU, including associated equipment and monitors, in a manner consistent with safety and good air pollution control practice. The Administrator will determine if you are using consistent operation and maintenance procedures based on information available to the Administrator that may include, but is not limited to, fuel use records, monitoring results, review of operation and maintenance procedures and records, review of reports required by this subpart, and inspection of the EGU.

(c) Within 30 days after the end of the initial compliance period (*i.e.,* no more than 30 days after the first 12-operating-month compliance period), you must make an initial compliance determination for your affected EGU(s) with respect to the applicable emissions standard in Table 1 or 2 of this subpart, in accordance with the requirements in this subpart. The first operating month included in the initial 12-operating-month compliance period shall be determined as follows:

(1) For an affected EGU that commences commercial operation (as defined in § 72.2 of this chapter) on or after October 23, 2015, the first month of the initial compliance period shall be the first operating month (as defined in § 60.5580) after the calendar month in which emissions reporting is required to begin under:

(i) Section 63.5555(c)(3)(i), for units subject to the Acid Rain Program; or

(ii) Section 63.5555(c)(3)(ii)(A), for units that are not in the Acid Rain Program.

(2) For an affected EGU that has commenced COMMERCIAL operation (as defined in § 72.2 of this chapter) prior to October 23, 2015:

(i) If the date on which emissions reporting is required to begin under § 75.64(a) of this chapter has passed prior to October 23, 2015, emissions reporting shall begin according to § 63.5555(c)(3)(i) (for Acid Rain program units), or according to § 63.5555(c)(3)(ii)(B) (for units that are not subject to the Acid Rain Program). The first month of the initial compliance period shall be the first operating month (as defined in § 60.5580) after the calendar month in which the rule becomes effective; or

(ii) If the date on which emissions reporting is required to begin under § 75.64(a) of this chapter occurs on or after October 23, 2015, then the first month of the initial compliance period shall be the first operating month (as defined in § 60.5580) after the calendar month in which emissions reporting is required to begin under § 63.5555(c)(3)(ii)(A).

(3) For a modified or reconstructed EGU that becomes subject to this subpart, the first month of the initial compliance period shall be the first operating month (as defined in § 60.5580) after the calendar month in which emissions reporting is required to begin under § 63.5555(c)(3)(iii).

Monitoring and Compliance Determination Procedures

§ 60.5535 How do I monitor and collect data to demonstrate compliance?

(a) Combustion turbines qualifying under § 60.5520(d)(1) are not subject to any requirements in this section other than the requirement to maintain fuel purchase records for permitted fuel(s). If your combustion turbine uses non-uniform fuels as specified under § 60.5520(d)(2), you must monitor heat input in accordance with paragraph (c)(1) of this section, and you must monitor CO_2 emissions in accordance with either paragraph (b), (c)(2), or (c)(5) of this section. For all other affected sources, you must prepare a monitoring plan to quantify the hourly CO_2 mass emission rate (tons/h), in accordance with the applicable provisions in § 75.53(g) and (h) of this chapter. The electronic portion of the monitoring plan must be submitted using the ECMPS Client Tool and must be in place prior to reporting emissions data and/or the results of monitoring system certification tests under this subpart. The monitoring plan must be updated as necessary. Monitoring plan submittals must be made by the Designated Representative (DR), the Alternate DR, or a delegated agent of the DR (see § 60.5555(c)).

(b) You must determine the hourly CO_2 mass emissions in kilograms (kg) from your affected EGU(s) according to paragraphs (b)(1) through (5) of this section, or, if applicable, as provided in paragraph (c) of this section.

(1) For an affected coal-fired EGU or for an IGCC unit you must, and for all other affected EGUs you may, install, certify, operate, maintain, and calibrate a CO_2 continuous emission monitoring system (CEMS) to directly measure and record hourly average CO_2 concentrations in the affected EGU exhaust gases emitted to the atmosphere, and a flow monitoring system to measure hourly average stack gas flow rates, according to § 75.10(a)(3)(i) of this chapter. As an alternative to direct measurement of CO_2 concentration, provided that your EGU does not use carbon separation (*e.g.,* carbon capture and storage), you may use data from a certified oxygen (O_2) monitor to calculate hourly average CO_2 concentrations, in accordance with § 75.10(a)(3)(iii) of this chapter. If you measure CO_2 concentration on a dry basis, you must also install, certify, operate, maintain, and calibrate a continuous moisture monitoring system, according to § 75.11(b) of this chapter. Alternatively, you may either use an appropriate fuel-specific default moisture value from § 75.11(b) or submit a petition to the Administrator under § 75.66 of this chapter for a site-specific default moisture value.

(2) For each continuous monitoring system that you use to determine the CO_2 mass emissions, you must meet the applicable certification and quality assurance procedures in § 75.20 of this chapter and appendices A and B to part 75 of this chapter.

(3) You must use only unadjusted exhaust gas volumetric flow rates to determine the hourly CO_2 mass emissions rate from the affected EGU; you must not apply the bias adjustment factors described in Section 7.6.5 of appendix A to part 75 of this chapter to the exhaust gas flow rate data.

(4) You must select an appropriate reference method to setup (characterize) the flow monitor and to perform the on-going RATAs, in accordance with part 75 of this chapter. If you use a Type-S pitot tube or a pitot tube assembly for the flow RATAs, you must calibrate the pitot tube or pitot tube assembly; you may not use the 0.84 default Type-S pitot tube coefficient specified in Method 2.

(5) Calculate the hourly CO_2 mass emissions (kg) as described in paragraphs (b)(5)(i) through (iv) of this section. Perform this calculation only for ''valid operating hours'', as defined in § 60.5540(a)(1).

(i) Begin with the hourly CO_2 mass emission rate (tons/h), obtained either from Equation F–11 in Appendix F to part 75 of this chapter (if CO_2 concentration is measured on a wet basis), or by following the procedure in section 4.2 of appendix F to part 75 of this chapter (if CO_2 concentration is measured on a dry basis).

(ii) Next, multiply each hourly CO_2 mass emission rate by the EGU or stack operating time in hours (as defined in § 72.2 of this chapter), to convert it to tons of CO_2.

(iii) Finally, multiply the result from paragraph (b)(5)(ii) of this section by 909.1 to convert it from tons of CO_2 to kg. Round off to the nearest kg.

(iv) The hourly CO_2 tons/h values and EGU (or stack) operating times used to calculate CO_2 mass emissions are required to be recorded under § 75.57(e) of this chapter and must be reported electronically under § 75.64(a)(6) of this chapter. You must use these data to calculate the hourly CO_2 mass emissions.

(c) If your affected EGU exclusively combusts liquid fuel and/or gaseous fuel, as an alternative to complying with paragraph (b) of this section, you may determine the hourly CO_2 mass emissions according to paragraphs (c)(1) through (4) of this section. If you use non-uniform fuels as specified in § 60.5520(d)(2), you may determine CO_2 mass emissions during the compliance period according to paragraph (c)(5) of this section.

(1) If you are subject to an output-based standard and you do not install CEMS in accordance with paragraph (b) of this section, you must implement the applicable procedures in appendix D to part 75 of this chapter to determine hourly EGU heat input rates (MMBtu/h), based on hourly measurements of fuel flow rate and periodic determinations of the gross calorific value (GCV) of each fuel combusted.

(2) For each measured hourly heat input rate, use Equation G–4 in appendix G to part 75 of this chapter to calculate the hourly CO_2 mass emission rate (tons/h). You may determine site-specific carbon-based F-factors (F_c) using Equation F–7b in section 3.3.6 of appendix F to part 75 of this chapter, and you may use these F_c values in the emissions calculations instead of using the default F_c values in the Equation G–4 nomenclature.

(3) For each ''valid operating hour'' (as defined in § 60.5540(a)(1), multiply the hourly tons/h CO_2 mass emission rate from paragraph (c)(2) of this section by the EGU or stack operating time in hours (as defined in § 72.2 of this chapter), to convert it to tons of CO_2. Then, multiply the result by 909.1 to convert from tons of CO_2 to kg. Round off to the nearest two significant figures.

(4) The hourly CO_2 tons/h values and EGU (or stack) operating times used to calculate CO_2 mass emissions are required to be recorded under § 75.57(e) of this chapter and must be reported electronically under § 75.64(a)(6) of this chapter. You must use these data to calculate the hourly CO_2 mass emissions.

(5) If you operate a combustion turbine firing non-uniform fuels, as an alternative to following paragraphs (c)(1) through (4) of this section, you may determine CO_2 emissions during the compliance period using one of the following methods:

(i) Units firing fuel gas may determine the heat input during the compliance period following the procedure under § 60.107a(d) and convert this heat input to CO_2 emissions using Equation G–4 in appendix G to part 75 of this chapter.

(ii) You may use the procedure for determining CO_2 emissions during the compliance period based on the use of the Tier 3 methodology under § 98.33(a)(3) of this chapter.

(d) Consistent with § 60.5520, you must determine the basis of the emissions standard that applies to your affected source in accordance with either paragraph (d)(1) or (2) of this section, as applicable:

(1) If you operate a source subject to an emissions standard established on an output basis (*e.g.,* lb of CO_2 per gross or net MWh of energy output), you must install, calibrate, maintain, and operate a sufficient number of watt meters to continuously measure and record the hourly gross electric output or net electric output, as applicable, from the affected EGU(s). These measurements must be performed using 0.2 class electricity metering instrumentation and calibration procedures as specified under ANSI Standards No. C12.20 (incorporated by reference, see § 60.17). For a combined heat and power (CHP) EGU, as defined in § 60.5580, you must also install, calibrate, maintain, and operate meters to continuously (*i.e.,* hour-by-hour) determine and record the total useful thermal output. For process steam applications, you will need to install, calibrate, maintain, and operate meters to continuously determine and record the hourly steam flow rate, temperature, and pressure. Your plan shall ensure that you install, calibrate, maintain, and operate meters to record each component of the determination, hour-by-hour.

(2) If you operate a source subject to an emissions standard established on a heat-input basis (*e.g.,* lb CO_2/MMBtu) and your affected source uses non-uniform heating value fuels as delineated under § 60.5520(d), you must determine the total heat input for each fuel fired during the compliance period in accordance with one of the following procedures:

(i) Appendix D to part 75 of this chapter;

(ii) The procedures for monitoring heat input under § 60.107a(d);

(iii) If you monitor CO_2 emissions in accordance with the Tier 3 methodology under § 98.33(a)(3) of this chapter, you may convert your CO_2 emissions to heat input using the appropriate emission factor in Table C–1 of part 98 of this chapter. If your fuel is not listed in Table C–1, you must determine a fuel-specific carbon-based F-factor (F_c) in accordance with section 12.3.2 of EPA Method 19 of appendix A–7 to this part, and you must convert your CO_2 emissions to heat input using Equation G–4 in appendix G to part 75 of this chapter.

(e) Consistent with § 60.5520, if two or more affected EGUs serve a common electric generator, you must apportion the combined hourly gross or net energy output to the individual affected EGUs according to the fraction of the total steam load contributed by each EGU. Alternatively, if the EGUs are identical, you may apportion the combined hourly gross or net electrical load to the individual EGUs according to the fraction of the total heat input contributed by each EGU.

(f) In accordance with §§ 60.13(g) and 60.5520, if two or more affected EGUs that implement the continuous emission monitoring provisions in paragraph (b) of this section share a common exhaust gas stack and are subject to the same emissions standard in Table 1 or 2 of this subpart, you may monitor the hourly CO_2 mass emissions at the common stack in lieu of monitoring each EGU separately. If you choose this option, the hourly gross or net energy output (electric, thermal, and/or mechanical, as applicable) must be the sum of the hourly loads for the individual affected EGUs and you must express the operating time as ''stack operating hours'' (as defined in § 72.2 of this chapter). If you attain compliance with the applicable emissions standard in § 60.5520 at the common stack, each affected EGU sharing the stack is in compliance.

(g) In accordance with §§ 60.13(g) and 60.5520 if the exhaust gases from an affected EGU that implements the continuous emission monitoring provisions in paragraph (b) of this section are emitted to the atmosphere through multiple stacks (or if the exhaust gases are routed to a common stack through multiple ducts and you elect to monitor in the ducts), you must monitor the hourly CO_2 mass emissions and the ''stack operating time'' (as defined in § 72.2 of this chapter) at each stack or duct separately. In this case, you must determine compliance with the applicable emissions standard in Table 1 or 2 of this subpart by summing the CO_2 mass emissions measured at the individual stacks or ducts and dividing by the total gross or net energy output for the affected EGU.

§ 60.5540 How do I demonstrate compliance with my CO_2 emissions standard and determine excess emissions?

(a) In accordance with § 60.5520, if you are subject to an output-based emission standard or you burn non-uniform fuels as specified in § 60.5520(d)(2), you must demonstrate compliance with the applicable CO_2 emission standard in Table 1 or 2 of this subpart as required in this section. For the initial and each subsequent 12-operating-month rolling average compliance period, you must follow the procedures in paragraphs (a)(1) through (7) of this section to calculate the CO_2 mass emissions rate for your affected EGU(s) in units of the applicable emissions standard (*i.e.,* either kg/MWh or lb/MMBtu). You must use the hourly CO_2 mass emissions calculated under § 60.5535(b) or (c), as applicable, and either the generating load data from § 60.5535(d)(1) for output-based calculations or the heat input data from § 60.5535(d)(2) for heat-input-based calculations. Combustion turbines firing non-uniform fuels that contain CO_2 prior to combustion (*e.g.,* blast furnace gas or landfill gas) may sample the fuel stream to determine the quantity of CO_2 present in the fuel prior to combustion and exclude this portion of the CO_2 mass emissions from compliance determinations.

(1) Each compliance period shall include only ''valid operating hours'' in the compliance period, *i.e.,* operating hours for which:

(i) ''Valid data'' (as defined in § 60.5580) are obtained for all of the parameters used to determine the hourly CO_2 mass emissions (kg) and, if a heat input-based standard applies, all the parameters used to determine total heat input for the hour are also obtained; and

(ii) The corresponding hourly gross or net energy output value is also valid data (*Note:* For hours with no useful output, zero is considered to be a valid value).

(2) You must exclude operating hours in which:

(i) The substitute data provisions of part 75 of this chapter are applied for any of the parameters used to determine the hourly CO_2 mass emissions or, if a heat input-based standard applies, for any parameters used to determine the hourly heat input; or

(ii) An exceedance of the full-scale range of a continuous emission monitoring system occurs for any of the parameters used to determine the hourly CO_2 mass emissions or, if applicable, to determine the hourly heat input; or

(iii) The total gross or net energy output ($P_{gross/net}$) or, if applicable, the total heat input is unavailable.

(3) For each compliance period, at least 95 percent of the operating hours in the compliance period must be valid operating hours, as defined in paragraph (a)(1) of this section.

(4) You must calculate the total CO_2 mass emissions by summing the valid hourly CO_2 mass emissions values from § 60.5535 for all of the valid operating hours in the compliance period.

(5) *Sources subject to output based standards.* For each valid operating hour of the compliance period that was used in paragraph (a)(4) of this section to calculate the total CO_2 mass emissions, you must determine $P_{gross/net}$ (the corresponding hourly gross or net energy output in MWh) according to the

procedures in paragraphs (a)(3)(i) and (ii) of this section, as appropriate for the type of affected EGU(s). For an operating hour in which a valid CO_2 mass emissions value is determined according to paragraph (a)(1)(i) of this section, if there is no gross or net electrical output, but there is mechanical or useful thermal output, you must still determine the gross or net energy output for that hour. In addition, for an operating hour in which a valid CO_2 mass emissions value is determined according to paragraph (a)(1)(i) of this section, but there is no (*i.e.,* zero) gross electrical, mechanical, or useful thermal output, you must use that hour in the compliance determination. For hours or partial hours where the gross electric output is equal to or less than the auxiliary loads, net electric output shall be counted as zero for this calculation.

(i) Calculate $P_{gross/net}$ for your affected EGU using the following equation. All terms in the equation must be expressed in units of megawatt-hours (MWh). To convert each hourly gross or net energy output (consistent with § 60.5520) value reported under part 75 of this chapter to MWh, multiply by the corresponding EGU or stack operating time.

$$P_{gross/net} = \frac{(Pe)_{ST} + (Pe)_{CT} + (Pe)_{IE} - (Pe)_{FW} - (Pe)_{A}}{\text{TDF}} + [(Pt)_{PS} + (Pt)_{HR} + (Pt)_{IE}] \quad \text{(Eq. 2)}$$

Where:

$P_{gross/net}$ = In accordance with § 60.5520, gross or net energy output of your affected EGU for each valid operating hour (as defined in § 60.5540(a)(1)) in MWh.

$(Pe)_{ST}$ = Electric energy output plus mechanical energy output (if any) of steam turbines in MWh.

$(Pe)_{CT}$ = Electric energy output plus mechanical energy output (if any) of stationary combustion turbine(s) in MWh.

$(Pe)_{IE}$ = Electric energy output plus mechanical energy output (if any) of your affected EGU's integrated equipment that provides electricity or mechanical energy to the affected EGU or auxiliary equipment in MWh.

$(Pe)_{FW}$ = Electric energy used to power boiler feedwater pumps at steam generating units in MWh. Not applicable to stationary combustion turbines, IGCC EGUs, or EGUs complying with a net energy output based standard.

$(Pe)_{A}$ = Electric energy used for any auxiliary loads in MWh. Not applicable for determining P_{gross}.

$(Pt)_{PS}$ = Useful thermal output of steam (measured relative to SATP conditions, as applicable) that is used for applications that do not generate additional electricity, produce mechanical energy output, or enhance the performance of the affected EGU. This is calculated using the equation specified in paragraph (a)(5)(ii) of this section in MWh.

$(Pt)_{HR}$ = Non steam useful thermal output (measured relative to SATP conditions, as applicable) from heat recovery that is used for applications other than steam generation or performance enhancement of the affected EGU in MWh.

$(Pt)_{IE}$ = Useful thermal output (relative to SATP conditions, as applicable) from any integrated equipment is used for applications that do not generate additional steam, electricity, produce mechanical energy output, or enhance the performance of the affected EGU in MWh.

TDF = Electric Transmission and Distribution Factor of 0.95 for a combined heat and power affected EGU where at least on an annual basis 20.0 percent of the total gross or net energy output consists of electric or direct mechanical output and 20.0 percent of the total gross or net energy output consists of useful thermal output on a 12-operating-month rolling average basis, or 1.0 for all other affected EGUs.

(ii) If applicable to your affected EGU (for example, for combined heat and power), you must calculate $(Pt)_{PS}$ using the following equation:

$$(Pt)_{PS} = \frac{Q_m \times H}{CF} \quad \text{(Eq. 3)}$$

Where:

Q_m = Measured steam flow in kilograms (kg) (or pounds (lb)) for the operating hour.

H = Enthalpy of the steam at measured temperature and pressure (relative to SATP conditions or the energy in the condensate return line, as applicable) in Joules per kilogram (J/kg) (or Btu/lb).

CF = Conversion factor of 3.6×10^9 J/MWh or 3.413×10^6 Btu/MWh.

(6) *Calculation of annual basis for standard.* Sources complying with energy output-based standards must calculate the basis (*i.e.,* denominator) of their actual annual emission rate in accordance with paragraph (a)(6)(i) of this section. Sources complying with heat input based standards must calculate the basis of their actual annual emission rate in accordance with paragraph (a)(6)(ii) of this section.

(i) In accordance with § 60.5520 if you are subject to an output-based standard, you must calculate the total gross or net energy output for the affected EGU's compliance period by summing the hourly gross or net energy output values for the affected EGU that you determined under paragraph (a)(5) of this section for all of the valid operating hours in the applicable compliance period.

(ii) If you are subject to a heat input-based standard, you must calculate the total heat input for each fuel fired during the compliance period. The calculation of total heat input for each individual fuel must include all valid operating hours and must also be consistent with any fuel-specific procedures specified within your selected monitoring option under § 60.5535(d)(2).

(7) If you are subject to an output-based standard, you must calculate the CO_2 mass emissions rate for the affected EGU(s) (kg/MWh) by dividing the total CO_2 mass emissions value calculated according to the procedures in paragraph (a)(4) of this section by the total gross or net energy output value calculated according to the procedures in paragraph (a)(6)(i) of this section. Round off the result to two significant figures if the calculated value is less than 1,000; round the result to three significant figures if the calculated value is greater than 1,000. If you are subject to a heat input-based standard, you must calculate the CO_2 mass emissions rate for the affected EGU(s) (lb/MMBtu) by dividing the total CO_2 mass emissions value calculated according to the procedures in paragraph (a)(4) of this section by the total heat input calculated according to the procedures in paragraph (a)(6)(ii) of this section. Round off the result to two significant figures.

(b) In accordance with § 60.5520, to demonstrate compliance with the applicable CO_2 emission standard, for the initial and each subsequent 12-operating-month compliance period, the CO_2 mass emissions rate for your affected EGU must be determined according to the procedures specified in paragraph (a)(1) through (7) of this section and must be less than or equal to the applicable CO_2 emissions standard in Table 1 or 2 of this part, or the emissions standard calculated in accordance with § 60.5525(a)(2).

Notification, Reports, and Records

§ 60.5550 What notifications must I submit and when?

(a) You must prepare and submit the notifications specified in §§ 60.7(a)(1) and (3) and 60.19, as applicable to your affected EGU(s) (see Table 3 of this subpart).

(b) You must prepare and submit notifications specified in § 75.61 of this chapter, as applicable, to your affected EGUs.

§ 60.5555 What reports must I submit and when?

(a) You must prepare and submit reports according to paragraphs (a) through (d) of this section, as applicable.

(1) For affected EGUs that are required by § 60.5525 to conduct initial and on-going compliance determinations on a 12-operating-month rolling average basis, you must submit electronic quarterly reports as follows. After you have accumulated the first 12-operating months for the affected EGU, you must submit a report for the calendar quarter that includes the twelfth operating month no later than 30 days after the end of that quarter. Thereafter, you must submit a report for each subsequent calendar quarter, no later than 30 days after the end of the quarter.

(2) In each quarterly report you must include the following information, as applicable:

(i) Each rolling average CO_2 mass emissions rate for which the last (twelfth) operating month in a 12-operating-month compliance period falls within the calendar quarter. You must calculate each average CO_2 mass emissions rate for the compliance period according to the procedures in § 60.5540. You must report the dates (month and year) of the first and twelfth operating months in each compliance period for which you performed a CO_2 mass emissions rate calculation. If there are no compliance periods that end in the quarter, you must include a statement to that effect;

(ii) If one or more compliance periods end in the quarter, you must identify each operating month in the calendar quarter where your EGU violated the applicable CO_2 emission standard;

(iii) If one or more compliance periods end in the quarter and there are no violations for the affected EGU, you must include a statement indicating this in the report;

(iv) The percentage of valid operating hours in each 12-operating-month compliance period described in paragraph (a)(1)(i) of this section (*i.e.,* the total number of valid operating hours (as defined in § 60.5540(a)(1)) in that period divided by the total number of operating hours in that period, multiplied by 100 percent);

(v) Consistent with § 60.5520, the CO_2 emissions standard (as identified in Table 1 or 2 of this part) with which your affected EGU must comply; and

(vi) Consistent with § 60.5520, an indication whether or not the hourly gross or net energy output ($P_{gross/net}$) values used in the compliance determinations are based solely upon gross electrical load.

(3) In the final quarterly report of each calendar year, you must include the following:

(i) Consistent with § 60.5520, gross energy output or net energy output sold to an electric grid, as applicable to the units of your emission standard, over the four quarters of the calendar year; and

(ii) The potential electric output of the EGU.

(b) You must submit all electronic reports required under paragraph (a) of this section using the Emissions Collection and Monitoring Plan System (ECMPS) Client Tool provided by the Clean Air Markets Division in the Office of Atmospheric Programs of EPA.

(c)(1) For affected EGUs under this subpart that are also subject to the Acid Rain Program, you must meet all applicable reporting requirements and submit reports as required under subpart G of part 75 of this chapter.

(2) For affected EGUs under this subpart that are not in the Acid Rain Program, you must also meet the reporting requirements and submit reports as required under subpart G of part 75 of this chapter, to the extent that those requirements and reports provide applicable data for the compliance demonstrations required under this subpart.

(3)(i) For all newly-constructed affected EGUs under this subpart that are also subject to the Acid Rain Program, you must begin submitting the quarterly electronic emissions reports described in paragraph (c)(1) of this section in accordance with § 75.64(a) of this chapter, *i.e.,* beginning with data recorded on and after the earlier of:

(A) The date of provisional certification, as defined in § 75.20(a)(3) of this chapter; or

(B) 180 days after the date on which the EGU commences commercial operation (as defined in § 72.2 of this chapter).

(ii) For newly-constructed affected EGUs under this subpart that are not subject to the Acid Rain Program, you must begin submitting the quarterly electronic reports described in paragraph (c)(2) of this section, beginning with data recorded on and after:

(A) The date on which reporting is required to begin under § 75.64(a) of this chapter, if that date occurs on or after October 23, 2015; or

(B) October 23, 2015, if the date on which reporting would ordinarily be required to begin under § 75.64(a) of this chapter has passed prior to October 23, 2015.

(iii) For reconstructed or modified units, reporting of emissions data shall begin at the date on which the EGU becomes an affected unit under this subpart, provided that the ECMPS Client Tool is able to receive and process net energy output data on that date. Otherwise, emissions data reporting shall be on a gross energy output basis until the date that the Client Tool is first able to receive and process net energy output data.

(4) If any required monitoring system has not been provisionally certified by the applicable date on which emissions data reporting is required to begin under paragraph (c)(3) of this section, the maximum (or in some cases, minimum) potential value for the parameter measured by the monitoring system shall be reported until the required certification testing is successfully completed, in accordance with § 75.4(j) of this chapter, § 75.37(b) of this chapter, or section 2.4 of appendix D to part 75 of this chapter (as applicable). Operating hours in which CO_2 mass emission rates are calculated using maximum potential values are not ''valid operating hours'' (as defined in § 60.5540(a)(1)), and shall not be used in the compliance determinations under § 60.5540.

(d) For affected EGUs subject to the Acid Rain Program, the reports required under paragraphs (a) and (c)(1) of this section shall be submitted by:

(1) The person appointed as the Designated Representative (DR) under § 72.20 of this chapter; or

(2) The person appointed as the Alternate Designated Representative (ADR) under § 72.22 of this chapter; or

(3) A person (or persons) authorized by the DR or ADR under § 72.26 of this chapter to make the required submissions.

(e) For affected EGUs that are not subject to the Acid Rain Program, the owner or operator shall appoint a DR and (optionally) an ADR to submit the reports required under paragraphs (a) and (c)(2) of this section. The DR and ADR must register with the Clean Air Markets Division (CAMD) Business System. The DR may delegate the authority to make the required submissions to one or more persons.

(f) If your affected EGU captures CO_2 to meet the applicable emission limit, you must report in accordance with the requirements of 40 CFR part 98, subpart PP and either:

(1) Report in accordance with the requirements of 40 CFR part 98, subpart RR, if injection occurs on-site, or

(2) Transfer the captured CO_2 to an EGU or facility that reports in accordance with the requirements of 40 CFR part 98, subpart RR, if injection occurs off-site.

(3) Transfer the captured CO_2 to a facility that has received an innovative technology waiver from EPA pursuant to paragraph (g) of this section.

(g) Any person may request the Administrator to issue a waiver of the requirement that captured CO_2 from an affected EGU be transferred to a facility reporting under 40 CFR part 98, subpart RR. To receive a waiver, the applicant must demonstrate to the Administrator that its technology will store captured CO_2 as effectively as geologic sequestration, and that the proposed technology will not cause or contribute to an unreasonable risk to public health, welfare, or safety. In making this determination, the Administrator shall consider (among other factors) operating history of the technology, whether the technology will increase emissions or other releases of any pollutant other than CO_2, and permanence of the CO_2 storage. The Administrator may test the system itself, or require the applicant to perform any tests considered by the Administrator to be necessary to show the technology's effectiveness, safety, and ability to store captured CO_2 without release. The Administrator may grant conditional approval of a technology, with the approval conditioned on monitoring and reporting of operations. The Administrator may also withdraw approval of the waiver on evidence of releases of CO_2 or other pollutants. The Administrator will provide notice to the public of any application under this provision and provide public notice of any proposed action on a petition before the Administrator takes final action.

§ 60.5560 What records must I maintain?

(a) You must maintain records of the information you used to demonstrate compliance with this subpart as specified in § 60.7(b) and (f).

(b)(1) For affected EGUs subject to the Acid Rain Program, you must follow the applicable recordkeeping requirements and maintain records as required under subpart F of part 75 of this chapter.

(2) For affected EGUs that are not subject to the Acid Rain Program, you must also follow the recordkeeping requirements and maintain records as required under subpart F of part 75 of this chapter, to the extent that those records provide applicable data for the compliance determinations required under this subpart. Regardless of the prior sentence, at a minimum, the following records must be kept, as applicable to the types of continuous monitoring systems used to demonstrate compliance under this subpart:

(i) Monitoring plan records under § 75.53(g) and (h) of this chapter;

(ii) Operating parameter records under § 75.57(b)(1) through (4) of this chapter;

(iii) The records under § 75.57(c)(2) of this chapter, for stack gas volumetric flow rate;

(iv) The records under § 75.57(c)(3) of this chapter for continuous moisture monitoring systems;

(v) The records under § 75.57(e)(1) of this chapter, except for paragraph (e)(1)(x), for CO_2 concentration monitoring systems or O_2 monitors used to calculate CO_2 concentration;

(vi) The records under § 75.58(c)(1) of this chapter, specifically paragraphs (c)(1)(i), (ii), and (viii) through (xiv), for oil flow meters;

(vii) The records under § 75.58(c)(4) of this chapter, specifically paragraphs (c)(4)(i), (ii), (iv), (v), and (vii) through (xi), for gas flow meters;

(viii) The quality-assurance records under § 75.59(a) of this chapter, specifically paragraphs (a)(1) through (12) and (15), for CEMS;

(ix) The quality-assurance records under § 75.59(a) of this chapter, specifically paragraphs (b)(1) through (4), for fuel flow meters; and

(x) Records of data acquisition and handling system (DAHS) verification under § 75.59(e) of this chapter.

(c) You must keep records of the calculations you performed to determine the hourly and total CO_2 mass emissions (tons) for:

(1) Each operating month (for all affected EGUs); and

(2) Each compliance period, including, each 12-operating-month compliance period.

(d) Consistent with § 60.5520, you must keep records of the applicable data recorded and calculations performed that you used to determine your affected EGU's gross or net energy output for each operating month.

(e) You must keep records of the calculations you performed to determine the percentage of valid CO_2 mass emission rates in each compliance period.

(f) You must keep records of the calculations you performed to assess compliance with each applicable CO_2 mass emissions standard in Table 1 or 2 of this subpart.

(g) You must keep records of the calculations you performed to determine any site-specific carbon-based F-factors you used in the emissions calculations (if applicable).

§ 60.5565 In what form and how long must I keep my records?

(a) Your records must be in a form suitable and readily available for expeditious review.

(b) You must maintain each record for 3 years after the date of conclusion of each compliance period.

(c) You must maintain each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to § 60.7. Records that are accessible from a central location by a computer or other means that instantly provide access at the site meet this requirement. You may maintain the records off site for the remaining year(s) as required by this subpart.

Other Requirements and Information

§ 60.5570 What parts of the general provisions apply to my affected EGU?

Notwithstanding any other provision of this chapter, certain parts of the general provisions in §§ 60.1 through 60.19, listed in Table 3 to this subpart, do not apply to your affected EGU.

§ 60.5575 Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by the EPA, or a delegated authority such as your state, local, or tribal agency. If the Administrator has delegated authority to your state, local, or tribal agency, then that agency (as well as the EPA) has the authority to implement and enforce this subpart. You should contact your EPA Regional Office to find out if this subpart is delegated to your state, local, or tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a state, local, or tribal agency, the Administrator retains the authorities listed in paragraphs (b)(1) through (5) of this section and does not transfer them to the state, local, or tribal agency. In addition, the EPA retains oversight of this subpart and can take enforcement actions, as appropriate.

(1) Approval of alternatives to the emission standards.

(2) Approval of major alternatives to test methods.

(3) Approval of major alternatives to monitoring.

(4) Approval of major alternatives to recordkeeping and reporting.

(5) Performance test and data reduction waivers under § 60.8(b).

§ 60.5580 What definitions apply to this subpart?

As used in this subpart, all terms not defined herein will have the meaning given them in the Clean Air Act and in subpart A (general provisions of this part).

Annual capacity factor means the ratio between the actual heat input to an EGU during a calendar year and the potential heat input to the EGU had it been operated for 8,760 hours during a calendar year at the base load rating.

Base load rating means the maximum amount of heat input (fuel) that an EGU can combust on a steady state basis, as determined by the physical design and characteristics of the EGU at ISO conditions. For a stationary combustion turbine, *base load rating* includes the heat input from duct burners.

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by ASTM International in ASTM D388–99 (Reapproved 2004) ε^1 (incorporated by reference, see § 60.17), coal refuse, and petroleum coke. Synthetic fuels derived from coal for the purpose of creating useful heat, including, but not limited to, solvent-refined coal, gasified coal (not meeting the definition of natural gas), coal-oil mixtures, and coal-water mixtures are included in this definition for the purposes of this subpart.

Combined cycle unit means an electric generating unit that uses a stationary combustion turbine from which the heat from the turbine exhaust gases is recovered by a heat recovery steam generating unit (HRSG) to generate additional electricity.

Combined heat and power unit or *CHP unit, (*also known as ''cogeneration'') means an electric generating unit that that use a steam generating unit or stationary combustion turbine to simultaneously produce both electric (or mechanical) and useful thermal output from the same primary energy source.

Design efficiency means the rated overall net efficiency (*e.g.,* electric plus useful thermal output) on a lower heating value basis at the base load rating, at ISO conditions, and at the maximum useful thermal output (*e.g.,* CHP unit with condensing steam turbines would determine the design efficiency at the maximum level of extraction and/or bypass). Design efficiency shall be determined using one of the following methods: ASME PTC 22 Gas Turbines (incorporated by reference, see § 60.17), ASME PTC 46 Overall Plant Performance (incorporated by reference, see § 60.17) or ISO 2314 Gas turbines—acceptance tests (incorporated by reference, see § 60.17).

Distillate oil means fuel oils that comply with the specifications for fuel oil numbers 1 and 2, as defined by ASTM International in ASTM D396–98 (incorporated by reference, see § 60.17); diesel fuel oil numbers 1 and 2, as defined by ASTM International in ASTM D975–08a (incorporated by reference, see § 60.17); kerosene, as defined by ASTM International in ASTM D3699 (incorporated by reference, see § 60.17); biodiesel as defined by ASTM International in ASTM D6751 (incorporated by reference, see § 60.17); or biodiesel blends as defined by ASTM International in ASTM D7467 (incorporated by reference, see § 60.17).

Electric Generating units or EGU means any steam generating unit, IGCC unit, or stationary combustion turbine that is subject to this rule (*i.e.,* meets the applicability criteria)

Fossil fuel means natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such material for the purpose of creating useful heat.

Gaseous fuel means any fuel that is present as a gas at ISO conditions and includes, but is not limited to, natural gas, refinery fuel gas, process gas, coke-oven gas, synthetic gas, and gasified coal.

Gross energy output means:

(1) For stationary combustion turbines and IGCC, the gross electric or direct mechanical output from both the EGU (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)) plus 100 percent of the useful thermal output.

(2) For steam generating units, the gross electric or mechanical output from the affected EGU(s) (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)) minus any electricity used to power the feedwater pumps plus 100 percent of the useful thermal output;

(3) For combined heat and power facilities where at least 20.0 percent of the total gross energy output consists of electric or direct mechanical output and 20.0 percent of the total gross energy output consists of useful thermal output on a 12-operating-month rolling average basis, the gross electric or mechanical output from the affected EGU (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)) minus any electricity used to power the feedwater pumps (the electric auxiliary load of boiler feedwater pumps is not applicable to IGCC facilities), that difference divided by 0.95, plus 100 percent of the useful thermal output.

Heat recovery steam generating unit (HRSG) means an EGU in which hot exhaust gases from the combustion turbine engine are routed in order to extract heat from the gases and generate useful output. Heat recovery steam generating units can be used with or without duct burners.

Integrated gasification combined cycle facility or *IGCC* means a combined cycle facility that is designed to burn fuels containing 50 percent (by heat input) or more solid-derived fuel not meeting the definition of natural gas, plus any integrated equipment that provides electricity or useful thermal output to the affected EGU or auxiliary equipment. The Administrator may waive the 50 percent solid-derived fuel requirement during periods of the gasification system construction, startup and commissioning, shutdown, or repair. No solid fuel is directly burned in the EGU during operation.

ISO conditions means 288 Kelvin (15°C), 60 percent relative humidity and 101.3 kilopascals pressure.

Liquid fuel means any fuel that is present as a liquid at ISO conditions and includes, but is not limited to, distillate oil and residual oil.

Mechanical output means the useful mechanical energy that is not used to operate the affected EGU(s), generate electricity and/or thermal energy, or to enhance the performance of the affected EGU. Mechanical energy measured in horsepower hour should be converted into MWh by multiplying it by 745.7 then dividing by 1,000,000.

Natural gas means a fluid mixture of hydrocarbons (*e.g.,* methane, ethane, or propane), composed of at least 70 percent methane by volume or that has a gross calorific value between 35 and 41 megajoules (MJ) per dry standard cubic meter (950 and 1,100 Btu per dry standard cubic foot), that maintains a gaseous state under ISO conditions. Finally, natural gas does not include the following gaseous fuels: Landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable CO_2 content or heating value.

Net-electric sales means:

(1) The gross electric sales to the utility power distribution system minus purchased power; or

(2) For combined heat and power facilities where at least 20.0 percent of the total gross energy output consists of electric or direct mechanical output and at least 20.0 percent of the total gross energy output consists of useful thermal output on an annual basis, the gross electric sales to the utility power

distribution system minus purchased power of the thermal host facility or facilities.

(3) Electricity supplied to other facilities that produce electricity to offset auxiliary loads are included when calculating net-electric sales.

(4) Electric sales that that result from a system emergency are not included when calculating net-electric sales.

Net-electric output means the amount of gross generation the generator(s) produces (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)), as measured at the generator terminals, less the electricity used to operate the plant (*i.e.,* auxiliary loads); such uses include fuel handling equipment, pumps, fans, pollution control equipment, other electricity needs, and transformer losses as measured at the transmission side of the step up transformer (*e.g.,* the point of sale).

Net energy output means:

(1) The net electric or mechanical output from the affected EGU plus 100 percent of the useful thermal output; or

(2) For combined heat and power facilities where at least 20.0 percent of the total gross or net energy output consists of electric or direct mechanical output and at least 20.0 percent of the total gross or net energy output consists of useful thermal output on a 12-operating-month rolling average basis, the net electric or mechanical output from the affected EGU divided by 0.95, plus 100 percent of the useful thermal output.

Operating month means a calendar month during which any fuel is combusted in the affected EGU at any time.

Petroleum means crude oil or a fuel derived from crude oil, including, but not limited to, distillate and residual oil.

Potential electric output means 33 percent or the base load rating design efficiency at the maximum electric production rate (*e.g.,* CHP units with condensing steam turbines will operate at maximum electric production), whichever is greater, multiplied by the base load rating (expressed in MMBtu/h) of the EGU, multiplied by 10^6 Btu/MMBtu, divided by 3,413 Btu/KWh, divided by 1,000 kWh/MWh, and multiplied by 8,760 h/yr (*e.g.,* a 35 percent efficient affected EGU with a 100 MW (341 MMBtu/h) fossil fuel heat input capacity would have a 306,000 MWh 12-month potential electric output capacity).

Standard ambient temperature and pressure (SATP) conditions means 298.15 Kelvin (25 °C, 77 °F) and 100.0 kilopascals (14.504 psi, 0.987 atm) pressure. The enthalpy of water at SATP conditions is 50 Btu/lb.

Solid fuel means any fuel that has a definite shape and volume, has no tendency to flow or disperse under moderate stress, and is not liquid or gaseous at ISO conditions. This includes, but is not limited to, coal, biomass, and pulverized solid fuels.

Stationary combustion turbine means all equipment including, but not limited to, the turbine engine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), heat recovery system, fuel compressor, heater, and/or pump, post-combustion emission control technology, and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any combined cycle combustion turbine, and any combined heat and power combustion turbine based system plus any integrated equipment that provides electricity or useful thermal output to the combustion turbine engine, heat recovery system or auxiliary equipment. Stationary means that the combustion turbine is not self-propelled or intended to be propelled while performing its function. It may, however, be mounted on a vehicle for portability. A stationary combustion turbine that burns any solid fuel directly is considered a steam generating unit.

Steam generating unit means any furnace, boiler, or other device used for combusting fuel and producing steam (nuclear steam generators are not included) plus any integrated equipment that provides electricity or useful thermal output to the affected EGU(s) or auxiliary equipment.

System emergency means any abnormal system condition that the Regional Transmission Organizations (RTO), Independent System Operators (ISO) or control area Administrator determines requires immediate automatic or manual action to prevent or limit loss of transmission facilities or generators that could adversely affect the reliability of the power system and therefore call for maximum generation resources to operate in the affected area, or for the specific affected EGU to operate to avert loss of load.

Useful thermal output means the thermal energy made available for use in any heating application (*e.g.,* steam delivered to an industrial process for a heating application, including thermal cooling applications) that is not used for electric generation, mechanical output at the affected EGU, to directly enhance the performance of the affected EGU (*e.g.,* economizer output is not useful thermal output, but thermal energy used to reduce fuel moisture is considered useful thermal output), or to supply energy to a pollution control device at the affected EGU. Useful thermal output for affected EGU(s) with no condensate return (or other thermal energy input to the affected EGU(s)) or where measuring the energy in the condensate (or other thermal energy input to the affected EGU(s)) would not meaningfully impact the emission rate calculation is measured against the energy in the thermal output at SATP conditions. Affected EGU(s) with meaningful energy in the condensate return (or other thermal energy input to the affected EGU) must measure the energy in the condensate and subtract that energy relative to SATP conditions from the measured thermal output.

Valid data means quality-assured data generated by continuous monitoring systems that are installed, operated, and maintained according to part 75 of this chapter. For CEMS, the initial certification requirements in § 75.20 of this chapter and appendix A to part 75 of this chapter must be met before quality-assured data are reported under this subpart; for on-going quality assurance, the daily, quarterly, and semiannual/annual test requirements in sections 2.1, 2.2, and 2.3 of appendix B to part 75 of this chapter must be met and the data validation criteria in sections 2.1.5, 2.2.3, and 2.3.2 of appendix B to part 75 of this chapter apply. For fuel flow meters, the initial certification requirements in section 2.1.5 of appendix D to part 75 of this chapter must be met before quality-assured data are reported under this subpart (except for qualifying commercial billing meters under section 2.1.4.2 of appendix D to part 75), and for on-going quality assurance, the provisions in section 2.1.6 of appendix D to part 75 apply (except for qualifying commercial billing meters).

Violation means a specified averaging period over which the CO_2 emissions rate is higher than the applicable emissions standard located in Table 1 or 2 of this subpart.

TABLE 1 OF SUBPART TTTT OF PART 60—CO_2 EMISSION STANDARDS FOR AFFECTED STEAM GENERATING UNITS AND INTEGRATED GASIFICATION COMBINED CYCLE FACILITIES THAT COMMENCED CONSTRUCTION AFTER JANUARY 8, 2014 AND RECONSTRUCTION OR MODIFICATION AFTER JUNE 18, 2014

[Note: Numerical values of 1,000 or greater have a minimum of 3 significant figures and numerical values of less than 1,000 have a minimum of 2 significant figures]

Affected EGU	CO_2 Emission standard
Newly constructed steam generating unit or integrated gasification combined cycle (IGCC).	640 kg CO_2/MWh of gross energy output (1,400 lb CO_2/MWh).
Reconstructed steam generating unit or IGCC that has base load rating of 2,100 GJ/h (2,000 MMBtu/h) or less.	910 kg of CO_2 per MWh of gross energy output (2,000 lb CO_2/MWh).
Reconstructed steam generating unit or IGCC that has a base load rating greater than 2,100 GJ/h (2,000 MMBtu/h).	820 kg of CO_2 per MWh of gross energy output (1,800 lb CO_2/MWh).
Modified steam generating unit or IGCC	A unit-specific emission limit determined by the unit's best historical annual CO_2 emission rate (from 2002 to the date of the modification); the emission limit will be no lower than: 1. 1,800 lb CO_2/MWh-gross for units with a base load rating greater than 2,000 MMBtu/h; or 2. 2,000 lb CO_2/MWh-gross for units with a base load rating of 2,000 MMBtu/h or less.

TABLE 2 OF SUBPART TTTT OF PART 60—CO_2 EMISSION STANDARDS FOR AFFECTED STATIONARY COMBUSTION TURBINES THAT COMMENCED CONSTRUCTION AFTER JANUARY 8, 2014 AND RECONSTRUCTION AFTER JUNE 18, 2014 (NET ENERGY OUTPUT-BASED STANDARDS APPLICABLE AS APPROVED BY THE ADMINISTRATOR)

[Note: Numerical values of 1,000 or greater have a minimum of 3 significant figures and numerical values of less than 1,000 have a minimum of 2 significant figures]

Affected EGU	CO_2 Emission standard
Newly constructed or reconstructed stationary combustion turbine that supplies more than its design efficiency or 50 percent, whichever is less, times its potential electric output as net-electric sales on both a 12-operating month and a 3-year rolling average basis and combusts more than 90% natural gas on a heat input basis on a 12-operating-month rolling average basis.	450 kg of CO_2 per MWh of gross energy output (1,000 lb CO_2/MWh); or 470 kilograms (kg) of CO_2 per megawatt-hour (MWh) of net energy output (1,030 lb/MWh).
Newly constructed or reconstructed stationary combustion turbine that supplies its design efficiency or 50 percent, whichever is less, times its potential electric output or less as net-electric sales on either a 12-operating month or a 3-year rolling average basis and combusts more than 90% natural gas on a heat input basis on a 12-operating-month rolling average basis.	50 kg CO_2 per gigajoule (GJ) of heat input (120 lb CO_2/MMBtu).
Newly constructed and reconstructed stationary combustion turbine that combusts 90% or less natural gas on a heat input basis on a 12-operating-month rolling average basis.	50 kg CO_2/GJ of heat input (120 lb/MMBtu) to 69 kg CO_2/GJ of heat input (160 lb/MMBtu) as determined by the procedures in § 60.5525.

TABLE 3 TO SUBPART TTTT OF PART 60—APPLICABILITY OF SUBPART A OF PART 60 (GENERAL PROVISIONS) TO SUBPART TTTT

General provisions citation	Subject of citation	Applies to subpart TTTT	Explanation
§ 60.1	Applicability	Yes.	
§ 60.2	Definitions	Yes	Additional terms defined in § 60.5580.
§ 60.3	Units and Abbreviations	Yes.	
§ 60.4	Address	Yes	Does not apply to information reported electronically through ECMPS. Duplicate submittals are not required.
§ 60.5	Determination of construction or modification	Yes.	
§ 60.6	Review of plans	Yes.	
§ 60.7	Notification and Recordkeeping	Yes	Only the requirements to submit the notifications in § 60.7(a)(1) and (3) and to keep records of malfunctions in § 60.7(b), if applicable.
§ 60.8	Performance tests	No.	
§ 60.9	Availability of Information	Yes.	
§ 60.10	State authority	Yes.	
§ 60.11	Compliance with standards and maintenance requirements.	No.	
§ 60.12	Circumvention	Yes.	
§ 60.13	Monitoring requirements	No	All monitoring is done according to part 75.

TABLE 3 TO SUBPART TTTT OF PART 60—APPLICABILITY OF SUBPART A OF PART 60 (GENERAL PROVISIONS) TO SUBPART TTTT—Continued

General provisions citation	Subject of citation	Applies to subpart TTTT	Explanation
§ 60.14	Modification	Yes (steam generating units and IGCC facilities). No (stationary combustion turbines.	
§ 60.15	Reconstruction	Yes.	
§ 60.16	Priority list	No.	
§ 60.17	Incorporations by reference	Yes.	
§ 60.18	General control device requirements	No.	
§ 60.19	General notification and reporting requirements	Yes	Does not apply to notifications under § 75.61 or to information reported through ECMPS.

PART 70—STATE OPERATING PERMIT PROGRAMS

■ 4. The authority citation for part 70 continues to read as follows:

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

■ 5. In § 70.2, the definition of ''Regulated pollutant (for presumptive fee calculation)'' is amended by:
■ a. Revising the introductory text;
■ b. Removing ''or'' from the end of paragraph (2);
■ c. Removing the period at the end of paragraph (3) and adding ''; or'' in its place; and
■ d. Adding paragraph (4).

The revision and additions read as follows:

§ 70.2 Definitions.

* * * * *

Regulated pollutant (for presumptive fee calculation), which is used only for purposes of § 70.9(b)(2), means any regulated air pollutant except the following:

* * * * *

(4) Greenhouse gases.

* * * * *

■ 6. Section 70.9 is amended by revising paragraph (b)(2)(i), and adding paragraph (b)(2)(v) to read as follows:

§ 70.9 Fee determination and certification.

* * * * *

(b) * * *

(2)(i) The Administrator will presume that the fee schedule meets the requirements of paragraph (b)(1) of this section if it would result in the collection and retention of an amount not less than $25 per year [as adjusted pursuant to the criteria set forth in paragraph (b)(2)(iv) of this section] times the total tons of the actual emissions of each regulated pollutant (for presumptive fee calculation) emitted from part 70 sources and any GHG cost adjustment required under paragraph (b)(2)(v) of this section.

* * * * *

(v) *GHG cost adjustment.* The amount calculated in paragraph (b)(2)(i) of this section shall be increased by the GHG cost adjustment determined as follows: For each activity identified in the following table, multiply the number of activities performed by the permitting authority by the burden hours per activity, and then calculate a total number of burden hours for all activities. Next, multiply the burden hours by the average cost of staff time, including wages, employee benefits and overhead.

Activity	Burden hours per activity
GHG completeness determination (for initial permit or updated application)	43
GHG evaluation for a permit modification or related permit action	7
GHG evaluation at permit renewal	10

* * * * *

PART 71—FEDERAL OPERATING PERMIT PROGRAMS

■ 7. The authority citation for part 71 continues to read as follows:

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

■ 8. In § 71.2, the definition of ''Regulated pollutant (for fee calculation)'' is amended by:
■ a. Removing ''or'' from the end of paragraph (2);
■ b. Removing the period at the end of paragraph (3) and adding ''; or'' in its place; and
■ b. Adding paragraph (4).

The revisions and additions read as follows:

§ 71.2 Definitions.

* * * * *

Regulated pollutant (for fee calculation), which is used only for purposes of § 71.9(c), means any ''*regulated air pollutant''* except the following:

* * * * *

(4) Greenhouse gases.

* * * * *

■ 9. Section 71.9 is amended by:
■ a. Revising paragraphs (c)(1), (c)(2)(i), (c)(3), and (c)(4); and
■ b. Adding paragraph (c)(8).

The revisions and addition read as follows:

§ 71.9 Permit fees.

* * * * *

(c) * * *

(1) For part 71 programs that are administered by EPA, each part 71 source shall pay an annual fee which is the sum of:

(i) $32 per ton (as adjusted pursuant to the criteria set forth in paragraph (n)(1) of this section) times the total tons of the actual emissions of each regulated pollutant (for fee calculation) emitted from the source, including fugitive emissions; and

(ii) Any GHG fee adjustment required under paragraph (c)(8) of this section.

(2) * * *

(i) Where the EPA has not suspended its part 71 fee collection pursuant to paragraph (c)(2)(ii) of this section, the annual fee for each part 71 source shall be the sum of:

(A) $24 per ton (as adjusted pursuant to the criteria set forth in paragraph (n)(1) of this section) times the total tons of the actual emissions of each regulated pollutant (for fee calculation) emitted from the source, including fugitive emissions; and

(B) Any GHG fee adjustment required under paragraph (c)(8) of this section.

* * * * *

(3) For part 71 programs that are administered by EPA with contractor assistance, the per ton fee shall vary depending on the extent of contractor involvement and the cost to EPA of contractor assistance. The EPA shall establish a per ton fee that is based on the contractor costs for the specific part 71 program that is being administered, using the following formula:

Cost per ton = $(E \times 32) + [(1 - E) \times \$C]$

Where E represents EPA's proportion of total effort (expressed as a percentage of total effort) needed to administer the part 71 program, $1 - E$ represents the contractor's effort, and C represents the contractor assistance cost on a per ton basis. C shall be computed by using the following formula:

$C = [B + T + N]$ divided by 12,300,000

Where B represents the base cost (contractor costs), where T represents travel costs, and where N represents nonpersonnel data management and tracking costs. In addition, each part 71 source shall pay a GHG fee adjustment for each activity as required under paragraph (c)(8) of this section.

(4) For programs that are delegated in part, the fee shall be computed using the following formula:

Cost per ton = $(E \times 32) + (D \times 24) + [(1 - E - D) \times \$C]$

Where E and D represent, respectively, the EPA and delegate agency proportions of total effort (expressed as a percentage of total effort) needed to administer the part 71 program, $1 - E - D$ represents the contractor's effort, and C represents the contractor assistance cost on a per ton basis. C shall be computed using the formula for contractor assistance cost found in paragraph (c)(3) of this section and shall be zero if contractor assistance is not utilized. In addition, each part 71 source shall pay a GHG fee adjustment for each activity as required under paragraph (c)(8) of this section.

* * * * *

(8) *GHG fee adjustment.* The annual fee shall be increased by a GHG fee adjustment for any source that has initiated an activity listed in the following table since the fee was last paid. The GHG fee adjustment shall be equal to the set fee provided in the table for each activity that has been initiated since the fee was last paid:

Activity	Set fee
GHG completeness determination (for initial permit or updated application)	$2,236
GHG evaluation for a permit modification or related permit action	364
GHG evaluation at permit renewal	520

* * * * *

PART 98—MANDATORY GREENHOUSE GAS REPORTING

■ 10. The authority citation for part 98 is revised to read as follows:

Authority: 42 U.S.C. 7401–7671q.

■ 11. Section 98.426 is amended by adding paragraph (h) to read as follows:

§ 98.426 Data reporting requirements.

* * * * *

(h) If you capture a CO_2 stream from an electricity generating unit that is subject to subpart D of this part and transfer CO_2 to any facilities that are subject to subpart RR of this part, you must:

(1) Report the facility identification number associated with the annual GHG report for the subpart D facility;

(2) Report each facility identification number associated with the annual GHG reports for each subpart RR facility to which CO_2 is transferred; and

(3) Report the annual quantity of CO_2 in metric tons that is transferred to each subpart RR facility.

■ 12. Section 98.427 is amended by adding paragraph (d) to read as follows:

§ 98.427 Records that must be retained.

* * * * *

(d) Facilities subject to § 98.426(h) must retain records of CO_2 in metric tons that is transferred to each subpart RR facility.

[FR Doc. 2015–22837 Filed 10–22–15; 8:45 am]

BILLING CODE 6560–50–P

FEDERAL REGISTER

Vol. 80 Friday,

No. 205 October 23, 2015

Book 2 of 2 Books

Pages 64661–65120

Part III

Environmental Protection Agency

40 CFR Part 60

Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units; Final Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[EPA–HQ–OAR–2013–0602; FRL–9930–65–OAR]

RIN 2060–AR33

Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: In this action, the Environmental Protection Agency (EPA) is establishing final emission guidelines for states to follow in developing plans to reduce greenhouse gas (GHG) emissions from existing fossil fuel-fired electric generating units (EGUs). Specifically, the EPA is establishing: Carbon dioxide (CO_2) emission performance rates representing the best system of emission reduction (BSER) for two subcategories of existing fossil fuel-fired EGUs—fossil fuel-fired electric utility steam generating units and stationary combustion turbines; state-specific CO_2 goals reflecting the CO_2 emission performance rates; and guidelines for the development, submittal and implementation of state plans that establish emission standards or other measures to implement the CO_2 emission performance rates, which may be accomplished by meeting the state goals. This final rule will continue progress already underway in the U.S. to reduce CO_2 emissions from the utility power sector.

DATES: This final rule is effective on December 22, 2015.

ADDRESSES: *Docket.* The EPA has established a docket for this action under Docket No. EPA–HQ–OAR–2013–0602. 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.,* confidential business information (CBI) or other information for which disclosure is restricted by statute). Certain other material, such as copyrighted material, will be publicly available only in hard copy. Publicly available docket materials are available either electronically in *http://www.regulations.gov* or in hard copy at the EPA Docket Center, EPA 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 federal 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 additional information about the EPA's public docket, visit the EPA Docket Center homepage at *http://www2.epa.gov/dockets.*

World Wide Web. In addition to being available in the docket, an electronic copy of this final rule will be available on the World Wide Web (WWW). Following signature, a copy of this final rule will be posted at the following address: *http://www.epa.gov/cleanpowerplan/.* A number of documents relevant to this rulemaking, including technical support documents (TSDs), a legal memorandum, and the regulatory impact analysis (RIA), are also available at *http://www.epa.gov/cleanpowerplan/.* These and other related documents are also available for inspection and copying in the EPA docket for this rulemaking.

FOR FURTHER INFORMATION CONTACT: Ms. Amy Vasu, Sector Policies and Programs Division (D205–01), U.S. EPA, Research Triangle Park, NC 27711; telephone number (919) 541–0107, facsimile number (919) 541–4991; email address: *vasu.amy@epa.gov* or Mr. Colin Boswell, Measurements Policy Group (D243–05), Sector Policies and Programs Division, U.S. EPA, Research Triangle Park, NC 27711; telephone number (919) 541–2034, facsimile number (919) 541–4991; email address: *boswell.colin@epa.gov.*

SUPPLEMENTARY INFORMATION:

Acronyms. A number of acronyms and chemical symbols are used in this preamble. While this may not be an exhaustive list, to ease the reading of this preamble and for reference purposes, the following terms and acronyms are defined as follows:

ACEEE American Council for an Energy-Efficient Economy
AEO Annual Energy Outlook
AFL-CIO American Federation of Labor and Congress of Industrial Organizations
ASTM American Society for Testing and Materials
BSER Best System of Emission Reduction
Btu/kWh British Thermal Units per Kilowatt-hour
CAA Clean Air Act
CBI Confidential Business Information
CCS Carbon Capture and Storage (or Sequestration)
CEIP Clean Energy Incentive Program
CEMS Continuous Emissions Monitoring System
CHP Combined Heat and Power
CO_2 Carbon Dioxide
DOE U.S. Department of Energy
ECMPS Emission Collection and Monitoring Plan System
EE Energy Efficiency
EERS Energy Efficiency Resource Standard
EGU Electric Generating Unit
EIA Energy Information Administration
EM&V Evaluation, Measurement and Verification
EO Executive Order
EPA Environmental Protection Agency
FERC Federal Energy Regulatory Commission
ERC Emission Rate Credit
FR Federal Register
GHG Greenhouse Gas
GW Gigawatt
HAP Hazardous Air Pollutant
HRSG Heat Recovery Steam Generator
IGCC Integrated Gasification Combined Cycle
IPCC Intergovernmental Panel on Climate Change
IPM Integrated Planning Model
IRP Integrated Resource Plan
ISO Independent System Operator
kW Kilowatt
kWh Kilowatt-hour
lb CO_2/MWh Pounds of CO_2 per Megawatt-hour
LBNL Lawrence Berkeley National Laboratory
MMBtu Million British Thermal Units
MW Megawatt
MWh Megawatt-hour
NAAQS National Ambient Air Quality Standards
NAICS North American Industry Classification System
NAS National Academy of Sciences
NGCC Natural Gas Combined Cycle
NO_X Nitrogen Oxides
NRC National Research Council
NSPS New Source Performance Standard
NSR New Source Review
NTTAA National Technology Transfer and Advancement Act
OMB Office of Management and Budget
PM Particulate Matter
$PM_{2.5}$ Fine Particulate Matter
PRA Paperwork Reduction Act
PUC Public Utilities Commission
RE Renewable Energy
REC Renewable Energy Credit
RES Renewable Energy Standard
RFA Regulatory Flexibility Act
RGGI Regional Greenhouse Gas Initiative
RIA Regulatory Impact Analysis
RPS Renewable Portfolio Standard
RTO Regional Transmission Organization
SBA Small Business Administration
SCC Social Cost of Carbon
SIP State Implementation Plan
SO_2 Sulfur Dioxide
Tg Teragram (one trillion (10^{12}) grams)
TSD Technical Support Document
TTN Technology Transfer Network
UMRA Unfunded Mandates Reform Act of 1995
UNFCCC United Nations Framework Convention on Climate Change
USGCRP U.S. Global Change Research Program
VCS Voluntary Consensus Standard

Organization of This Document. The information presented in this preamble is organized as follows:

I. General Information

A. Executive Summary

1. Introduction

This final rule is a significant step forward in reducing greenhouse gas (GHG) emissions in the U.S. In this action, the EPA is establishing for the first time GHG emission guidelines for existing power plants. These final emission guidelines, which rely in large part on already clearly emerging growth in clean energy innovation, development and deployment, will lead to significant carbon dioxide (CO_2) emission reductions from the utility power sector that will help protect human health and the environment from the impacts of climate change. This rule establishes, at the same time, the foundation for longer term GHG emission reduction strategies necessary to address climate change and, in so doing, confirms the international leadership of the U.S. in the global effort to address climate change. In this final rule, we have taken care to ensure that achievement of the required emission reductions will not compromise the reliability of our electric system, or the affordability of electricity for consumers. This final rule is the result of unprecedented outreach and engagement with states, tribes, utilities, and other stakeholders, with stakeholders providing more than 4.3 million comments on the proposed rule. In this final rule, we have addressed the comments and concerns of states and other stakeholders while staying consistent with the law. As a result, we have followed through on our commitment to issue a plan that is fair, flexible and relies on the accelerating transition to cleaner power generation that is already well underway in the utility power sector.

Under the authority of Clean Air Act (CAA) section 111(d), the EPA is establishing CO_2 emission guidelines for existing fossil fuel-fired electric generating units (EGUs)—the Clean Power Plan. These final guidelines, when fully implemented, will achieve significant reductions in CO_2 emissions by 2030, while offering states and utilities substantial flexibility and latitude in achieving these reductions. In this final rule, the EPA is establishing a CO_2 emission performance rate for each of two subcategories of fossil fuel-fired EGUs—fossil fuel-fired electric steam generating units and stationary combustion turbines—that expresses the ''best system of emissions reduction . . . adequately demonstrated'' (BSER) for CO_2 from the power sector.[1] The EPA is also establishing state-specific rate-based and mass-based goals that reflect the subcategory-specific CO_2 emission performance rates and each state's mix of affected EGUs. The guidelines also provide for the development, submittal and implementation of state plans that implement the BSER—again, expressed as CO_2 emission performance rates—either directly by means of source-specific emission standards or other requirements, or through measures that achieve equivalent CO_2 reductions from the same group of EGUs.

States with one or more affected EGUs will be required to develop and implement plans that set emission standards for affected EGUs. The CAA section 111(d) emission guidelines that the EPA is promulgating in this action apply to only the 48 contiguous states and any Indian tribe that has been approved by the EPA pursuant to 40 CFR 49.9 as eligible to develop and implement a CAA section 111(d) plan.[2] Because Vermont and the District of Columbia do not have affected EGUs, they will not be required to submit a state plan. Because the EPA does not possess all of the information or analytical tools needed to quantify the BSER for the two non-contiguous states with otherwise affected EGUs (Alaska and Hawaii) and the two U.S. territories with otherwise affected EGUs (Guam and Puerto Rico), these emission guidelines do not apply to those areas, and those areas will not be required to submit state plans on the schedule required by this final action.

The emission standards in a state's plan may incorporate the subcategory-specific CO_2 emission performance rates set by the EPA or, in the alternative, may be set at levels that ensure that the state's affected EGUs, individually, in aggregate, or in combination with other measures undertaken by the state achieve the equivalent of the interim and final CO_2 emission performance rates between 2022 and 2029 and by 2030, respectively. State plans must also: (1) Ensure that the period for emission reductions from the affected EGUs begin no later than 2022, (2) show how goals for the interim and final periods will be met, (3) ensure that, during the period from 2022 to 2029, affected EGUs in the state collectively meet the equivalent of the interim subcategory-specific CO_2 emission performance rates, and (4) provide for periodic state-level demonstrations prior to and during the 2022–2029 period that will ensure required CO_2 emission reductions are being accomplished and no increases in emissions relative to each state's planned emission reduction trajectory are occurring. A Clean Energy Incentive Program (CEIP) will provide opportunities for investments in renewable energy (RE) and demand-side energy efficiency (EE) that deliver results in 2020 and/or 2021. The plans must be submitted to the EPA in 2016, though an extension to 2018 is available to allow for the completion of stakeholder and administrative processes.

The EPA is promulgating: (1) Subcategory-specific CO_2 emission performance rates, (2) state rate-based goals, and (3) state mass-based CO_2 goals that represent the equivalent of each state's rate-based goal. This will facilitate states' choices in developing their plans, particularly for those seeking to adopt mass-based allowance trading programs or other statewide policy measures as well as, or instead of, source-specific requirements. The EPA received significant comment to the effect that mass-based allowance trading was not only highly familiar to states and EGUs, but that it could be more readily applied than rate-based trading for achieving emission reductions in ways that optimize affordability and electric system reliability.

In this summary, we discuss the purpose of this rule, the major provisions of the final rule, the context for the rulemaking, key changes from the proposal, the estimated CO_2 emission reductions, and the costs and benefits expected to result from full implementation of this final action. Greater detail is provided in the body of this preamble, the RIA, the response to comments (RTC) documents, and various TSDs and memoranda addressing specific topics.

2. Purpose of This Rule

The purpose of this rule is to protect human health and the environment by reducing CO_2 emissions from fossil fuel-fired power plants in the U.S. These plants are by far the largest domestic stationary source of emissions of CO_2, the most prevalent of the group of air pollutant GHGs that the EPA has determined endangers public health and welfare through its contribution to climate change. This rule establishes for the first time emission guidelines for existing power plants. These guidelines will lead to significant reductions in CO_2 emissions, result in cleaner generation from the existing power plant fleet, and support continued investments by the industry in cleaner power generation to ensure reliable, affordable electricity now and into the future.

Concurrent with this action, the EPA is also issuing a final rule that establishes CO_2 emission standards of performance for new, modified, and reconstructed power plants. Together, these rules will reduce CO_2 emissions by a substantial amount while ensuring that the utility power sector in the U.S. can continue to supply reliable and affordable electricity to all Americans using a diverse fuel supply. As with past EPA rules addressing air pollution from the utility power sector, these guidelines have been designed with a clear recognition of the unique features of this sector. Specifically, the agency recognizes that utilities provide an essential public service and are regulated and managed in ways unlike any other industrial activity. In providing assurances that the emission reductions required by this rule can be achieved without compromising continued reliable, affordable electricity, this final rule fully accounts for the critical service utilities provide.

As with past rules under CAA section 111, this rule relies on proven technologies and measures to set achievable emission performance rates that will lead to cost-effective pollutant emission reductions, in this case CO_2 emission reductions at power plants, across the country. In fact, the emission guidelines reflect strategies, technologies and approaches already in widespread use by power companies and states. The vast preponderance of the input we received from stakeholders is supportive of this conclusion.

States will play a key role in ensuring that emission reductions are achieved at a reasonable cost. The experience of

[1] Under CAA section 111(d), pursuant to 40 CFR 60.22(b)(5), states must establish, in their state plans, emission standards that reflect the degree of emission limitation achievable through the application of the ''best system of emission reduction'' that, taking into account the cost of achieving such reduction and any non-air quality health and environmental impacts and energy requirements, the Administrator determines has been adequately demonstrated (*i.e.,* the BSER). Under CAA section 111(a)(1) and (d), the EPA is authorized to determine the BSER and to calculate the amount of emission reduction achievable through applying the BSER. The state is authorized to identify the emission standard or standards that reflect that amount of emission reduction.

[2] In the case of a tribe that has one or more affected EGUs in its area of Indian country, the tribe has the opportunity, but not the obligation, to establish a CO_2 emission standard for each affected EGU located in its area of Indian country and a CAA section 111(d) plan for its area of Indian country. If the tribe chooses to establish its own plan, it must seek and obtain authority from the EPA to do so pursuant to 40 CFR 49.9. If it chooses not to seek this authority, the EPA has the responsibility to determine whether it is necessary or appropriate, in order to protect air quality, to establish a CAA section 111(d) plan for an area of Indian country where affected EGUs are located.

states in this regard is especially important because CAA section 111(d) relies on the well-established state-EPA partnership to accomplish the required CO_2 emission reductions. States will have the flexibility to choose from a range of plan approaches and measures, including numerous measures beyond those considered in setting the CO_2 emission performance rates, and this final rule allows and encourages states to adopt the most effective set of solutions for their circumstances, taking account of cost and other considerations. This rulemaking, which will be implemented through the state-EPA partnership, is a significant step that will reduce air pollution, in this case GHG emissions, in the U.S. At the same time, the final rule greatly facilitates flexibility for EGUs by establishing a basis for states to set trading-based emission standards and compliance strategies. The rule establishes this basis by including both uniform emission performance rates for the two subcategories of sources and also state-specific rate- and mass-based goals.

This final rule is a significant step forward in implementing the President's Climate Action Plan.[3] To address the far-reaching harmful consequences and real economic costs of climate change, the President's Climate Action Plan details a broad array of actions to reduce GHG emissions that contribute to climate change and its harmful impacts on public health and the environment. Climate change is already occurring in this country, affecting the health, economic well-being and quality of life of Americans across the country, and especially those in the most vulnerable communities. This CAA section 111(d) rulemaking to reduce GHG emissions from existing power plants, and the concurrent CAA section 111(b) rulemaking to reduce GHG emissions from new, modified, and reconstructed power plants, implement one of the strategies of the Climate Action Plan.

Nationwide, by 2030, this final CAA section 111(d) existing source rule will achieve CO_2 emission reductions from the utility power sector of approximately 32 percent from CO_2 emission levels in 2005.

The EPA projects that these reductions, along with reductions in other air pollutants resulting directly from this rule, will result in net climate and health benefits of $25 billion to $45 billion in 2030. At the same time, coal and natural gas will remain the two leading sources of electricity generation in the U.S., with coal providing about 27 percent of the projected generation and natural gas providing about 33 percent of the projected generation.

3. Summary of Major Provisions

a. *Overview.* The fundamental goal of this rule is to reduce harmful emissions of CO_2 from fossil fuel-fired EGUs in accordance with the requirements of the CAA. The June 2014 proposal for this rule was designed to meet this overarching goal while accommodating two important objectives. The first was to establish guidelines that reflect both the unique interconnected and interdependent manner in which the power system operates and the actions, strategies, and policies states and utilities have already been undertaking that are resulting in CO_2 emission reductions. The second objective was to provide states and utilities with broad flexibility and choice in meeting those requirements in order to minimize costs to ratepayers and to ensure the reliability of electricity supply. In this final rule, the EPA has focused on changes that, in addition to being responsive to the critical concerns and priorities of stakeholders, more fully accomplish these objectives.

While our consideration of public input and additional information has led to notable revisions from the emission guidelines we proposed in June 2014, the proposed guidelines remain the foundation of this final rule. These final guidelines build on the progress already underway to reduce the carbon intensity of power generation in the U.S., especially through the lowest carbon-intensive technologies, while reflecting the unique interconnected and interdependent system within which EGUs operate. Thus, the BSER, as determined in these guidelines, incorporates a range of CO_2-reducing actions, while at the same time adhering to the fundamental approach the EPA has relied on for decades in implementing section 111 of the CAA. Specifically, in making its BSER determination, the EPA examined not only actions, technologies and measures already in use by EGUs and states, but also deliberately incorporated in its identification of the BSER the unique way in which affected EGUs actually operate in providing electricity services. This latter feature of the BSER mirrors Congress' approach to regulating air pollution in this sector, as exemplified by Title IV of the CAA. There, Congress established a pollution reduction program specifically for fossil fuel-fired EGUs and designed the sulfur dioxide (SO_2) portion of that program with express recognition of the utility power sector's ability to shift generation among various EGUs, which enabled pollution reduction by increasing reliance on RE and even on demand-side EE. The result of our following Congress' recognition of the interdependent operation of EGUs within an interconnected grid is the incorporation in the BSER of measures, such as shifting generation to lower-emitting NGCC units and increased use of RE, that rely on the current interdependent operation of EGUs. As we noted in the proposal and note here as well, the EPA undertook an unprecedented and sustained process of engagement with the public and stakeholders. It is, in many ways, as a direct result of public discussion and input that the EPA came to recognize the substantial extent to which the BSER needed to account for the unique interconnected and interdependent operations of EGUs if it was to meet the criteria on which the EPA has long relied in making BSER determinations.

Equally important, these guidelines offer states and owners and operators of EGUs broad flexibility and latitude in complying with their obligations. Because affordability and electricity system reliability are of paramount importance, the rule provides states and utilities with time for planning and investment, which is instrumental to ensuring both manageable costs and system reliability, as well as to facilitating clean energy innovation. The final rule continues to express the CO_2 emission reduction requirements in terms of state goals, as well as in terms of emission performance rates for the two subcategories of affected EGUs, reflecting the particular mix of power generation in each state, and it continues to provide until 2030, fifteen years from the date of this final rule, for states and sources to achieve the CO_2 reductions. Numerous commenters, including most sources, states and energy agencies, indicated that this was a reasonable timeframe. The final guidelines also continue to provide an option where programs beyond those directly limiting power plant emission rates can be used for compliance (*i.e.,* policies, programs and other measures). The final rule also continues to allow, but not require, multi-state approaches. Finally, EPA took care to ensure that states could craft their own emissions reduction trajectories in meeting the interim goals included in this final rule.

b. *Opportunities for states.* As stated above, the final guidelines are designed to build on and reinforce progress by states, cities and towns, and companies on a growing variety of sustainable strategies to reduce power sector CO_2

[3] The President's Climate Action Plan, June 2013. *http://www.whitehouse.gov/sites/default/files/image/president27sclimateactionplan.pdf.*

emissions. States, in their CAA section 111(d) plans, will be able to rely on, and extend, programs they may already have created to address emissions of air pollutants, and in particular CO_2, from the utility power sector or to address the sector from an overall perspective. Those states committed to Integrated Resource Planning (IRP) will be able to establish their CO_2 reduction plans within that framework, while states with a more deregulated power sector system will be able to develop CO_2 reduction plans within that specific framework. Each state will have the opportunity to take advantage of a wide variety of strategies for reducing CO_2 emissions from affected EGUs, including demand-side EE programs and mass-based trading, which some suggested in their comments. The EPA and other federal entities, including the U.S. Department of Energy (DOE), the Federal Energy Regulatory Commission (FERC) and the U.S. Department of Agriculture (USDA), among others, are committed to sharing expertise with interested states as they develop and implement their plans.

States will be able to address the economic interests of their utilities and ratepayers by using the flexibilities in this final action to reduce costs to consumers, minimize stranded assets, and spur private investments in RE and EE technologies and businesses. They may also, if they choose, work with other states on multi-state approaches that reflect the regional structure of electricity operating systems that exists in most parts of the country and is critical to ensuring a reliable supply of affordable energy. The final rule gives states the flexibility to implement a broad range of approaches that recognize that the utility power sector is made up of a diverse range of companies of various sizes that own and operate fossil fuel-fired EGUs, including vertically integrated companies in regulated markets, independent power producers, rural cooperatives and municipally-owned utilities, some of which are likely to have more direct access than others to certain types of GHG emission reduction opportunities, but all of which have a wide range of opportunities to achieve reductions or acquire clean generation.

Again, with features that facilitate mass-based and/or interstate trading, the final guidelines also empower affected EGUs to pursue a broad range of choices for compliance and for integrating compliance action with the full range of their investments and operations.

c. *Main elements.* This final rule comprises three main elements: (1) Two subcategory-specific CO_2 emission performance rates resulting from application of the BSER to the two subcategories of affected EGUs; (2) state-specific CO_2 goals, expressed as both emission rates and as mass, that reflect the subcategory-specific CO_2 emission performance rates and each state's mix of affected EGUs the two performance rates; and (3) guidelines for the development, submittal and implementation of state plans that implement those BSER emission performance rates either through emission standards for affected EGUs, or through measures that achieve the equivalent, in aggregate, of those rates as defined and expressed in the form of the state goals.

In this final action, the EPA is setting emission performance rates, phased in over the period from 2022 through 2030, for two subcategories of affected fossil fuel-fired EGUs—fossil fuel-fired electric utility steam-generating units and stationary combustion turbines. These rates, applied to each state's particular mix of fossil fuel-fired EGUs, generate the state's carbon intensity goal for 2030 (and interim rates for the period 2022–2029). Each state will determine whether to apply these to each affected EGU or to take an alternative approach and meet either an equivalent statewide rate-based goal or statewide mass-based goal. The EPA does not prescribe how a state must meet the emission guidelines, but, if a state chooses to take the path of meeting a state goal, these final guidelines identify the methods that a state can or, in some cases, must use to demonstrate that the combination of measures and standards that the state adopts meets its state-level CO_2 goals. While the EPA accomplishes the phase-in of the interim goal by way of annual emission performance rates, states and EGUs may meet their respective emission reduction obligations ''on average'' over that period following whatever emission reduction trajectory they determine to pursue over that period.

CAA section 111(d) creates a partnership between the EPA and the states under which the EPA establishes emission guidelines and the states take the lead on implementing them by establishing emission standards or creating plans that are consistent with the EPA emission guidelines. The EPA recognizes that each state has differing policy considerations—including varying regional emission reduction opportunities and existing state programs and measures—and that the characteristics of the electricity system in each state (*e.g.,* utility regulatory structure and generation mix) also differ. Therefore, as in the proposal, each state will have the latitude to design a program to meet source-category specific emission performance rates or the equivalent statewide rate- or mass-based goal in a manner that reflects its particular circumstances and energy and environmental policy objectives. Each state can do so on its own, or a state can collaborate with other states and/or tribal governments on multi-state plans, or states can include in their plans the trading tools that EGUs can use to realize additional opportunities for cost savings while continuing to operate across the interstate system through which electricity is produced. A state would also have the option of adopting the model rules for either a rate- or a mass-based program that the EPA is proposing concurrently with this action.[4]

To facilitate the state planning process, this final rule establishes guidelines for the development, submittal, and implementation of state plans. The final rule describes the components of a state plan, the additional latitude states have in developing strategies to meet the emission guidelines, and the options they have in the timing of submittal of their plans. This final rule also gives states considerable flexibility with respect to the timeframes for plan development and implementation, as well as the choice of emission reduction measures. The final rule provides up to fifteen years for full implementation of all emission reduction measures, with incremental steps for planning and then for demonstration of CO_2 reductions that will ensure that progress is being made in achieving CO_2 emission reductions. States will be able to choose from a wide range of emission reduction measures, including measures that are not part of the BSER, as discussed in detail in section VIII.G of this preamble.

d. *Determining the BSER.* In issuing this final rulemaking, the EPA is implementing statutory provisions that have been in place since Congress first enacted the CAA in 1970 and that have been implemented pursuant to regulations promulgated in 1975 and followed in numerous subsequent CAA section 111 rulemakings. These requirements call on the EPA to develop emission guidelines that reflect the EPA's determination of the ''best system of emission reduction . . . adequately demonstrated'' for states to follow in

[4] The EPA's proposed CAA section 111(d) federal plan and model rules for existing fossil fuel-fired EGUs are being published concurrently with this final rule.

formulating plans to establish emission standards to implement the BSER.

As the EPA has done in making BSER determinations in previous CAA section 111 rulemakings, for this final BSER determination, the agency considered the types of strategies that states and owners and operators of EGUs are already employing to reduce the covered pollutant (in this case, CO_2) from affected sources (in this case, fossil fuel-fired EGUs).[5]

In so doing, as has always been the case, our considerations were not limited solely to specific technologies or equipment in hypothetical operation; rather, our analysis encompassed the full range of operational practices, limitations, constraints and opportunities that bear upon EGUs' emission performance, and which reflect the unique interconnected and interdependent operations of EGUs and the overall electricity grid.

In this final action, the agency has determined that the BSER comprises the first three of the four proposed ''building blocks,'' with certain refinements to the three building blocks. The three building blocks are:

1. Improving heat rate at affected coal-fired steam EGUs.
2. Substituting increased generation from lower-emitting existing natural gas combined cycle units for generation from higher-emitting affected steam generating units.
3. Substituting increased generation from new zero-emitting renewable energy generating capacity for generation from affected fossil fuel-fired generating units.

These three building blocks are approaches that are available to all affected EGUs, either through direct investment or operational shifts or through emissions trading where states, which must establish emission standards for affected EGUs, do so by incorporating emissions trading.[6] At the same time, and as we noted in the proposal, there are numerous other measures available to reduce CO_2 emissions from affected EGUs, and our determination of the BSER does not necessitate the use of the three building blocks to their maximum extent, or even at all. The building blocks and the BSER determination are described in detail in section V of this preamble.

e. *CO_2 state-level goals and subcategory-specific emission performance rates.*

(1) *Final CO_2 goals and emission performance rates.*

In this action, the EPA is establishing CO_2 emission performance rates for two subcategories of affected EGUs—fossil fuel-fired electric utility steam generating units and stationary combustion turbines. For fossil fuel-fired steam generating units, we are finalizing an emission performance rate of 1,305 lb CO_2/MWh. For stationary combustion turbines, we are finalizing an emission performance rate of 771 lb CO_2/MWh. As we did at proposal, for each state, we are also promulgating rate-based CO_2 goals that are the weighted aggregate of the emission performance rates for the state's EGUs. To ensure that states and sources can choose additional alternatives in meeting their obligations, the EPA is also promulgating each state's goal expressed as a CO_2 mass goal. The inclusion of mass-based goals, along with information provided in the proposed federal plan and model rules that are being issued concurrently with this rule, paves the way for states to implement mass-based trading, as some states have requested, reflecting their view that mass-based trading provides significant advantages over rate-based trading.

Affected EGUs, individually, in aggregate, or in combination with other measures undertaken by the state, must achieve the equivalent of the CO_2 emission performance rates, expressed via the state-specific rate- and mass-based goals, by 2030.

(2) *Interim CO_2 emission performance rates and state-specific goals.*

The best system of emission reduction includes both the measures for reducing CO_2 emissions and the timeframe over which they can be implemented. In this final action, the EPA is establishing an 8-year interim period, beginning in 2022 instead of 2020, over which to achieve the full required reductions to meet the CO_2 performance rates, a commencement date more than six years from October 23, 2015, the date of this rulemaking. This 8-year interim period from 2022 through 2029 is separated into three steps, 2022–2024, 2025–2027, and 2028–2029, each associated with its own interim CO_2 emission performance rates. The interim steps are presented both in terms of emission performance rates for the two subcategories of affected EGUs and in terms of state goals, expressed both as a rate and as a mass. A state may adopt emission standards for its sources that are identical to these interim emission performance rates or, alternatively, adapt these steps to accommodate the timing of expected reductions, as long as the state's interim goal is met over the 8-year period.

f. *State plans.*[7]

In this action, the EPA is establishing final guidelines for states to follow in developing, submitting and implementing their plans. In developing plans, states will need to choose the type of plan they will develop. They will also need to include required plan components in their plan submittals, meet plan submittal deadlines, achieve the required CO_2 emission reductions over time, and provide for monitoring and periodic reporting of progress. As with the BSER determination, stakeholder comments have provided both data and recommendations to which these final guidelines are responsive.

(1) *Plan approaches.*

To comply with these emission guidelines, a state will have to ensure, through its plan, that the emission standards it establishes for its sources individually, in aggregate, or in combination with other measures undertaken by the state, represent the equivalent of the subcategory-specific CO_2 emission performance rates. This final rule includes several options for state plans, as discussed in the proposal and in many of the comments we received.

First, in the final rule, states may establish emission standards for their affected EGUs that mirror the uniform emission performance rates for the two subcategories of sources included in this final rule. They may also pursue alternative approaches that adopt emission standards that meet the

[5] The final emission guidelines for landfill gas emissions from municipal solid waste landfills, published on March 12, 1996, and amended on June 16, 1998 (61 FR 9905 and 63 FR 32743, respectively), provide an example, as the guidelines allow either of two approaches for controlling landfill gas—by recovering the gas as a fuel, for sale, and removing from the premises, or by destroying the organic content of the gas on the premises using a control device. Recovering the gas as a fuel source was a practice already being used by some affected sources prior to promulgation of the rulemaking.

[6] The EPA notes that, in quantifying the emission reductions that are achievable through application of the BSER, some building blocks will apply to some, but not all, affected EGUs. Specifically, building block 1 will apply to affected coal-fired steam EGUs, building block 2 will apply to all affected steam EGUs (both coal-fired and oil/gas-fired), and building block 3 will apply to all affected EGUs.

[7] The CAA section 111(d) emission guidelines apply to the 50 states, the District of Columbia, U.S. territories, and any Indian tribe that has been approved by the EPA pursuant to 40 CFR 49.9 as eligible to develop and implement a CAA section 111(d) plan. In this preamble, in instances where these governments are not specifically listed, the term ''state'' is used to represent them. Because Vermont and the District of Columbia do not have affected EGUs, they will not be required to submit a state plan. Because the EPA does not possess all of the information or analytical tools needed to quantify the BSER for the two non-contiguous states with affected EGUs (Alaska and Hawaii) and the two U.S. territories with affected EGUs (Guam and Puerto Rico), we are not finalizing emission performance rates in those areas at this time, and those areas will not be required to submit state plans until we do.

uniform emission performance rates, or emission standards that meet either the rate-based goal promulgated for the state or the alternative mass-based goal promulgated for the state. It is for the purpose of providing states with these choices that the EPA is providing state-specific rate-based and mass-based goals equivalent to the emission performance rates that the EPA is establishing for the two subcategories of fossil fuel-fired EGUs. A detailed explanation of rate- and mass-based goals is provided in section VII of this preamble and in a TSD.[8] In developing its plan, each state and eligible tribe electing to submit a plan will need to choose whether its plan will result in the achievement of the CO_2 emission performance rates, statewide rate-based goals, or statewide mass-based goals by the affected EGUs.

The second major set of options provided in the final rule includes the types of measures states may rely on through the state plans. A state will be able to choose to establish emission standards for its affected EGUs sufficient to meet the requisite performance rates or state goal, thus placing all of the requirements directly on its affected EGUs, which we refer to as the ''emission standards approach.'' Alternatively, a state can adopt a ''state measures approach,'' which would result in the affected EGUs meeting the statewide mass-based goal by allowing a state to rely upon state-enforceable measures on entities other than affected EGUs, in conjunction with any federally enforceable emission standards the state chooses to impose on affected EGUs. With a state measures approach, the plan must also include a contingent backstop of federally enforceable emission standards for affected EGUs that fully meet the emission guidelines and that would be triggered if the plan failed to achieve the required emission reductions on schedule. A state would have the option of basing its backstop emission standards on the model rule, which focuses on the use of emissions trading as the core mechanism and which the EPA is proposing today. A state that adopts a state measures approach must use its mass CO_2 emission goal as the metric for demonstrating plan performance.

The final rule requires that the state plan submittal include a timeline with all of the programmatic plan milestone steps the state will take between the time of the state plan submittal and the year 2022 to ensure that the plan is effective as of 2022. States must submit a report to the EPA in 2021 that demonstrates that the state has met the programmatic plan milestone steps that the state indicated it would take during the period from the submittal of the final plan through the end of 2020, and that the state is on track to implement the approved state plan as of January 1, 2022.

The plan must also include a process for reporting on plan implementation, progress toward achieving CO_2 emission reductions, and implementation of corrective actions, in the event that the state fails to achieve required emission levels in a timely fashion. Beginning January 1, 2025, and then January 1, 2028, January 1, 2030, and then every two calendar years thereafter, the state will be required to compare emission levels achieved by affected EGUs in the state with the emission levels projected in the state plan and report the results of that comparison to the EPA by July 1 of those calendar years.

Existing state programs can be aligned with the various state plan options further described in Section VIII. A state plan that uses one of the finalized model rules, which the EPA is proposing concurrently with this action, could be presumptively approvable if the state plan meets all applicable requirements.[9] The plan guidelines provide the states with the ability to achieve the full reductions over a multi-year period, through a variety of reduction strategies, using state-specific or multi-state approaches that can be achieved on either a rate or mass basis. They also address several key policy considerations that states can be expected to contemplate in developing their plans.

State plan approaches and plan guidelines are explained further in section VIII of this preamble.

(2) *State plan components and approvability criteria.*

The EPA's implementing regulations provide certain basic elements required for state plans submitted pursuant to CAA section 111(d).[10] In the proposal, the EPA identified certain additional elements that should be contained in state plans. In this final action, in response to comments, the EPA is making several revisions to the components required in a state plan submittal and is also incorporating the approvability criteria into the final list of components required in a state plan submittal. In addition, we have organized the state plan components to reflect: (1) Components required for all state plan submittals; (2) additional components required for the emission standards approach; and (3) additional components required for the state measures approach.

All state plans must include the following components:

- Description of the plan
- Applicability of state plans to affected EGUs
- Demonstration that the plan submittal is projected to achieve the state's CO_2 emission performance rates or state CO_2 goal[11]
- Monitoring, reporting and recordkeeping requirements for affected EGUs
- State recordkeeping and reporting requirements
- Public participation and certification of hearing on state plan
- Supporting documentation

Also, in submitting state plans, states must provide documentation demonstrating that they have considered electric system reliability in developing their plans.

Further, in this final rule, the EPA is requiring states to demonstrate how they are meaningfully engaging all stakeholders, including workers and low-income communities, communities of color, and indigenous populations living near power plants and otherwise potentially affected by the state's plan. In their plan submittals, states must describe their engagement with their stakeholders, including their most vulnerable communities. The participation of these communities, along with that of ratepayers and the public, can be expected to help states ensure that state plans maintain the affordability of electricity for all and preserve and expand jobs and job opportunities as they move forward to develop and implement their plans.

State plan submittals using the emission standards approach must also include:

- Identification of each affected EGU; identification of federally enforceable emission standards for the affected EGUs; and monitoring, recordkeeping and reporting requirements.
- Demonstrations that each emission standard will result in reductions that are quantifiable, non-duplicative, permanent, verifiable, and enforceable.

State plan submittals using the state measures approach must also include:

- Identification of each affected EGU; identification of federally enforceable emission standards for affected EGUs (if applicable); identification of backstop of

[8] The CO_2 Emission Performance Rate and Goal Computation TSD for the CPP Final Rule, available in the docket for this rulemaking.

[9] The EPA would take action on such a state plan through independent notice and comment rulemaking.

[10] 40 CFR 60.23.

[11] A state that chooses to set emission standards that are identical to the emission performance rates for both the interim period and in 2030 and beyond need not identify interim state goals nor include a separate demonstration that its plan will achieve the state goals.

federally enforceable emission standards; and monitoring, recordkeeping and reporting requirements.

• Identification of each state measure and demonstration that each state measure will result in reductions that are quantifiable, non-duplicative, permanent, verifiable, and enforceable.

In addition to these requirements, each state plan must follow the EPA implementing regulations at 40 CFR 60.23.

(3) *Timing and process for state plan submittal and review.*

Because of the compelling need for actions to begin the steps necessary to reduce GHG emissions from EGUs, the EPA proposed that states submit their plans within 13 months of the date of this final rule and that reductions begin in 2020. In light of the comments received and in order to provide maximum flexibility to states while still taking timely action to reduce CO_2 emissions, in this final rule the EPA is allowing for a 2-year extension until September 6, 2018, for both individual and multi-state plans, to provide a total of 3 years for states to submit a final plan if an extension is received. Specifically, the final rule requires each state to submit a final plan by September 6, 2016. Since some states may need more than one year to complete all of the actions needed for their final state plans, including technical work, state legislative and rulemaking activities, a robust public participation process, coordination with third parties, coordination among states involved in multi-state plans, and consultation with reliability entities, the EPA is allowing an optional two-phased submittal process for state plans. If a state needs additional time to submit a final plan, then the state may request an extension by submitting an initial submittal by September 6, 2016. For the extension to be granted, the initial submittal must address three required components sufficiently to demonstrate that a state is able to undertake steps and processes necessary to timely submit a final plan by the extended date of September 6, 2018. These components are: An identification of final plan approach or approaches under consideration, including a description of progress made to date; an appropriate explanation for why the state needs additional time to submit a final plan beyond September 6, 2016; and a demonstration of how they have been engaging with the public, including vulnerable communities, and a description of how they intend to meaningfully engage with community stakeholders during the additional time (if an extension is granted) for development of the final plan, as described in section VIII.E of this preamble. As further described in section VIII.B of this preamble, the EPA is establishing a CEIP in order to promote early action. States' participation in the CEIP is optional. In order for a state to participate in the program, it must include in its initial submittal, if applicable, a non-binding statement of intent to participate in the CEIP; if a state is submitting a final plan by September 6, 2016, it must include such a statement of intent as part of its supporting documentation for the plan.

If the initial submittal includes those components and if the EPA does not notify the state that the initial submittal does not contain the required components, then, within 90 days of the submittal, the extension of time to submit a final plan will be deemed granted. A state will then have until no later than September 6, 2018, to submit a final plan. The EPA will also be working with states during the period after they make their initial submittals and provide states with any necessary information and assistance during the 90-day period. Further, states participating in a multi-state plan may submit a single joint plan on behalf of all of the participating states.

States and tribes that do not have any affected EGUs in their jurisdictional boundaries may provide emission rate credits (ERCs) to adjust CO_2 emissions, provided they are connected to the contiguous U.S. grid and meet other requirements for eligibility. There are certain limitations and restrictions for generating ERCs, and these, as well as associated requirements, are explained in section VIII of this preamble.

Following submission of final plans, the EPA will review plan submittals for approvability. Given a similar timeline accorded under section 110 of the CAA, and the diverse approaches states may take to meet the CO_2 emission performance rates or equivalent statewide goals in the emission guidelines, the EPA is extending the period for EPA review and approval or disapproval of plans from the four-month period provided in the EPA implementing regulations to a twelve-month period. This timeline will provide adequate time for the EPA to review plans and follow notice-and-comment rulemaking procedures to ensure an opportunity for public comment. The EPA, especially through our regional offices, will be available to work with states as they develop their plans, in order to make review of submitted plans more straightforward and to minimize the chances of unexpected issues that could slow down approval of state plans.

(4) *Timing for implementing the CO_2 emission guidelines.*

The EPA recognizes that the measures states and utilities have been and will be taking to reduce CO_2 emissions from existing EGUs can take time to implement. We also recognize that investments in low-carbon intensity and RE and in EE strategies are currently underway and in various stages of planning and implementation widely across the country. We carefully reviewed information submitted to us regarding the feasible timing of various measures and identifying concerns that the required CO_2 emission reductions could not be achieved as early as 2020 without compromising electric system reliability, imposing unnecessary costs on ratepayers, and requiring investments in more carbon-intensive generation, while diverting investment in cleaner technologies. The record is compelling. To respond to these concerns and to reflect the period of time required for state plan development and submittal by states, review and approval by the EPA, and implementation of approved plans by states and affected EGUs, the EPA is determining in this final rule that affected EGUs will be required to begin to make reductions by 2022, instead of 2020, as proposed, and meet the final CO_2 emission performance rates or equivalent statewide goals by no later than 2030. The EPA is establishing an 8-year interim period that begins in 2022 and goes through 2029, and which is separated into three steps, 2022–2024, 2025–2027, and 2028–2029, each associated with its own interim goal. Affected EGUs must meet each of the interim period step 1, 2, and 3 CO_2 emission performance rates, or, following the emissions reduction trajectory designed by the state itself, must meet the equivalent statewide interim period goals, on average, that a state may establish over the 8-year period from 2022–2029. The CAA section 111(d) plan must include those specific requirements. Affected EGUs must also achieve the final CO_2 performance rates or the equivalent statewide goal by 2030 and maintain that level subsequently. This approach reflects adjustments to the timeframe over which reductions must be achieved that mirror the determination of the final BSER, which incorporates the phasing in of the BSER measures in keeping with the achievability of those measures. The agency believes that this approach to timing is reasonable and appropriate, is consistent with many of the comments we received, and will best support the optimization of overall CO_2 reductions, ratepayer affordability and electricity system reliability.

The EPA recognizes that successfully achieving reductions by 2022 will be facilitated by actions and investments that yield CO_2 emission reductions prior to 2022. The final guidelines include provisions to encourage early actions. States will be able to take advantage of the impacts of early investments that occur prior to the beginning of a plan performance period. Under a mass-based plan, those impacts will be reflected in reductions in the reported CO_2 emissions of affected EGUs during the plan performance period. Under a rate-based plan, states may recognize early actions implemented after 2012 by crediting MWh of electricity generation and savings that are achieved by those measures during the interim and final plan performance periods. This provision is discussed in section VIII.K of the preamble.

In addition, to encourage early investments in RE and demand-side EE, the EPA is establishing the CEIP. Through this program, detailed in section VIII.B of this preamble, states will have the opportunity to award allowances and ERCs to qualified providers that make early investments in RE, as well as in demand-side EE programs implemented in low-income communities. Those states that take advantage of this option will be eligible to receive from the EPA matching allowances or ERCs, up to a total for all states that represents the equivalent of 300 million short tons of CO_2 emissions.

The EPA will address design and implementation details of the CEIP in a subsequent action. Prior to doing so, the EPA will engage with states, utilities and other stakeholders to gather information regarding their interests and priorities with regard to implementation of the CEIP.

The CEIP can play an important role in supporting one of the critical policy benefits of this rule. The incentives and market signal generated by the CEIP can help sustain the momentum toward greater RE investment in the period between now and 2022 so as to offset any dampening effects that might be created by setting the period for mandatory reductions to begin in 2022, two years later than at proposal.

(5) *Community and environmental justice considerations.*

Climate change is an environmental justice issue. Low-income communities and communities of color already overburdened by pollution are disproportionately affected by climate change and are less resilient than others to adapt to or recover from climate-change impacts. While this rule will provide broad benefits to communities across the nation by reducing GHG emissions, it will be particularly beneficial to populations that are disproportionately vulnerable to the impacts of climate change and air pollution.

Conventional pollutants emitted by power plants, such as particulate matter (PM), SO_2, hazardous air pollutants (HAP), and nitrogen oxides (NO_x), will also be reduced as the plants reduce their carbon emissions. These pollutants can have significant adverse local and regional health impacts. The EPA analyzed the communities in closest proximity to power plants and found that they include a higher percentage of communities of color and low-income communities than national averages. We thus expect an important co-benefit of this rule to be a reduction in the adverse health impacts of air pollution on these low-income communities and communities of color. We refer to these communities generally as ''vulnerable'' or ''overburdened,'' to denote those communities least resilient to the impacts of climate change and central to environmental justice considerations.

While pollution will be cut from power plants overall, there may be some relatively small number of coal-fired plants whose operation and corresponding emissions increase as energy providers balance energy production across their fleets to comply with state plans. In addition, a number of the highest-efficiency natural gas-fired units are also expected to increase operations, but they have correspondingly low carbon emissions and are also characterized by low emissions of the conventional pollutants that contribute to adverse health effects in nearby communities and regionally. The EPA strongly encourages states to evaluate the effects of their plans on vulnerable communities and to take the steps necessary to ensure that all communities benefit from the implementation of this rule. In order to identify whether state plans are causing any adverse impacts on overburdened communities, mindful that substantial overall reductions, nevertheless, may be accompanied by potential localized increases, the EPA intends to perform an assessment of the implementation of this rule to determine whether it and other air quality rules are leading to improved air quality in all areas or whether there are localized impacts that need to be addressed.

Effective engagement between states and affected communities is critical to the development of state plans. The EPA encourages states to identify communities that may be currently experiencing adverse, disproportionate impacts of climate change and air pollution, how state plan designs may affect them, and how to most effectively reach out to them. This final rule requires that states include in their initial submittals a description of how they engaged with vulnerable communities as they developed their initial submittals, as well as the means by which they intend to involve communities and other stakeholders as they develop their final plans. The EPA will provide training and other resources for states and communities to facilitate meaningful engagement.

In addition to the benefits for vulnerable communities from reducing climate change impacts and effects of conventional pollutant emissions, this rule will also help communities by moving the utility industry toward cleaner generation and greater EE. The federal government is committed to ensuring that all communities share in these benefits.

The EPA also encourages states to consider how they may incorporate approaches already used by other states to help low-income communities share in the investments in infrastructure, job creation, and other benefits that RE and demand-side EE programs provide, have access to financial assistance programs, and minimize any adverse impacts that their plans could have on communities. To help support states in taking concrete actions that provide economic development, job and electricity bill-cutting benefits to low-income communities directly, the EPA has designed the CEIP specifically to target the incentives it creates on investments that benefit low-income communities.

Community and environmental justice considerations are discussed further in section IX of this preamble.

(6) *Addressing employment concerns.*

In addition, the EPA encourages states in designing their state plans to consider the effects of their plans on employment and overall economic development to assure that the opportunities for economic growth and jobs that the plans offer are realized. To the extent possible, states should try to assure that communities that can be expected to experience job losses can also take advantage of the opportunities for job growth or otherwise transition to healthy, sustainable economic growth. The President has proposed the POWER+ Plan to help communities impacted by power sector transition. The POWER+ plan invests in workers and jobs, addresses important legacy costs in coal country, and drives development of coal technology.[12] Implementation of one key part of the POWER+ Plan, the Partnerships for Opportunity and Workforce and Economic Revitalization (POWER) initiative, has already begun. The POWER initiative specifically targets economic and workforce development assistance to communities affected by ongoing changes in the coal industry and the utility power sector.[13]

(7) *Electric system reliability.*

In no small part thanks to the comments we received and our extensive consultation with key agencies responsible for reliability, including FERC and DOE, among others, along with EPA's longstanding principles in setting emission standards for the utility power sector, these guidelines reflect the paramount importance of ensuring electric system reliability. The input we received on this issue focused heavily on the extent of the reductions required at the beginning of the interim period, proposed as 2020. We are addressing these concerns in large part by moving the beginning of the period for mandatory reductions under the program from 2020 to 2022 and significantly adjusting the interim goals so that they provide a less abrupt initial reduction expectation. This, in turn, will provide states and utilities with a great deal more latitude in determining their emission reduction trajectories over the interim period. As a result, there will be more time for planning, consultation and decision making in the formulation of state plans and in EGUs' choice of compliance strategies, all within the existing extensive structure of energy planning at the state and regional levels. These adjustments in the interim goals are supported by the information in the record concerning the time needed to develop and implement reductions under the BSER. In addition, the various forms of flexibility retained and enhanced in this final rule, including opportunities for trading within and between states, and other multi-state compliance approaches, will further support electric system reliability.

The final guidelines address electric system reliability in several additional important ways. Numerous commenters urged us to include, as part of the plan development or approval process, input from review by energy regulatory agencies and reliability entities. In the final rule, we are requiring that each state demonstrate in its final state plan submittal that it has considered reliability issues in developing its plan. Second, we recognize that issues may arise during the implementation of the guidelines that may warrant adjustments to a state's plan in order to maintain electric system reliability. The final guidelines make clear that states have the ability to propose amendments to approved plans in the event that unanticipated and significant electric system reliability challenges arise and compel affected EGUs to generate at levels that conflict with their compliance obligations under those plans.

As a final element of reliability assurance, the rule also provides for a reliability safety valve for individual sources where there is a conflict between the requirements the state plan imposes on a specific affected EGU and the maintenance of electric system reliability in the face of an extraordinary and unanticipated event that presents substantial reliability concerns.

We anticipate that these situations will be extremely rare because the states have the flexibility to craft requirements for their EGUs that will provide long averaging periods and/or compliance mechanisms, such as trading, whose inherent flexibility will make it unlikely that an individual unit will find itself in this kind of situation. As one example, under compliance regimes that allow individual EGUs to establish compliance through the acquisition and holding of allowances or ERCs equal to their emissions, an EGU's need to continue to operate—and emit—for the purposes of ensuring system reliability will not put the EGU into non-compliance, provided, of course, it obtains the needed allowances or credits in a timely fashion. We, nevertheless, agree with many commenters that it is prudent to provide an electric system reliability safety valve as a precaution.

Finally, the EPA, DOE and FERC have agreed to coordinate their efforts, at the federal level, to help ensure continued reliable electricity generation and transmission during the implementation of the final rule. The three agencies have set out a memorandum that reflects their joint understanding of how they will work together to monitor implementation, share information, and to resolve any difficulties that may be encountered.

As a result of the many features of this final rule that provide states and affected EGUs with meaningful time and decision making latitude, we believe that the comprehensive safeguards already in place in the U.S. to ensure electric system reliability will continue to operate effectively as affected EGUs reduce their CO_2 emissions under this program.

(8) *Outreach and resources for stakeholders.*

To provide states, U.S. territories, tribes, utilities, communities, and other interested stakeholders with understanding about the rule requirements, and to provide efficiencies where possible and reduce the cost and administrative burden, the EPA will continue to work with states, tribes, territories, and stakeholders to provide information and address questions about the final rule. Outreach will include opportunities for states and tribes to participate in briefings, teleconferences, and meetings about the final rule. The EPA's ten regional offices will continue to be the entry point for states, tribes and territories to ask technical and policy questions. The agency will host (or partner with appropriate groups to co-host) a number of webinars about various components of the final rule; these webinars are planned for the first two months after the final rule is issued. The EPA will also offer consultations with tribal governments. The EPA will continue outreach throughout the plan development and submittal process. The EPA will use information from this outreach process to inform the training and other tools that will be of most use to the state, tribes, and territories that are implementing the final rule.

The EPA has worked with communities, states, tribes and relevant associations to develop an extensive training plan that will continue in the months after the Clean Power Plan is finalized. The EPA has assembled resources from a variety of sources to create a comprehensive training curriculum for those implementing this rule. Recorded presentations from the EPA, DOE and other federal entities will be available for communities, states, and others involved in composing and participating in the development of state plans. This curriculum is available online at EPA's Air Pollution Training Institute.

The EPA also expects to issue guidance on specific topics. As guidance documents, tools, templates and other resources become available, the EPA, in consultation with DOE and other federal agencies, will continue to make these resources available via a dedicated Web site.[14]

We intend to continue to work actively with states and tribes, as appropriate, to provide information and technical support that will be helpful to

[12] *https://www.whitehouse.gov/the-press-office/2015/03/27/fact-sheet-partnerships-opportunity-and-workforce-and-economic-revitaliz.*

[13] *http://www.eda.gov/power/.*

[14] www.epa.gov/cleanpowerplantoolbox.

them in developing and implementing their plans. The EPA will engage in formal consultations with tribal governments and provide training tailored to the needs of tribes and tribal governments.

Additional detail on aspects of the final rule is included in several technical support documents (TSDs) and memoranda that are available in the rulemaking docket.

4. Key Changes From Proposal

a. *Overview and highlights.* As noted earlier in this overview, the June 2014 proposal for the rule was designed to meet the fundamental goal of reducing harmful emissions of CO_2 from fossil fuel-fired EGUs in a manner consistent with the CAA requirements, while accommodating two important objectives. The first objective was to establish guidelines that reflect both the manner in which the power system operates and the actions and measures already underway across states and the utility power sector that are resulting in CO_2 emission reductions. The second objective was to provide states and utilities maximum flexibility, control and choice in meeting their compliance obligations. In this final rule, the EPA has focused on changes that, in addition to being responsive to the critical concerns and priorities of stakeholders, more fully accomplish these two crucial objectives.

To achieve these objectives, the June 2014 proposal featured several important elements: The building block approach for the BSER; state-specific, rather than source-specific, goals; a 10-year interim goal that could be met ''on average'' over the 10-year period between 2020 and 2029; and a ''portfolio'' option for state plans. These features were intended either to capture, in the emission guidelines, emission reduction measures already in widespread use or to maximize the range of choices that states and utilities could select in order to achieve their emission limitations at low cost while ensuring electric system reliability. In this final rule, we are retaining the key design elements of the proposal and making certain adjustments to respond to a variety of very constructive comments on ways that will implement the CAA section 111(d) requirements efficiently and effectively.

The building block approach is a key feature of the proposal that we are retaining in the final rule, but have refined to include only the first three building blocks and to reflect implementation of the measures encompassed in the building blocks on a broad regional grid-level. In the proposal, we expressed the emission limitation requirements reflecting the BSER in terms of the state goals in order to provide states with maximum flexibility and latitude. We viewed this as an important feature because each state has its own energy profile and state-specific policies and needs relative to the production and use of electricity. In the final rule, we extend that flexibility significantly in direct response to comments from states and utilities. The final rule establishes source-level emission performance rates for the source subcategories, while retaining state-level rate- and mass-based goals. One of the key messages conveyed by state and utility commenters was that the final rule should make it easier for states to adopt mass-based programs and for utilities accustomed to operating across broad multi-state grids to be able to avail themselves of more ''ready-made'' emissions trading regimes. The inclusion of both of these new features—mass-based state goals in addition to rate-based goals, and source-level emission performance rates for the two subcategories of sources—is intended to make it easier for states and utilities to achieve these outcomes. In fact, these additions, together with the model rules and federal plan being proposed concurrently with this rule, should demonstrate the relative ease with which states can adopt mass-based trading programs, including interstate mass-based programs that lend themselves to the kind of interstate compliance strategies so well suited for integration with the current interstate operations of the overall utility grid.

Many stakeholders conveyed to the EPA that the proposal's interim goals for the 2020–2029 period were designed in a way that defeated the EPA's objective of allowing states and utilities to shape their emission reduction trajectories. They pointed out that, in many cases, the timing and stringency of the states' interim goals could require actions that could result in high costs, threaten electric system reliability or hinder the deployment of renewable technology. In response, the EPA has revised the interim goals in two critical ways. First, the period for mandatory reductions begin in 2022 rather than 2020; second, in keeping with the BSER, emission reduction requirements are phased in more gradually over the interim period. These changes will allow states and utilities to delineate their own emission reduction trajectories so as to minimize costs and foster broader deployment of RE technologies. The value of these changes is demonstrated by our analysis of the final rule, which shows lower program costs, especially in the early years of the interim period, and greater RE deployment, relative to the analysis of the proposed rule. At the same time, this re-design of the interim goals, together with refinements we have made to state plan requirements and the inclusion of a reliability safety valve, provide states, utilities and other entities with the ability to continue to guarantee system reliability.

b. *Outreach, engagement and comment record.* This final rule is the product of one of the most extensive and long-running public engagement processes the EPA has ever conducted, starting in the summer of 2013, prior to proposal, and continuing through December 2014, when the public comment period ended, and continuing beyond that with consultations and meetings with stakeholders. The result of this extensive consultation was millions of comments from stakeholders, which we have carefully considered over the past several months. The EPA gained crucial insights from the more than 4 million comments that the agency received on the proposal and associated documents leading to this final rulemaking. Comments were provided by stakeholders that include state environmental and energy officials, tribal officials, public utility commissioners, system operators, owners and operators of every type of power generating facility, other industry representatives, labor leaders, public health leaders, public interest advocates, community and faith leaders, and members of the public.

The insights gained from public comments contributed to the development of final emission guidelines that build on the proposal and the alternatives on which we sought comment. The modifications incorporated in the final guidelines are directly responsive to the comments we received from the many and diverse stakeholders. The improved guidelines reflect information and ideas that states and utilities provided to us about both the best approach to establishing CO_2 emission reduction requirements for EGUs and the most effective ways to create true flexibility for states and utilities in meeting these requirements. These final rules also reflect the results of EPA's robust consultation with federal, state and regional energy agencies and authorities, to ensure that the actions sources will take to reduce GHG emissions will not compromise electric system reliability or affordability of the U.S. electricity supply. Input and assistance from FERC and DOE have been particularly important in shaping some provisions in these final guidelines. At the same time, input from faith-based, community-based and environmental justice organizations, who provided thoughtful comments about the potential impacts of this rule on pollution levels in overburdened communities and economic impacts, including utility rates in low-income communities, is also reflected in this rule. The final rule also reflects our response to concerns raised by labor leaders regarding the potential effects on workers and communities of the transition away from higher-emitting power generation to lower- and zero-emitting power generation.

c. *Key changes.* The most significant changes in these final guidelines are: (1) The period for mandatory emission reductions beginning in 2022 instead of 2020 and a gradual application of the BSER over the 2022–2029 interim period, such that a state has substantial latitude in selecting its own emission reduction trajectory or ''glide path'' over that period, (2) a revised BSER determination that focuses on narrower generation options that do not include demand-side EE measures and that includes refinements to the building blocks, more complete incorporation in the BSER of the realities of electricity operations over the three regional interconnections, and up-to-date information about the cost and availability of clean generation options, (3) establishment of source-specific CO_2 emission performance rates that are uniform across the two fossil fuel-fired subcategories covered in these guidelines, as well as rate- and mass-based state goals, to facilitate emission trading, including interstate trading and, in particular, mass-based trading, (4) a variation on the proposal's ''portfolio'' option for state plans—called here the ''state measures'' approach—that continues to provide states flexibility while ensuring that all state plans have federally enforceable measures as a backstop, (5) additional, more flexible options for states and utilities to adopt multi-state compliance strategies, (6) an extension of up to two years available to all states for submittal of their final compliance plans following making initial submittals in 2016, (7) provisions to encourage actions that achieve early reductions, including a Clean Energy Incentive Program (CEIP), (8) a combination of provisions expressly designed to ensure electric system reliability, (9) the addition of employment considerations for states in plan development, and (10) the expansion of considerations and programs for low-income and vulnerable communities.

We provide summary explanations in the following paragraphs and more detailed explanations of all of these changes in later sections of this preamble and associated documents.

(1) *Mandatory reduction period beginning in 2022 and a gradual glide path.*

The proposal's mandatory emission reduction period beginning in 2020 and the trajectory of emission reduction requirements in the interim period were both the subjects of significant comment. Earlier this year, FERC conducted a series of technical conferences comprising one national session and three regional sessions. The information provided by workshop participants echoed much of the material that had been submitted to the comment record for this rulemaking. On May 15, 2015, the FERC Commissioners, drawing upon information highlighted at the technical conferences, transmitted to the EPA some suggestions for the final rule. In addition, via comments, states, utilities, and reliability entities asked us to ensure adequate time for them to implement strategies to achieve CO_2 reductions. They expressed concern that, in the proposal, at least some states would be required to reduce emissions in 2020 to levels that would require abrupt shifts in generation in ways that raised concerns about impacts to electric system reliability and ratepayer bills, as well as about stranded assets. To many commenters, the proposal's requirement for CO_2 emission reductions beginning in 2020, together with the stringency of the interim CO_2 goal, posed significant reliability implications, in particular. In this final rule, the agency is addressing these concerns, in part, by adjusting the compliance timeframe from a 10-year interim period that begins in 2020 to an 8-year interim period that begins in 2022, and by refining the approach for meeting interim CO_2 emission performance rates to be a gradual glide path separated into three steps, 2022–2024, 2025–2027, and 2028–2029, that is also achievable ''on average'' over the 8-year interim period. In response to the concerns of commenters that the proposal's 10-year interim target failed to afford sufficient flexibility, the final guidelines' approach will provide states with realistic options for customizing their emission reduction trajectories. Of equal importance, the approach provides more time for planning, consultation and decision making in the formulation of state plans and in EGUs' choices of compliance strategies. Both FERC's May 15, 2015 letter and the comment record, as well as other information sources, made it clear that providing sufficient time for planning and implementation was essential to ensuring electric system reliability.

The final guidelines' approach to the interim emission performance rates is the result of the application of the measures constituting the BSER in a more gradual way, reflecting stakeholder comments and information about the appropriate period of time over which those measures can be deployed consistent with the BSER factors of cost and feasibility. In addition to facilitating reliable system operations, these changes provide states and utilities with the latitude to consider a broader range of options to achieve the required reductions while addressing concerns about ratepayer impacts and stranded assets.

(2) *Revised BSER determination.*

Commenters urged the EPA to confine its BSER determination to actions that involve what they characterized as more ''traditional'' generation. While some stakeholders recognized demand-side EE as being an integral part of the electricity system, with many of the characteristics of more traditional generating resources, other stakeholders did not. As explained in section V.B.3.c.(8) below, our traditional interpretation and implementation of CAA section 111 has allowed regulated entities to produce as much of a particular good as they desire, provided that they do so through an appropriately clean (or low-emitting) process. While building blocks 1, 2, and 3 fall squarely within this paradigm, the proposed building block 4 does not. In view of this, since the BSER must serve as the foundation of the emission guidelines, the EPA has not included demand-side EE as part of the final BSER determination. Thus, neither the final guidelines' BSER determination nor the emission performance rates for the two subcategories of affected EGUs take into account demand-side EE. However, many commenters also urged the EPA to allow states and sources to rely on demand-side EE as an element of their compliance strategies, as demand-side EE is treated as functionally interchangeable with other forms of generation for planning and operational purposes, as EE measures are in widespread use across the country and provide energy savings that reduce emissions, lower electric bills, and lead to positive investments and job creation. We agree, and the final guidelines provide ample latitude for states and utilities to rely on demand-side EE in meeting emission reduction requirements.

In response to stakeholder comments on the first three building blocks and considerable data in the record, the EPA has made refinements to the building blocks, and these are reflected in the final BSER. Refinements include adoption of a modified approach to quantification of the RE component, exclusion of the proposed nuclear generation components, and adoption of a consistent regionalized approach to quantification of all three building blocks. The agency also recognizes the important functional relationship between the period of time over which measures are deployed and the stringency of emission limitations those measures can achieve practically and at reasonable cost. Therefore, the final BSER also reflects adjustments to the stringency of the building blocks, after consideration of more and less stringent levels, and refinements to the timeframe over which reductions must be achieved. Sections V.C through V.E of this preamble provide further information on the refinements made to the building blocks and the rationale for doing so.

Commenters pointed out—and practical experience confirms—what is widely known: That the utility power sector operates over regional interconnections that are not constrained by state borders. Across a variety of issues raised in the proposal, many commenters urged that the EPA take that reality into account in developing this final rule. Consequently, the BSER determination itself (as well as a number of new compliance features included in this final rule) and the resulting subcategory-specific emission performance rates take into account the grid-level operations of the source category.

The final guidelines' BSER determination also takes into account recent reductions in the cost of clean energy technology, as well as projections of continuing cost reductions, and continuing increases in RE deployment. We also updated the underlying analysis with the most recent Energy Information Administration (EIA) projections that show lower growth in electricity demand between 2020 and 2030 than previously projected. In keeping with these recent EIA projections, we expect the final guidelines will be more conducive to compliance, consistent with a strategy that allows for the cleanest power generation and greater CO_2 reductions in 2030 than the proposal. With a date of 2022, instead of 2020, as proposed, for the mandatory CO_2 emission reduction period to begin, the final guidelines reflect that the additional time aligns with the adoption of lower-cost clean technology and, thus, its incorporation in the BSER at higher levels. At the same time, the 2022–2029 interim period will more easily allow for companies to take advantage of improved clean energy technologies as potential least cost options.

(3) *Uniform emission performance rates.*

Some stakeholders commented that the proposal's approach of expressing the BSER in terms of state-specific goals deviated from the requirements of CAA section 111 and from previous new source performance standards (NSPS). The effect, they stated, was that the proposal created de facto emission standards for all affected EGUs but that these de facto standards varied widely depending on the state in which a given EGU happened to be located. Instead, these and other commenters stated, section 111 requires that EPA establish the BSER specifically for affected sources, rather than by means of merely setting state-specific goals, and that these standards be uniform. Still other commenters observed that the effect of the approach taken in the proposal of applying the BSER to each state's fleet was to put a greater burden of reductions on lower-emitting or less carbon-intensive states and a lesser emission reduction burden on sources and states that were higher-emitting or more carbon-intensive. This, they argued, was both inequitable and at odds with the way in which NSPS have been applied in the past, where the higher-emitting sources have made the greater and more cost-effective reductions, while lower-emitting sources, whose reduction opportunities tend to be less cost-effective, have been required to make fewer reductions to meet the applicable standard.

At the same time, state and utility commenters expressed concern that relying on state-specific goals and state-by-state planning could introduce complexity into the otherwise seamless integrated operation of affected EGUs across the multi-state grids on which system operators, states and utilities currently rely and intend to continue to rely. Accordingly, they recommended that the final guidelines facilitate emissions trading, in particular interstate trading, which would enable EGU operators to integrate compliance with CO_2 emissions limitations with facility and grid-level operations. These sets of comments intersected at the point at which they focused on the fact that it is at the source level at which the standard is set for NSPS and at the source level at which compliance must be achieved.

The EPA carefully considered these comments and while we believe that the approach we took at proposal was well-founded and reflected a number of important considerations, we have concluded that there is a way to address these concerns while expanding upon the advantages offered by the proposal. Accordingly, the final guidelines establish uniform rates for the two subcategories of sources—an approach that is valuable for creating greater equity between and among utilities and states with widely varying emission levels and for expanding the flexibility of the program, especially in ways that have been identified as important to utilities and states. Specifically, the final guidelines express the BSER by means of performance-based CO_2 emission rates that are uniform across each of two subcategories—fossil fuel-fired electric steam generating units and stationary combustion turbines—for the affected EGUs covered by the guidelines. The rates are determined, in part, by applying the methodology identified in the Notice of Data Availability (NODA) published on October 30, 2014, which was based on the proposal's building block approach. The final guidelines also maintain the approach adopted in the proposal of establishing state-level goals; in the final rule, those goals are equal to the weighted aggregate of the two emission performance rates as applied to the EGUs in each state.

This approach rectifies what would have been an inefficient, unintended outcome of putting the greater reduction burden on lower-emitting sources and states while exempting higher-emitting sources and states. Expressing the BSER by means of these rates also augments the range of options for both states and EGUs for securing needed flexibility. Inclusion of state goals creates latitude for states as to how they will meet the guidelines. States also may meet the guideline requirements by adopting the CO_2 emission performance rates as emission standards that apply to the affected EGUs in their jurisdiction. Such an approach would lend itself to the ready establishment of intra-state and interstate trading, with the uniform rate-based standards of performance established for each EGU as the basis for such trading. At the same time, as at proposal, each state also has the option of complying with these guidelines by adopting a plan that takes a different approach to setting standards of performance for its EGUs and/or by applying complementary or alternative measures to meet the state goal set by these guidelines—as either a rate or a mass total.

During the outreach process and through comments, a number of state officials and other stakeholders expressed concern that the EPA's approach at proposal necessitated or represented a significant intrusion into state-level energy policy-making, drawing the EPA well beyond the bounds of its CAA authority and expertise. In fact, these final guidelines are entirely respectful of the EPA's responsibility and authority to regulate sources of air pollution. Instead, by establishing and operating through uniform performance rates for the two subcategories of sources that can be applied by states at the individual source level and that can readily be implemented through emission standards that incorporate emissions trading, these final guidelines align with the approach Congress and the EPA have consistently taken to regulating emissions from this and other industrial sectors, namely setting source-level, source category-wide standards that individual sources can meet through a variety of technologies and measures.

We emphasize, at the same time, that while the final guidelines express the BSER by means of source-level CO_2 emission performance rates, as well as state-level goals, as at proposal, each state will have a goal reflecting its particular mix of sources, and the final guidelines retain the flexibility inherent in the proposal's state-specific goals approach (and, as discussed in section VIII of this preamble, enhanced in various ways). Thus, in keeping with the proposal's flexibility, states may choose to adopt either the emission performance rates as emission standards for their sources, set different but, in the aggregate, equivalent rates, or fulfill their obligations by meeting their respective individual state goals.

(4) *State plan approaches.*

Commenters expressed support for the objectives served by the ''portfolio'' option in the state plan approaches included at proposal, but many raised concerns about its legality, with respect, in particular, to the CAA's enforceability requirements. Some of these commenters identified a ''state commitment approach'' with backstop measures as a variation of the ''portfolio'' approach that would retain the benefits of the ''portfolio'' approach while resolving legal and enforceability concerns. In this final rule, in response to stakeholder comments on the portfolio approach and alternative approaches, the EPA is finalizing two approaches: A source-based ''emission standards'' approach, and a ''state measures'' approach. Through the latter, states may adopt a set of policies and programs, which would not be federally enforceable, except that any standards imposed on affected EGUs would be federally enforceable. In addition, states would be required to include federally enforceable backstop measures applicable to each affected EGU in the event that the measures included in the state plan failed to achieve the state plan's emissions reduction trajectory. Under these guidelines, states can implement the BSER through standards of performance incorporating the uniform performance rates or alternative but in the aggregate equivalent rates, or they can adopt plans that achieve in aggregate the equivalent of the subcategory-specific CO_2 emission performance rates by relying on other measures undertaken by the state that complement source-specific requirements or, save for the contingent backstop requirement, supplant them entirely. This revision provides consistency in the treatment of sources while still providing maximum flexibility for states to design their plans around reduction approaches that best suit their policy objectives.

(5) *Emission trading programs.*

Many state and utility commenters supported the use of mass-based and rate-based emission trading programs in state plans, including interstate emission trading programs, and either pointed out obstacles to establishing such programs or suggested approaches that would enhance states' and utilities' ability to create and participate in such programs.

Through a combination of features retained from the proposal and changes made to the proposal, these final guidelines provide states and utilities with a panoply of tools that greatly facilitate their putting in place and participating in emissions trading programs. These include: (1) Expressing BSER in uniform emission performance rates that states may rely on in setting emission standards for affected EGUs such that EGUs operating under such standards readily qualify to trade with affected EGUs in states that adopt the same approach, (2) promulgating state mass goals so that states can move quickly to establish mass-based programs such that their affected EGUs readily qualify to trade with affected EGUs in states that adopt the same approach, and (3) providing EPA resources and capacity to create a tracking system to support state emissions trading programs.

(6) *Extension of plan submittal date.*

Stakeholders, particularly states, provided compelling information establishing that it could take longer than the agency initially anticipated for the states to develop and submit their required plans. While the approach at proposal reflected the EPA's conclusion that it was essential to the environmental and economic purposes of this rulemaking that utilities and states establish the path towards emissions reductions as early as possible, we recognize commenters' concerns. To strike the proper balance, the EPA has developed a revised state plan submittal schedule. For states that cannot submit a final plan by September 6, 2016, the EPA is requiring those states to make an initial submittal by that date to assure that states begin to address the urgent needs for reductions quickly, and is providing until September 6, 2018, for states to submit a final plan, if an extension until that date is justified, to address the concern that a submitting state needs more time to develop comprehensive plans that reflect the full range of the state's and its stakeholders' interests.

(7) *Provisions to encourage early action.*

Many commenters supported providing incentives for states and utilities to deploy CO_2-reducing investments, such as RE and demand-side EE measures, as early as possible. We also received comments from stakeholders regarding the disproportionate burdens that some communities already bear, and stating that all communities should have equal access to the benefits of clean and affordable energy. The EPA recognizes the validity and importance of these perspectives, and as a result has determined to provide a program—called the CEIP—in which states may choose to participate.

The CEIP is designed to incentivize investment in certain RE and demand-side EE projects that commence construction, in the case of RE, or commence construction, in the case of demand-side EE, following the submission of a final state plan to the EPA, or after September 6, 2018, for states that choose not to submit a final state plan by that date, and that generate MWh (RE) or reduce end-use energy demand (EE) during 2020 and/or 2021. State participation in the program is optional.

Under the CEIP, a state may set aside allowances from the CO_2 emission budget it establishes for the interim plan performance period or may generate early action ERCs (ERCs are discussed in more detail in section VIII.K.2), and allocate these allowances or ERCs to eligible projects for the MWh those projects generate or the end-use energy savings they achieve in 2020 and/or 2021. For each early action allowance or ERC a state allocates to such projects, the EPA will provide the state with an appropriate number of matching allowances or ERCs for the state to allocate to the project. The EPA will match state-issued early action ERCs and allowances up to an amount that represents the equivalent of 300 million short tons of CO_2 emissions.

For a state to be eligible for a matching award of allowances or ERCs from the EPA, it must demonstrate that it will award allowances or ERCs only to ''eligible'' projects. These are projects that:

• Are located in or benefit a state that has submitted a final state plan that includes requirements establishing its participation in the CEIP;

• Are implemented following the submission of a final state plan to the EPA, or after September 6, 2018, for a state that chooses not to submit a complete state plan by that date;

• For RE: Generate metered MWh from any type of wind or solar resources;

• For EE: Result in quantified and verified electricity savings (MWh) through demand-side EE implemented in low-income communities; and

• Generate or save MWh in 2020 and/or 2021.

The following provisions outline how a state may award early action ERCs and allowances to eligible projects, and how the EPA will provide matching ERCs or allowances to states.

• For RE projects that generate metered MWh from any type of wind or solar resources: For every two MWh generated, the project will receive one early action ERC (or the equivalent number of allowances) from the state, and the EPA will provide one matching ERC (or the equivalent number of allowances) to the state to award to the project.

• For EE projects implemented in low-income communities: For every two MWh in end-use demand savings achieved, the project will receive two early action ERCs (or the equivalent number of allowances) from the state, and the EPA will provide two matching ERCs (or the equivalent number of allowances) to the state to award to the project.

Early action allowances or ERCs awarded by the state, and matching allowances or ERCs awarded by the EPA pursuant to the CEIP, may be used for compliance by an affected EGU with its emission standards and are fully transferrable prior to such use.

The EPA discusses the CEIP in the proposed federal plan rule and will address design and implementation details of the CEIP in a subsequent action. Prior to doing so, the EPA will engage with states, utilities and other stakeholders to gather information regarding their interests and priorities with regard to implementation of the CEIP.

(8) *Provisions for electric system reliability.*

A number of commenters stressed the importance of final guidelines that addressed the need to ensure that EGUs could meet their emission reduction requirements without being compelled to take actions that would undermine electric system reliability. As noted above, the EPA has consulted extensively with federal, regional and state energy agencies, utilities and many others about reliability concerns and ways to address them. The final guidelines support electric system reliability in a number of ways, some inherent in the improvements made in the program's design and some through specific provisions we have included in the final rule. Most important are the two key changes we made to the interim goal: Establishing 2022, instead of 2020, as the period for mandatory emission reductions begin and phasing in, over the 8-year period, emission performance rates such that the level of stringency of the emission performance rates in 2022–2024 is significantly less than that for the years 2028 and 2029. Since states and utilities need only to meet their interim goal ''on average'' over the 8-year period, these changes provide them with a great deal of latitude in determining for themselves their emission reduction trajectory—and they have additional time to do so. As a result, the final guidelines provide the ingredients that commenters, reliability entities and expert agencies told the EPA were essential to ensuring electric system reliability: Time and flexibility sufficient to allow for planning, implementation and the integration of actions needed to address reliability while achieving the required emissions reductions.

In addition, the final guidelines add a requirement, based on substantial input from experts in the energy field, for states to demonstrate that they have considered electric system reliability in developing their state plans. The final rule also offers additional opportunities that support electric system reliability, including opportunities for trading within and between states. The final guidelines also make clear that states can adjust their plans in the event that reliability challenges arise that need to be remedied by amending the state plan. In addition, the final rule includes a reliability safety valve to address situations where, because of an unanticipated catastrophic event, there is a conflict between the requirements imposed on an affected unit and the maintenance of reliability.

(9) *Approaches for addressing employment concerns.*

Some commenters brought to our attention the concerns of workers, their families and communities, particularly in coal-producing regions and states, that the ongoing shift toward lower-carbon electricity generation that the final rule reflects will cause harm to communities that are dependent on coal. Others had concerns about whether new jobs created as a result of actions taken pursuant to the final rule will allow for overall economic development. In the final rule, the EPA encourages states, in designing their state plans, to consider the effects of their plans on employment and overall economic development to assure that the opportunities for economic growth and jobs that the plans offer are manifest. We also identify federal programs, including the multi-agency Partnerships for Opportunity and Workforce and Economic Revitalization (POWER) Initiative.[15] The POWER Initiative is competitively awarding planning assistance and implementation grants with funding from the Department of Commerce, Department of Labor (DOL), Small Business Administration, and the Appalachian Regional Commission,[16] whose mission is to assist communities affected by changes in the coal industry and the utility power sector.

(10) *Community and environmental justice considerations.*

Many community leaders, environmental justice advocates, faith-based organizations and others commented that the benefits of this rule must be shared broadly across society and that undue burdens should not be imposed on low-income ratepayers. We agree. The federal government is taking significant steps to help low-income families and individuals gain access to RE and demand-side EE through new initiatives involving, for example, increasing solar energy systems in federally subsidized homes and supporting solar systems for others with low incomes. The final rule ensures that bill-lowering measures such as demand-side EE continue to be a major

[15] *http://www.eda.gov/power/.*

[16] *https://www.whitehouse.gov/the-press-office/2015/03/27/fact-sheet-partnerships-opportunity-and-workforce-and-economic-revitaliz.*

compliance option. The CEIP will encourage early investment in these types of projects as well. In addition to carbon reduction benefits, we expect significant near- and long-term public health benefits in communities as conventional air pollutants are reduced along with GHGs. However, some stakeholders expressed concerns about the possibility of localized increases in emissions from some power plants as the utility industry complies with state plans, in particular in communities already disproportionately affected by air pollution. This rule sets expectations for states to engage with vulnerable communities as they develop their plans, so that impacts on these communities are considered as plans are designed. The EPA also encourages states to engage with workers in the utility power and related sectors, as well as their worker representatives, so that impacts on their communities may be considered. The EPA commits, once implementation is under way, to assess the impacts of this rule. Likewise, we encourage states to evaluate the effects of their plans to ensure that there are no disproportionate adverse impacts on their communities.

5. Additional Context for This Final Rule

a. *Climate change impacts.* This final rule is an important step in an essential series of long-term actions that are achieving and must continue to achieve the GHG emission reductions needed to address the serious threat of climate change, and constitutes a major commitment—and international leadership-by-doing—on the part of the U.S., one of the world's largest GHG emitters. GHG pollution threatens the American public by leading to damaging and long-lasting changes in our climate that can have a range of severe negative effects on human health and the environment. CO_2 is the primary GHG pollutant, accounting for nearly three-quarters of global GHG emissions[17] and 82 percent of U.S. GHG emissions.[18] The May 2014 report of the National Climate Assessment[19] concluded that climate change impacts are already manifesting themselves and imposing losses and costs. The report documents increases in extreme weather and climate events in recent decades, with resulting damage and disruption to human well-being, infrastructure, ecosystems, and agriculture, and projects continued increases in impacts across a wide range of communities, sectors, and ecosystems. New scientific assessments since 2009, when the EPA determined that GHGs pose a threat to human health and the environment (the ''Endangerment Finding''), highlight the urgency of addressing the rising concentration of CO_2 in the atmosphere. Certain groups, including children, the elderly, and the poor, are most vulnerable to climate-related effects. Recent studies also find that certain communities, including low-income communities and some communities of color (more specifically, populations defined jointly by ethnic/racial characteristics and geographic location), are disproportionately affected by certain climate change related impacts—including heat waves, degraded air quality, and extreme weather events—which are associated with increased deaths, illnesses, and economic challenges. Studies also find that climate change poses particular threats to the health, well-being, and ways of life of indigenous peoples in the U.S.

b. *The utility power sector.* One of the strategies of the President's Climate Action Plan is to reduce CO_2 emissions from power plants.[20] This is because fossil fuel-fired EGUs are by far the largest emitters of GHGs, primarily in the form of CO_2. Among stationary sources in the U.S. and among fossil fuel-fired EGUs, coal-fired units are by far the largest emitters of GHGs. To accomplish the goal of reducing CO_2 emissions from power plants, President Obama issued a Presidential Memorandum[21] that recognized the importance of significant and prompt action. The Memorandum directed the EPA to complete carbon pollution standards, regulations or guidelines, as appropriate, for new, modified, reconstructed and existing power plants, and in doing so to build on state leadership in moving toward a cleaner power sector. In this action and the concurrent CAA section 111(b) rule, the EPA is finalizing regulations to reduce GHG emissions from fossil fuel-fired EGUs. This CAA section 111(d) action builds on actions states and utilities are already taking to move toward cleaner generation of electric power.

The utility power sector is unlike other industrial sectors. In other sectors, sources effectively operate independently and on a local-site scale, with control of their physical operations resting in the hands of their respective owners and operators. Pollution control standards, which focus on each source in a non-utility industrial source category, have reflected the standalone character of individual source investment decision-making and operations.

In stark contrast, the utility power sector comprises a unique system of electricity resources, including the EGUs affected under these guidelines, that operate in a complex and interconnected grid where electricity generally flows freely (*e.g.,* portions of the system cannot be easily isolated through the use of switches or valves as can be done in other networked systems like trains and pipeline systems). That grid is physically interconnected and operated on an integrated basis across large regions. In this interconnected system, system operators, whose decisions, protocols, and actions, to a significant extent, dictate the operations of individual EGUs and large ensembles of EGUs, must reliably balance supply and demand using available generation and demand-side resources, including EE, demand response and a wide range of low- and zero-emitting sources. These resources are managed to meet the system needs in a reliable and efficient manner. Each aspect of this interconnected system is highly regulated and coordinated, with supply and demand constantly being balanced to meet system needs. Each step of the process from the electric generator to the end user is highly regulated by multiple entities working in coordination and considering overall system reliability. For example, in an independent system operator (ISO) or regional transmission organization (RTO) with a centralized, organized capacity market, electric generators are paid to be available to run when needed, must bid into energy markets, must respond to dispatch instructions, and must have permission to schedule maintenance. The ISO/RTO dispatches resources in a way that maintains electric system reliability.

The approach we take in the final guidelines—both in the way we defined the BSER and established the resulting emission performance rates, and in the ranges of options we created for states

[17] Intergovernmental Panel on Climate Change (IPCC) report, ''Contribution of Working Group I to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change,'' 2007. Available at *http://epa.gov/climatechange/ghgemissions/global.html.*

[18] From Table ES–2 ''Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2013'', Report EPA 430–R–15–004, United States Environmental Protection Agency, April 15, 2015. Available at *http://epa.gov/climatechange/ghgemissions/usinventoryreport.html.*

[19] U.S. Global Change Research Program, Climate Change Impacts in the United States: The Third National Climate Assessment, May 2014. Available at *http://nca2014.globalchange.gov/.*

[20] The President's Climate Action Plan, June 2013. *http://www.whitehouse.gov/sites/default/files/image/president27sclimateactionplan.pdf.*

[21] Presidential Memorandum—Power Sector Carbon Pollution Standards, June 25, 2013. *http://www.whitehouse.gov/the-press-office/2013/06/25/presidential-memorandum-power-sector-carbon-pollution-standards.*

and affected EGUs—is consistent with, and in some ways mirrors, the interconnected, interdependent and highly regulated nature of the utility power sector, the daily operation of affected EGUs within this framework, and the critical role of utilities in providing reliable, affordable electricity at all times and in all places within this complex, regulated system. Thus, not only do these guidelines put a premium on providing as much flexibility and latitude as possible for states and utilities, they also recognize that a given EGU's operations are determined by the availability and use of other generation resources to which it is physically connected and by the collective operating regime that integrates that individual EGU's activity with other resources across the grid.

In this integrated system, numerous entities have both the capability and the responsibility to maintain a reliable electric system. FERC, DOE, state public utility commissions, ISOs, RTOs, other planning authorities, and the North American Electric Reliability Corporation (NERC), all contribute to ensuring the reliability of the electric system in the U.S. Critical to this function are dispatch tools, applied primarily by RTOs, ISOs, and balancing authorities, that operate such that actions taken or costs incurred at one source directly affect or cause actions to occur at other sources. Generation, outages, and transmission changes in one part of the synchronous grid can affect the entire interconnected grid.[22] The interconnection is such that ''[i]f a generator is lost in New York City, its effect is felt in Georgia, Florida, Minneapolis, St. Louis, and New Orleans.'' [23] The U.S. Supreme Court has explicitly recognized the interconnected nature of the electricity grid.[24]

The uniqueness of the utility power sector inevitably affects the way in which environmental regulations are designed. When the EPA promulgates environmental regulations that affect the utility power sector, as we have done numerous times over the past four decades, we do so with the awareness of the importance of the efficient and continuous, uninterrupted operation of the interconnected electricity system in which EGUs participate. We also keep in mind the unique product that this interconnected system provides—electricity services—and the critical role of this sector to the U.S. economy and to the fundamental well-being of all Americans.

In the context of environmental regulation, Congress, the EPA and the states all have recognized—as we do in these final guidelines—that electricity production takes place, at least to some extent, interchangeably between and among multiple generation facilities and different types of generation. This is evidenced in the enactment or promulgation of pollution reduction programs, such as Title IV of the CAA, the NO_X state implementation plan (SIP) Call, the Cross-State Air Pollution Rule (CSAPR), and the Regional Greenhouse Gas Initiative (RGGI). As these actions show, both Congress and the EPA have consistently tailored legislation and regulations affecting the utility power sector to its unique characteristics. For example, in Title IV of the Clean Air Act Amendments of 1990, Congress established a pollution reduction program specifically for fossil fuel-fired EGUs and designed the SO_2 portion of that program with express recognition of the sector's ability to shift generation among various EGUs, which enabled pollution reduction by increasing reliance on natural gas-fired units and RE. Similarly, in the NO_X SIP Call, the Clean Air Interstate Rule (CAIR), and CSAPR, the EPA established pollution reduction programs focused on fossil fuel-fired EGUs and designed those programs with express recognition of the sector's ability to shift generation among various EGUs. In this action, we continue that approach. Both the subcategory-specific emission performance rates, and the pathways offered to achieve them, reflect and are tailored to the unique characteristics of the utility power sector.

The way that power is produced, distributed and used in the U.S. is already changing as a result of advancements in innovative power sector technologies and in the availability and cost of low-carbon fuel, RE and demand-side EE technologies, as well as economic conditions. These changes are taking place at a time when the average age of the coal-fired generating fleet is approaching that at which utilities and states undertake significant new investments to address aging assets. In 2025, the average age of the coal-fired generating fleet is projected to be 49 years old, and 20 percent of those units would be more than 60 years old if they remain in operation at that time. Therefore, even in the absence of additional environmental regulation, states and utilities can be expected to be, and already are, making plans for and investing in the next generation of power production, simply because of the need to take account of the age of current assets and infrastructure. Historically, the industry has invested about $100 billion a year in capital improvements. These guidelines will help ensure that, as those necessary investments are being made, they are integrated with the need to address GHG pollution from the sector.

At the same time, owners/operators of affected EGUs are already pursuing the types of measures contemplated in this rule. Out of 404 entities identified as owners or operators of affected EGUs, representing ownership of 82 percent of the total capacity of the affected EGUs, 178 already own RE generating capacity in addition to fossil fuel-fired generating capacity. In fact, these entities already own aggregate amounts of RE generating capacity equal to 25 percent of the aggregate amounts of their affected EGU capacity.[25] In addition, funding for utility EE programs has been growing rapidly, increasing from $1.6 billion in 2006 to $6.3 billion in 2013.

The final guidelines are based on, and reinforce, the actions already being taken by states and utilities to upgrade aging electricity infrastructure with 21st century technologies. The guidelines will ensure that these trends continue in ways that are consistent with the long-term planning and investment processes already used in the utility power sector. This final rule provides flexibility for states to build upon their progress, and the progress of cities and towns, in addressing GHGs, and minimizes

[22] Casazza, J. and Delea, F., *Understanding Electric Power Systems,* IEEE Press, at 159 (2d ed. 2010).

[23] Casazza, J. and Delea, F., *Understanding Electric Power Systems,* IEEE Press, at 160 (2d ed. 2010).

[24] *Federal Power Comm'n* v. *Florida Power & Light Co.,* 404 U.S. 453, at 460 (1972) (quoting a Federal Power Commission hearing examiner, '' 'If a housewife in Atlanta on the Georgia system turns on a light, every generator on Florida's system almost instantly is caused to produce some quantity of additional electric energy which serves to maintain the balance in the interconnected system between generation and load.' '') (citation omitted). *See also New York* v. *FERC,* 535 U.S. 1, at 7–8 (2002) (stating that ''any electricity that enters the grid immediately becomes a part of a vast pool of energy that is constantly moving in interstate commerce.'') (citation omitted). In *Federal Power Comm'n* v. *Southern California Edison Co.,* 376 U.S. 205 (1964), the Supreme Court found that a sale for resale of electricity from Southern California Edison to the City of Colton, which took place solely in California, was under Federal Power Commission jurisdiction because some of the electricity that Southern California Edison marketed came from out of state. The Supreme Court stated that, '' 'federal jurisdiction was to follow the flow of electric energy, an engineering and scientific, rather than a legalistic or governmental, test.' '' *Id.* at 210, *quoting Connecticut Light & Power Co.* v. *Federal Power Commission,* 324 U.S. 515, 529 (1945) (emphasis omitted).

[25] SNL Energy. Data used with permission. Accessed on June 9, 2015.

additional requirements for existing programs where possible. It also allows states to pursue policies to reduce carbon pollution that: (1) Continue to rely on a diverse set of energy resources; (2) ensure electric system reliability; (3) provide affordable electricity; (4) recognize investments that states and power companies are already making; and (5) tailor plans to meet their respective energy, environmental and economic needs and goals, and those of their local communities. Thus, the final guidelines will achieve meaningful CO_2 emission reductions while maintaining the reliability and affordability of electricity in the U.S.

6. Projected National-Level Emission Reductions

Under the final guidelines, the EPA projects annual CO_2 reductions of 22 to 23 percent below 2005 levels in 2020, 28 to 29 percent below 2005 levels in 2025, and 32 percent below 2005 levels in 2030. These guidelines will also result in important reductions in emissions of criteria air pollutants, including SO_2, NO_X, and directly-emitted fine particulate matter ($PM_{2.5}$). A thorough discussion of the EPA's analysis is presented in Section XI.A of this preamble and in Chapter 3 of the Regulatory Impact Analysis (RIA) included in the docket for this rulemaking.

7. Costs and Benefits

Actions taken to comply with the final guidelines will reduce emissions of CO_2 and other air pollutants, including SO_2, NO_X, and directly emitted $PM_{2.5}$ from the utility power sector. States will make the ultimate determination as to how the emission guidelines are implemented. Thus, all costs and benefits reported for this action are illustrative estimates. The illustrative costs and benefits are based upon compliance approaches that reflect a range of measures consisting of improved operations at EGUs, dispatching lower-emitting EGUs and zero-emitting energy sources, and increasing levels of end-use EE.

Because of the range of choices available to states and the lack of *a priori* knowledge about the specific choices states will make in response to the final goals, the RIA for this final action presents two scenarios designed to achieve these goals, which we term the ''rate-based'' illustrative plan approach and the ''mass-based'' illustrative plan approach.

In summary, we estimate the total combined climate benefits and health co-benefits for the rate-based approach to be $3.5 to $4.6 billion in 2020, $18 to $28 billion in 2025, and $34 to $54 billion in 2030 (3 percent discount rate, 2011$). Total combined climate benefits and health co-benefits for the mass-based approach are estimated to be $5.3 to $8.1 billion in 2020, $19 to $29 billion in 2025, and $32 to $48 billion in 2030 (3 percent discount rate, 2011$). A summary of the emission reductions and monetized benefits estimated for this rule at all discount rates is provided in Tables 15 through 22 of this preamble.

The annual compliance costs are estimated using the Integrated Planning Model (IPM) and include demand-side EE program and participant costs as well as monitoring, reporting and recordkeeping costs. In 2020, total compliance costs of the final guidelines are approximately $2.5 billion (2011$) under the rate-based approach and $1.4 billion (2011$) under the mass-based approach. In 2025, total compliance costs of the final guidelines are approximately $1.0 billion (2011$) under the rate-based approach and $3.0 billion (2011$) under the mass-based approach. In 2030, total compliance costs of the final guidelines are approximately $8.4 billion (2011$) under the rate-based approach and $5.1 billion (2011$) under the mass-based approach.

The quantified net benefits (the difference between monetized benefits and compliance costs) in 2020 are estimated to range from $1.0 billion to $2.1 billion (2011$) using a 3 percent discount rate (model average) under the rate-based approach and from $3.9 billion to $6.7 billion (2011$) using a 3 percent discount rate (model average) under the mass-based approach. In 2025, the quantified net benefits (the difference between monetized benefits and compliance costs) in 2025 are estimated to range from $17 billion to $27 billion (2011$) using a 3 percent discount rate (model average) under the rate-based approach and from $16 billion to $26 billion (2011$) using a 3 percent discount rate (model average) under the mass-based approach. In 2030, the quantified net benefits (the difference between monetized benefits and compliance costs) in 2030 are estimated to range from $26 billion to $45 billion (2011$) using a 3 percent discount rate (model average) under the rate-based approach and from $26 billion to $43 billion (2011$) using a 3 percent discount rate (model average) under the mass-based approach.

TABLE 1—SUMMARY OF THE MONETIZED BENEFITS, COMPLIANCE COSTS, AND NET BENEFITS FOR THE FINAL GUIDELINES IN 2020, 2025, AND 2030 [a] UNDER THE RATE-BASED ILLUSTRATIVE PLAN APPROACH

[Billions of 2011$]

	3% Discount rate	7% Discount rate
Rate-based approach, 2020		
Climate benefits [b]	$2.8	
Air pollution health co-benefits [c]	$0.70 to $1.8	$0.64 to $1.7.
Total Compliance Costs [d]	$2.5	$2.5.
Net Monetized Benefits [e]	$1.0 to $2.1	$1.0 to $2.0.
Non-monetized Benefits	Non-monetized climate benefits. Reductions in exposure to ambient NO_2 and SO_2. Reductions in mercury deposition. Ecosystem benefits associated with reductions in emissions of NO_X, SO_2, PM, and mercury. Visibility impairment.	
Rate-based approach, 2025		
Climate benefits [b]	$10	
Air pollution health co-benefits [c]	$7.4 to $18	$6.7 to $16.
Total Compliance Costs [d]	$1.0	$1.0.
Net Monetized Benefits [e]	$17 to $27	$16 to $25.
Non-monetized Benefits	Non-monetized climate benefits. Reductions in exposure to ambient NO_2 and SO_2. Reductions in mercury deposition. Ecosystem benefits associated with reductions in emissions of NO_X, SO_2, PM, and mercury. Visibility impairment.	
Rate-based approach, 2030		
Climate benefits [b]	$20	
Air pollution health co-benefits [c]	$14 to $34	$13 to $31.
Total Compliance Costs [d]	$8.4	$8.4.
Net Monetized Benefits [e]	$26 to $45	$25 to $43.
Non-monetized Benefits	Non-monetized climate benefits. Reductions in exposure to ambient NO_2 and SO_2. Reductions in mercury deposition. Ecosystem benefits associated with reductions in emissions of NO_X, SO_2, PM, and mercury. Visibility impairment.	

[a] All are rounded to two significant figures, so figures may not sum.

[b] The climate benefit estimate in this summary table reflects global impacts from CO_2 emission changes and does not account for changes in non-CO_2 GHG emissions. Also, different discount rates are applied to SC–CO_2 than to the other estimates because CO_2 emissions are long-lived and subsequent damages occur over many years. The benefit estimates in this table are based on the average SCC estimated for a 3 percent discount rate, however we emphasize the importance and value of considering the full range of SC–CO_2 values. As shown in the RIA, climate benefits are also estimated using the other three SC–CO_2 estimates (model average at 2.5 percent discount rate, 3 percent, and 5 percent; 95th percentile at 3 percent). The SC–CO_2 estimates are year-specific and increase over time.

[c] The air pollution health co-benefits reflect reduced exposure to $PM_{2.5}$ and ozone associated with emission reductions of directly emitted $PM_{2.5}$, SO_2 and NO_X. The range reflects the use of concentration-response functions from different epidemiology studies. The reduction in premature fatalities each year accounts for over 98 percent of total monetized co-benefits from $PM_{2.5}$ and ozone. These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effect estimates by particle type.

[d] Total costs are approximated by the illustrative compliance costs estimated using the Integrated Planning Model for the final guidelines and a discount rate of approximately 5%. This estimate includes monitoring, recordkeeping, and reporting costs and demand-side EE program and participant costs.

[e] The estimates of net benefits in this summary table are calculated using the global SC–CO_2 at a 3 percent discount rate (model average). The RIA includes combined climate and health estimates based on additional discount rates.

TABLE 2—SUMMARY OF THE MONETIZED BENEFITS, COMPLIANCE COSTS, AND NET BENEFITS FOR THE FINAL GUIDELINES IN 2020, 2025 AND 2030[a] UNDER THE MASS-BASED ILLUSTRATIVE PLAN APPROACH

[Billions of 2011$]

Mass-based approach, 2020		
	3% Discount rate	7% Discount rate
Climate benefits[b]	$3.3	
Air pollution health co-benefits[c]	$2.0 to $4.8	$1.8 to $4.4.
Total Compliance Costs[d]	$1.4	$1.4.
Net Monetized Benefits[e]	$3.9 to $6.7	$3.7 to $6.3.
Non-monetized Benefits	Non-monetized climate benefits. Reductions in exposure to ambient NO_2 and SO_2. Reductions in mercury deposition. Ecosystem benefits associated with reductions in emissions of NO_X, SO_2, PM, and mercury. Visibility impairment.	
Mass-based approach, 2025		
Climate benefits[b]	$12	
Air pollution health co-benefits[c]	$7.1 to $17	$6.5 to $16.
Total Compliance Costs[d]	$3.0	$3.0.
Net Monetized Benefits[e]	$16 to $26	$15 to $24.
Non-monetized Benefits	Non-monetized climate benefits. Reductions in exposure to ambient NO_2 and SO_2. Reductions in mercury deposition. Ecosystem benefits associated with reductions in emissions of NO_X, SO_2, PM, and mercury. Visibility impairment.	
Mass-based approach, 2030		
Climate benefits[b]	$20	
Air pollution health co-benefits[c]	$12 to $28	$11 to $26.
Total Compliance Costs[d]	$5.1	$5.1.
Net Monetized Benefits[e]	$26 to $43	$25 to $40.
Non-monetized Benefits	Non-monetized climate benefits. Reductions in exposure to ambient NO_2 and SO_2. Reductions in mercury deposition. Ecosystem benefits associated with reductions in emissions of NO_X, SO_2, PM, and mercury. Visibility impairment.	

[a] All are rounded to two significant figures, so figures may not sum.

[b] The climate benefit estimate in this summary table reflects global impacts from CO_2 emission changes and does not account for changes in non-CO_2 GHG emissions. Also, different discount rates are applied to SC–CO_2 than to the other estimates because CO_2 emissions are long-lived and subsequent damages occur over many years. The benefit estimates in this table are based on the average SC–CO_2 estimated for a 3 percent discount rate, however we emphasize the importance and value of considering the full range of SC–CO_2 values. As shown in the RIA, climate benefits are also estimated using the other three SC–CO_2 estimates (model average at 2.5 percent discount rate, 3 percent, and 5 percent; 95th percentile at 3 percent). The SC–CO_2 estimates are year-specific and increase over time.

[c] The air pollution health co-benefits reflect reduced exposure to $PM_{2.5}$ and ozone associated with emission reductions of directly emitted $PM_{2.5}$, SO_2 and NO_X. The range reflects the use of concentration-response functions from different epidemiology studies. The reduction in premature fatalities each year accounts for over 98 percent of total monetized co-benefits from $PM_{2.5}$ and ozone. These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effect estimates by particle type.

[d] Total costs are approximated by the illustrative compliance costs estimated using the Integrated Planning Model for the final guidelines and a discount rate of approximately 5 percent. This estimate includes monitoring, recordkeeping, and reporting costs and demand-side EE program and participant costs.

[e] The estimates of net benefits in this summary table are calculated using the global SC–CO_2 at a 3 percent discount rate (model average). The RIA includes combined climate and health estimates based on additional discount rates.

There are additional important benefits that the EPA could not monetize. Due to current data and modeling limitations, our estimates of the benefits from reducing CO_2 emissions do not include important impacts like ocean acidification or potential tipping points in natural or managed ecosystems. The unquantified benefits also include climate benefits from reducing emissions of non-CO_2 GHGs (*e.g.,* nitrous oxide and methane) [26] and co-benefits from reducing direct exposure to SO_2, NO_X, and HAP (*e.g.,* mercury and hydrogen chloride), as well as from reducing ecosystem effects and visibility impairment.

We project employment gains and losses relative to base case for different types of labor, including construction, plant operation and maintenance, coal and natural gas production, and demand-side EE. In 2030, we project a net decrease in job-years of about 31,000 under the rate-based approach and 34,000 under the mass-based approach [27] for construction, plant operation and maintenance, and coal and natural gas and a gain of 52,000 to 83,000 jobs in the demand-side EE sector under either approach. Actual employment impacts will depend upon measures taken by states in their state plans and the specific actions sources take to comply.

Based upon the foregoing, it is clear that the monetized benefits of this rule are substantial and far outweigh the costs.

B. Organization and Approach for This Rule

This final rule establishes the EPA's emission guidelines for states to follow in developing plans to reduce CO_2 emissions from the utility power sector. Section II of this preamble provides background information on climate change impacts from GHG emissions, GHG emissions from fossil fuel-fired EGUs, the utility power sector, the CAA section 111(d) requirements, EPA actions prior to this final action, outreach and consultations, and the number and extent of comments received. In section III of the preamble, we present a summary of the rule requirements and the legal basis for these. Section IV explains the EPA authority to regulate CO_2 and EGUs, identifies affected EGUs, and describes the proposed treatment of source categories. Section V describes the agency's determination of the BSER using three building blocks and our key considerations in making the determination. Section VI provides the subcategory-specific emission performance rates, and section VII provides equivalent statewide rate-based and mass-based goals. Section VIII then describes state plan approaches and the requirements, and flexibilities, for state plans, followed by section IX, in which considerations for communities are described. Interactions between this final rule and other EPA programs and rules are discussed in section X. Impacts of the proposed action are then described in section XI, followed by a discussion of statutory and executive order reviews in section XII and the statutory authority for this action in section XIII.

We note that this rulemaking is being promulgated concurrently with two related actions in this issue of the **Federal Register**: The final NSPS for CO_2 emissions from newly constructed, modified, and reconstructed EGUs, which is being promulgated under CAA section 111(b), and the proposed federal plan and model rules. These rulemakings have their own rulemaking dockets.

II. Background

In this section, we discuss climate change impacts from GHG emissions, both on public health and public welfare. We also present information about GHG emissions from fossil fuel-fired EGUs, the challenges associated with controlling carbon dioxide emissions, the uniqueness of the utility power sector, and recent and continuing trends and transitions in the utility power sector. In addition, we briefly describe CAA regulations for power plants, provide highlights of Congressional awareness of climate change and international agreements and actions, and summarize statutory and regulatory requirements relevant to this rulemaking. In addition, we provide background information on the EPA's June 18, 2014 Clean Power Plan proposal, the November 4, 2014 supplemental proposal, and other actions associated with this rulemaking,[28] followed by information on stakeholder outreach and consultations and the comments that the EPA received prior to issuing this final rulemaking.

A. Climate Change Impacts From GHG Emissions

According to the National Research Council, ''Emissions of CO_2 from the burning of fossil fuels have ushered in a new epoch where human activities will largely determine the evolution of Earth's climate. Because CO_2 in the atmosphere is long lived, it can effectively lock Earth and future generations into a range of impacts, some of which could become very severe. Therefore, emission reduction choices made today matter in determining impacts experienced not just over the next few decades, but in the coming centuries and millennia.'' [29]

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).[30] 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 U.S. We summarize these adverse effects on public health and welfare briefly here.

1. 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 U.S. 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

[26] Although CO_2 is the predominant greenhouse gas released by the power sector, electricity generating units also emit small amounts of nitrous oxide and methane. For more detail about power sector emissions, see RIA Chapter 2 and the U.S. Greenhouse Gas Reporting Program's power sector summary, *http://www.epa.gov/ghgreporting/ghgdata/reported/powerplants.html*.

[27] A job-year is not an individual job; rather, a job-year is the amount of work performed by the equivalent of one full-time individual for one year. For example, 20 job-years in 2025 may represent 20 full-time jobs or 40 half-time jobs.

[28] The EPA also published in the **Federal Register** a notice of data availability (79 FR 64543; November 8, 2014) and a notice on the translation of emission rate-based CO_2 goals to mass-based equivalents (79 FR 67406; November 13, 2014).

[29] National Research Council, Climate Stabilization Targets, p.3.

[30] ''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'').

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.

2. 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.

3. 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 (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), the 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, the IPCC, and the NRC of the National Academies 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 U.S. 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 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 U.S. 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.'' [31] 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

[31] 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. *https://www.ipcc.ch/report/ar5/wg2/.*

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.[32] 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.'' [33] Because of these unprecedented changes, several assessments state that we may be approaching critical, poorly understood thresholds. As stated in the assessment, ''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 any given concentration of CO_2 reached 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 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 was 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,'' [34] 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

[32] National Research Council, Understanding Earth's Deep Past, p. 1.

[33] Id., p.138.

[34] NRC, 2011: *National Security Implications of Climate Change for U.S. Naval Forces.* The National Academies Press, p. 28.

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.'' [35] 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 CO_2 levels could be sufficient to exceed that threshold.

In general, climate change impacts are expected to be unevenly distributed across different regions of the U.S. 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 U.S. 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.'' [36] 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.'' [37]

Carbon dioxide in particular has unique impacts on ocean ecosystems. The NRC Climate Stabilization Targets assessment found that coral bleaching will increase due both to warming and ocean acidification. Ocean surface waters have already become 30 percent more acidic over the past 250 years due to absorption of CO_2 from the atmosphere. According to the NCA3, this acidification will reduce the ability of organisms such as corals, krill, oysters, clams, and crabs to survive, grow, and reproduce. The NRC Understanding Earth's Deep Past assessment notes four of the five major coral reef crises of the past 500 million years were caused by acidification and warming that followed GHG increases of similar magnitude to the emissions increases expected over the next hundred years. The NRC Abrupt Impacts assessment specifically highlighted similarities between the projections for future acidification and warming and the extinction at the end of the Permian which resulted in the loss of an estimated 90 percent of known species. Similarly, the NRC Ocean Acidification assessment finds that ''[t]he chemistry of the ocean is changing at an unprecedented rate and magnitude due to anthropogenic carbon dioxide emissions; the rate of change exceeds any known to have occurred for at least the past hundreds of thousands of years.'' [38] The assessment notes that the full range of consequences is still unknown, but the risks ''threaten coral reefs, fisheries, protected species, and other natural resources of value to society.'' [39]

Events outside the U.S., 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 U.S. 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 percent probability) that human influence was the dominant cause of the observed warming since the mid-20th century, and likely (>66 percent 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 context, 360 gigatons of ice melt is sufficient to cause global sea levels to rise 1 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

[35] 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.

[36] 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.

[37] 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. *https://www.ipcc.ch/report/ar5/wg2/.*

[38] NRC, 2010: *Ocean Acidification: A National Strategy to Meet the Challenges of a Changing Ocean.* The National Academies Press, p. 5.

[39] Ibid.

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. In 2009, the year of the Endangerment Finding, the average concentration of CO_2 as measured on top of Mauna Loa was 387 parts per million, far above preindustrial concentrations of about 280 parts per million.[40] The average concentration in 2013, the last full year before this rule was proposed, was 396 parts per million. The average concentration in 2014 was 399 parts per million. And the monthly concentration in April of 2014 was 401 parts per million, the first time a monthly average has exceeded 400 parts per million since record keeping began at Mauna Loa in 1958, and for at least the past 800,000 years.[41] 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.[42] 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.[43] 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." [44] 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.

4. Observed and Projected U.S. Regional Changes

The NCA3 assessed the climate impacts in 8 regions of the U.S., noting that changes in physical climate parameters such as temperatures, precipitation, and sea ice retreat were already having impacts on forests, water supplies, ecosystems, flooding, heat waves, and air quality. Moreover, the NCA3 found that future warming is projected to be much larger than recent observed variations in temperature, with precipitation likely to increase in the northern states, decrease in the southern states, and with the heaviest precipitation events projected to increase everywhere.

In the Northeast, temperatures increased almost 2 °F from 1895 to 2011, precipitation increased by about 5 inches (10 percent), and sea level rise of about a foot has led to an increase in coastal flooding. The 70 percent increase in the amount of rainfall falling in the 1 percent of the most intense events is a larger increase in extreme precipitation than experienced in any other U.S. region.

In the future, if emissions continue increasing, the Northeast is expected to experience 4.5 to 10 °F of warming by the 2080s. This will lead to more heat waves, coastal and river flooding, and intense precipitation events. The southern portion of the region is projected to see 60 additional days per year above 90 °F by mid-century. Sea levels in the Northeast are expected to increase faster than the global average because of subsidence, and changing ocean currents may further increase the rate of sea level rise. Specific vulnerabilities highlighted by the NCA include large urban populations particularly vulnerable to climate-related heat waves and poor air quality episodes, prevalence of climate sensitive vector-borne diseases like Lyme and West Nile Virus, usage of combined sewer systems that may lead to untreated water being released into local water bodies after climate-related heavy precipitation events, and 1.6 million people living within the 100-year coastal flood zone who are expected to experience more frequent floods due to sea level rise and tropical-storm induced storm-surge. The NCA also highlighted infrastructure vulnerable to inundation in coastal metropolitan areas, potential agricultural impacts from increased rain in the spring delaying planting or damaging crops or increased heat in the summer leading to decreased yields and increased water demand, and shifts in ecosystems leading to declines in iconic species in some regions, such as cod and lobster south of Cape Cod.

In the Southeast, average annual temperature during the last century cycled between warm and cool periods. A warm peak occurred during the 1930s and 1940s followed by a cool period and temperatures then increased again from 1970 to the present by an average of 2 °F. There have been increasing numbers of days above 95 °F and nights above 75 °F, and decreasing numbers of extremely cold days since 1970. Daily and five-day rainfall intensities have also increased, and summers have been either increasingly dry or extremely wet. Louisiana has already lost 1,880 square miles of land in the last 80 years due to sea level rise and other contributing factors.

The Southeast is exceptionally vulnerable to sea level rise, extreme heat events, hurricanes, and decreased water availability. Major consequences of further warming include significant increases in the number of hot days (95 °F or above) and decreases in freezing events, as well as exacerbated ground-level ozone in urban areas. Although projected warming for some parts of the region by the year 2100 are generally smaller than for other regions of the U.S., projected warming for interior states of the region are larger than coastal regions by 1 °F to 2 °F. Projections further suggest that globally there will be fewer tropical storms, but that they will be more intense, with more Category 4 and 5 storms. The NCA identified New Orleans, Miami, Tampa, Charleston, and Virginia Beach as being specific cities that are at risk due to sea level rise, with homes and infrastructure increasingly prone to flooding. Additional impacts of sea level rise are expected for coastal highways, wetlands, fresh water supplies, and energy infrastructure.

In the Northwest, temperatures increased by about 1.3 °F between 1895 and 2011. A small average increase in precipitation was observed over this time period. However, warming temperatures have caused increased rainfall relative to snowfall, which has

[40] *ftp://aftp.cmdl.noaa.gov/products/trends/co2/co2_annmean_mlo.txt.*

[41] *http://www.esrl.noaa.gov/gmd/ccgg/trends/.*

[42] Blunden, J., and D. S. Arndt, Eds., 2014: State of the Climate in 2013. Bull. Amer. Meteor. Soc., 95 (7), S1–S238.

[43] *http://www.ncdc.noaa.gov/sotc/global/2014/13.*

[44] NRC, 2011: *America's Climate Choices,* The National Academies Press.

altered water availability from snowpack across parts of the region. Snowpack in the Northwest is an important freshwater source for the region. More precipitation falling as rain instead of snow has reduced the snowpack, and warmer springs have corresponded to earlier snowpack melting and reduced streamflows during summer months. Drier conditions have increased the extent of wildfires in the region.

Average annual temperatures are projected to increase by 3.3 °F to 9.7 °F by the end of the century (depending on future global GHG emissions), with the greatest warming expected during the summer. Continued increases in global GHG emissions are projected to result in up to a 30 percent decrease in summer precipitation. Earlier snowpack melt and lower summer stream flows are expected by the end of the century and will affect drinking water supplies, agriculture, ecosystems, and hydropower production. Warmer waters are expected to increase disease and mortality in important fish species, including Chinook and sockeye salmon. Ocean acidification also threatens species such as oysters, with the Northwest coastal waters already being some of the most acidified worldwide due to coastal upwelling and other local factors. Forest pests are expected to spread and wildfires burn larger areas. Other high-elevation ecosystems are projected to be lost because they can no longer survive the climatic conditions. Low lying coastal areas, including the cities of Seattle and Olympia, will experience heightened risks of sea level rise, erosion, seawater inundation and damage to infrastructure and coastal ecosystems.

In Alaska, temperatures have changed faster than anywhere else in the U.S. Annual temperatures increased by about 3 °F in the past 60 years. Warming in the winter has been even greater, rising by an average of 6 °F. Arctic sea ice is thinning and shrinking in area, with the summer minimum ice extent now covering only half the area it did when satellite records began in 1979. Glaciers in Alaska are melting at some of the fastest rates on Earth. Permafrost soils are also warming and beginning to thaw. Drier conditions have contributed to more large wildfires in the last 10 years than in any previous decade since the 1940s, when recordkeeping began. Climate change impacts are harming the health, safety and livelihoods of Native Alaskan communities.

By the end of this century, continued increases in GHG emissions are expected to increase temperatures by 10 to 12 °F in the northernmost parts of Alaska, by 8 to 10 °F in the interior, and by 6 to 8 °F across the rest of the state. These increases will exacerbate ongoing arctic sea ice loss, glacial melt, permafrost thaw and increased wildfire, and threaten humans, ecosystems, and infrastructure. Precipitation is expected to increase to varying degrees across the state, however warmer air temperatures and a longer growing season are expected to result in drier conditions. Native Alaskans are expected to experience declines in economically, nutritionally, and culturally important wildlife and plant species. Health threats will also increase, including loss of clean water, saltwater intrusion, sewage contamination from thawing permafrost, and northward extension of diseases. Wildfires will increasingly pose threats to human health as a result of smoke and direct contact. Areas underlain by ice-rich permafrost across the state are likely to experience ground subsidence and extensive damage to infrastructure as the permafrost thaws. Important ecosystems will continue to be affected. Surface waters and wetlands that are drying provide breeding habitat for millions of waterfowl and shorebirds that winter in the lower 48 states. Warmer ocean temperatures, acidification, and declining sea ice will contribute to changes in the location and availability of commercially and culturally important marine fish.

In the Southwest, temperatures are now about 2 °F higher than the past century, and are already the warmest that region has experienced in at least 600 years. The NCA notes that there is evidence that climate-change induced warming on top of recent drought has influenced tree mortality, wildfire frequency and area, and forest insect outbreaks. Sea levels have risen about 7 or 8 inches in this region, contributing to inundation of Highway 101 and backup of seawater into sewage systems in the San Francisco area.

Projections indicate that the Southwest will warm an additional 5.5 to 9.5 °F over the next century if emissions continue to increase. Winter snowpack in the Southwest is projected to decline (consistent with the record lows from this past winter), reducing the reliability of surface water supplies for cities, agriculture, cooling for power plants, and ecosystems. Sea level rise along the California coast will worsen coastal erosion, increase flooding risk for coastal highways, bridges, and low-lying airports, pose a threat to groundwater supplies in coastal cities such as Los Angeles, and increase vulnerability to floods for hundreds of thousands of residents in coastal areas. Climate change will also have impacts on the high-value specialty crops grown in the region as a drier climate will increase demands for irrigation, more frequent heat waves will reduce yields, and decreased winter chills may impair fruit and nut production for trees in California. Increased drought, higher temperatures, and bark beetle outbreaks are likely to contribute to continued increases in wildfires. The highly urbanized population of the Southwest is vulnerable to heat waves and water supply disruptions, which can be exacerbated in cases where high use of air conditioning triggers energy system failures.

The rate of warming in the Midwest has markedly accelerated over the past few decades. Temperatures rose by more than 1.5 °F from 1900 to 2010, but between 1980 and 2010 the rate of warming was three times faster than from 1900 through 2010.

Precipitation generally increased over the last century, with much of the increase driven by intensification of the heaviest rainfalls. Several types of extreme weather events in the Midwest (*e.g.,* heat waves and flooding) have already increased in frequency and/or intensity due to climate change.

In the future, if emissions continue increasing, the Midwest is expected to experience 5.6 to 8.5 °F of warming by the 2080s, leading to more heat waves. Though projections of changes in total precipitation vary across the regions, more precipitation is expected to fall in the form of heavy downpours across the entire region, leading to an increase in flooding. Specific vulnerabilities highlighted by the NCA include long-term decreases in agricultural productivity, changes in the composition of the region's forests, increased public health threats from heat waves and degraded air and water quality, negative impacts on transportation and other infrastructure associated with extreme rainfall events and flooding, and risks to the Great Lakes including shifts in invasive species, increases in harmful algal blooms, and declining beach health.

High temperatures (more than 100 °F in the Southern Plains and more than 95 °F in the Northern Plains) are projected to occur much more frequently by mid-century. Increases in extreme heat will increase heat stress for residents, energy demand for air conditioning, and water losses. North Dakota's increase in annual temperatures over the past 130 years is the fastest in the contiguous U.S., mainly driven by warming winters. Specific vulnerabilities highlighted by the NCA include increased demand for water and energy, changes to crop growth cycles and agricultural practices, and negative impacts on local plant and animal species from habitat fragmentation, wildfires, and changes in the timing of flowering or pest patterns. Communities that are already the most vulnerable to weather and climate extremes will be stressed even further by more frequent extreme events occurring within an already highly variable climate system.

In Hawaii, other Pacific islands, and the Caribbean, rising air and ocean temperatures, shifting rainfall patterns, changing frequencies and intensities of storms and drought, decreasing baseflow in streams, rising sea levels, and changing ocean chemistry will affect ecosystems on land and in the oceans, as well as local communities, livelihoods, and cultures. Low islands are particularly at risk.

Rising sea levels, coupled with high water levels caused by tropical and extra-tropical storms, will incrementally increase coastal flooding and erosion, damaging coastal ecosystems, infrastructure, and agriculture, and negatively affecting tourism. Ocean temperatures in the Pacific region exhibit strong year-to-year and decadal fluctuations, but since the 1950s, they have exhibited a warming trend, with temperatures from the surface to a depth of 660 feet rising by as much as 3.6 °F. As a result of current sea level rise, the coastline of Puerto Rico around Rincón is being eroded at a rate of 3.3 feet per year. Freshwater supplies are already constrained and will become more limited on many islands. Saltwater intrusion associated with sea level rise will reduce the quantity and quality of freshwater in coastal aquifers, especially on low islands. In areas where precipitation does not increase, freshwater supplies will be adversely affected as air temperature rises.

Warmer oceans are leading to increased coral bleaching events and disease outbreaks in coral reefs, as well as changed distribution patterns of tuna fisheries. Ocean acidification will reduce coral growth and health. Warming and acidification, combined with existing stresses, will strongly affect coral reef fish communities. For Hawaii and the Pacific islands, future sea surface temperatures are projected to increase 2.3 °F by 2055 and 4.7 °F by 2090 under a scenario that assumes continued increases in emissions. Ocean acidification is also taking place in the region, which adds to ecosystem stress from increasing temperatures. Ocean acidity has increased by about 30 percent since the pre-industrial era and is projected to further increase by 37 percent to 50 percent from present levels by 2100.

The NCA also discussed impacts that occur along the coasts and in the oceans adjacent to many regions, and noted that other impacts occur across regions and landscapes in ways that do not follow political boundaries.

B. GHG Emissions From Fossil Fuel-Fired EGUs[45]

Fossil fuel-fired electric utility generating units (EGUs) are by far the largest emitters of GHGs among stationary sources in the U.S., primarily in the form of CO_2, and among fossil fuel-fired EGUs, coal-fired units are by far the largest emitters. This section describes the amounts of these emissions and places these amounts in the context of the U.S. Inventory of Greenhouse Gas Emissions and Sinks[46] (the U.S. GHG Inventory).

The EPA implements a separate program under 40 CFR part 98 called the Greenhouse Gas Reporting Program[47] (GHGRP) that requires emitting facilities over threshold amounts of GHGs to report their emissions to the EPA annually. Using data from the GHGRP, this section also places emissions from fossil fuel-fired EGUs in the context of the total emissions reported to the GHGRP from facilities in the other largest-emitting industries.

The EPA prepares the official U.S. GHG Inventory to comply with commitments under the United Nations Framework Convention on Climate Change (UNFCCC). This inventory, which includes recent trends, is organized by industrial sectors. It provides the information in Table 3 below, which presents total U.S. anthropogenic emissions and sinks[48] of GHGs, including CO_2 emissions, for the years 1990, 2005 and 2013.

TABLE 3—U.S. GHG EMISSIONS AND SINKS BY SECTOR

[Million metric tons carbon dioxide equivalent (MMT CO_2 Eq.)][49]

Sector	1990	2005	2013
Energy[50]	5,290.5	6,273.6	5,636.6
Industrial Processes and Product Use	342.1	367.4	359.1
Agriculture	448.7	494.5	515.7
Land Use, Land-Use Change and Forestry	13.8	25.5	23.3
Waste	206.0	189.2	138.3
Total Emissions	6,301.1	7,350.2	6,673.0
Land Use, Land-Use Change and Forestry (Sinks)	(775.8)	(911.9)	(881.7)
Net Emissions (Sources and Sinks)	5,525.2	6,438.3	5,791.2

Total fossil energy-related CO_2 emissions (including both stationary and mobile sources) are the largest contributor to total U.S. GHG emissions, representing 77.3 percent of total 2013 GHG emissions.[51] In 2013, fossil fuel

[45] The emission data presented in this section of the preamble (Section II.B) are in metric tons, in keeping with reporting requirements for the GHGRP and the U.S. GHG Inventory. Note that the mass-based state goals presented in section VII of this preamble, and discussed elsewhere in this preamble, are presented in short tons.

[46] ''Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990—2013'', Report EPA 430–R–15–004, United States Environmental Protection Agency, April 15, 2015. *http://epa.gov/climatechange/ghgemissions/usinventoryreport.html.*

[47] U.S. EPA Greenhouse Gas Reporting Program Dataset, see *http://www.epa.gov/ghgreporting/ghgdata/reportingdatasets.html.*

[48] Sinks are a physical unit or process that stores GHGs, such as forests or underground or deep sea reservoirs of carbon dioxide.

[49] From Table ES–4 of ''Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2013'', Report EPA 430–R–15–004, U.S. Environmental Protection Agency, April 15, 2015. *http://epa.gov/climatechange/ghgemissions/usinventoryreport.html.*

[50] The energy sector includes all greenhouse gases resulting from stationary and mobile energy activities, including fuel combustion and fugitive fuel emissions.

[51] From Table ES–2 ''Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2013'',

combustion by the utility power sector—entities that burn fossil fuel and whose primary business is the generation of electricity—accounted for 38.3 percent of all energy-related CO_2 emissions.[52] Table 4 below presents total CO_2 emissions from fossil fuel-fired EGUs, for years 1990, 2005 and 2013.

TABLE 4—U.S. GHG EMISSIONS FROM GENERATION OF ELECTRICITY FROM COMBUSTION OF FOSSIL FUELS

[MMT CO_2][53]

GHG emissions	1990	2005	2013
Total CO_2 from fossil fuel-fired EGUs	1,820.8	2,400.9	2,039.8
—from coal	1,547.6	1,983.8	1,575.0
—from natural gas	175.3	318.8	441.9
—from petroleum	97.5	97.9	22.4

In addition to preparing the official U.S. GHG Inventory to present comprehensive total U.S. GHG emissions and comply with commitments under the UNFCCC, the EPA collects detailed GHG emissions data from the largest emitting facilities in the U.S. through its Greenhouse Gas Reporting Program (GHGRP). Data collected by the GHGRP from large stationary sources in the industrial sector show that the utility power sector emits far greater CO_2 emissions than any other industrial sector. Table 5 below presents total GHG emissions in 2013 for the largest emitting industrial sectors as reported to the GHGRP. As shown in Table 4 and Table 5, respectively, CO_2 emissions from fossil fuel-fired EGUs are nearly three times as large as the total reported GHG emissions from the next ten largest emitting industrial sectors in the GHGRP database combined.

TABLE 5—DIRECT GHG EMISSIONS REPORTED TO GHGRP BY LARGEST EMITTING INDUSTRIAL SECTORS

[MMT CO_2e][54]

Industrial sector	2013
Petroleum Refineries	176.7
Onshore Oil & Gas Production	94.8
Municipal Solid Waste Landfills	93.0
Iron & Steel Production	84.2
Cement Production	62.8
Natural Gas Processing Plants	59.0
Petrochemical Production	52.7
Hydrogen Production	41.9
Underground Coal Mines	39.8
Food Processing Facilities	30.8

C. Challenges in Controlling Carbon Dioxide Emissions

Carbon dioxide is a unique air pollutant and controlling it presents unique challenges. CO_2 is emitted in enormous quantities, and those quantities, coupled with the fact that CO_2 is relatively unreactive, make it much more difficult to mitigate by measures or technologies that are typically utilized within an existing power plant. Measures that may be used to limit CO_2 emissions would include efficiency improvements, which have thermodynamic limitations and carbon capture and sequestration (CCS), which is energy resource intensive.

Unlike other air pollutants which are results of trace impurities in the fuel, products of incomplete or inefficient combustion, or combustion byproducts, CO_2 is an inherent product of clean, efficient combustion of fossil fuels, and therefore is an unavoidable product generated in enormous quantities, far greater than any other air pollutant.[55] In fact, CO_2 is emitted in far greater quantities than all other air pollutants *combined.* Total emissions of all non-GHG air pollutants in the U.S., from all sources, in 2013, were 121 million metric tons.[56] [57]

Pollutant	2013 tons (million short tons)	Reference
CO	69.758	Trends file (*http://www.epa.gov/ttnchie1/trends/*).
NO_X	13.072	″
PM_{10}	20.651	″
SO_2	5.098	″
VOC	17.471	″
NH_3	4.221	″
HAPS	3.641	2011 NEI version 2 (*http://www.epa.gov/ttn/chief/net/2011inventory.html*).
Total	133.912	

Report EPA 430–R–15–004, United States Environmental Protection Agency, April 15, 2015. *http://epa.gov/climatechange/ghgemissions/usinventoryreport.html.*

[52] From Table 3–1 ''Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2013'', Report EPA 430–R–15–004, United States Environmental Protection Agency, April 15, 2015. *http://epa.gov/climatechange/ghgemissions/usinventoryreport.html.*

[53] From Table 3–5 ''Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2013'', Report EPA 430–R–15–004, United States Environmental Protection Agency, April 15 2015. *http://epa.gov/climatechange/ghgemissions/usinventory report.html.*

[54] U.S. EPA Greenhouse Gas Reporting Program Dataset as of August 18, 2014. *http://ghgdata.epa.gov/ghgp/main.do.*

[55] Lackner et al., ''Comparative Impacts of Fossil Fuels and Alternative Energy Sources'', Issues in Environmental Science and Technology (2010).

[56] This includes NAAQS and HAPs, based on the following table: (see table above).

It should be noted that $PM_{2.5}$ is included in the amounts for PM_{10}. Lead, another NAAQS pollutant, is emitted in the amounts of approximately 1,000 tons per year, and, in light of that relatively small quantity, was excluded from this analysis. Ammonia (NH_3) is included because it is a precursor to $PM_{2.5}$ secondary formation. Note that one short ton is equivalent to 0.907185 metric ton.

[57] In addition, emissions of non-CO_2 GHGs totaled 1.168 billion metric tons of carbon-dioxide equivalents (CO_2e) in 2013. See Table ES–2, Executive Summary, 1990–2013 Inventory of U.S. Greenhouse Gas Emissions and Sinks. *http://www.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2015-Chapter-Executive-Summary.pdf.* This includes emissions of methane, nitrous oxide, and fluorinated GHGs (hydrofluorocarbons, perfluorocarbons, sulfur hexafluoride, and nitrogen trifluoride). In the total, the emissions of each non-CO_2 GHG have been translated from metric tons of that gas into metric tons of CO_2e by multiplying the metric tons of the gas by the global warming potential (GWP) of the gas. (The GWP of a gas is a measure of the ability of one kilogram of that gas to trap heat in earth's atmosphere compared to one kilogram of CO_2.)

As noted above, total emissions of CO_2 from coal-fired power plants alone—the largest stationary source emitter—were 1.575 billion metric tons in that year,[58] and total emissions of CO_2 from all sources were 5.5 billion metric tons.[59 60] Carbon makes up the majority of the mass of coal and other fossil fuels, and for every ton of carbon burned, more than 3 tons of CO_2 is produced.[61] In addition, unlike many of the other air pollutants that react with sunlight or chemicals in the atmosphere, or are rained out or deposited on surfaces, CO_2 is relatively unreactive and difficult to remove directly from the atmosphere.[62 63]

CO_2's huge quantities and lack of reactivity make it challenging to remove from the smokestack. Retrofitted equipment is required to capture the CO_2 before transporting it to a storage site. However, the scale of infrastructure required to directly mitigate CO_2 emissions from existing EGUs through CCS can be quite large and difficult to integrate into the existing fossil fuel infrastructure. These CCS techniques are discussed in more depth elsewhere in the preamble for this rule and for the section 111(b) rule for new sources that accompanies this rule.

The properties of CO_2 can be contrasted with those of a number of other pollutants which have more accessible mitigation options. For example, the NAAQS pollutants—which generally are emitted in the largest quantities of any of the other air pollutants, except for CO_2—each have more accessible mitigation options. Sulfur dioxide (SO_2) is the result of a contaminant in the fuel, and, as a result, it can be reduced by using low-sulfur coal or by using flue-gas desulfurization (FGD) technologies. Emissions of NO_X can be mitigated relatively easily using combustion control techniques (*e.g.,* low-NO_X burners) and by using downstream controls such as selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR) technologies. PM can be effectively mitigated using fabric filters, PM scrubbers, or electrostatic precipitators. Lead is part of particulate matter emissions and is controlled through the same devices. Carbon monoxide and VOCs are the products of incomplete combustion and can therefore be abated by more efficient combustion conditions, and can also be destroyed in the smokestack by the use of oxidation catalysts which complete the combustion process. Many air toxics are VOCs, such as polyaromatic hydrocarbons, and therefore can be abated in the same ways just described. But in every case, these pollutants can be controlled at the source much more readily than CO_2 primarily because of the comparatively lower quantities that are produced, and also due to other attributes such as relatively greater reactivity and solubility.

D. The Utility Power Sector

1. A Brief History

The modern American electricity system is one of the greatest engineering achievements of the past 100 years. Since the invention of the incandescent light bulb in the 1870s,[64] electricity has become one of the major foundations for modern American life. Beginning with the first power station in New York City in 1882, each power station initially served a discrete set of consumers, resulting in small and localized electricity systems.[65] During the early 1900s, smaller systems consolidated, allowing generation resources to be shared over larger areas. Interconnecting systems have reduced generation investment costs and improved reliability.[66] Local and state governments initially regulated these growing electricity systems with federal regulation coming later in response to public concerns about rising electricity costs.[67]

Initially, states had broad authority to regulate public utilities, but gradually federal regulation increased. In 1920, Congress passed the Federal Water Power Act, creating the Federal Power Commission (FPC) and providing for the licensing of hydroelectric facilities on U.S. government lands and navigable waters of the U.S.[68] During this time period, the U.S. Supreme Court found that state authority to regulate public utilities is limited, holding that the Commerce Clause does not allow state regulation to directly burden interstate commerce.[69] For example, in *Public Utilities Commission of Rhode Island* v. *Attleboro Steam & Electric Company,* Rhode Island sought to regulate the electricity rates that a Rhode Island generator was charging to a company in Massachusetts that resold the electricity to Attleboro, Massachusetts.[70] The Supreme Court found that Rhode Island's regulation was impermissible because it imposed a ''direct burden upon interstate commerce.'' [71] The Supreme Court held that this kind of interstate transaction was not subject to state regulation. However, because Congress had not yet passed legislation to make these types of transactions subject to federal regulation, this became known as the ''*Attleboro* gap'' in regulation. In 1935, Congress passed the Federal Power Act (FPA), giving the FPC jurisdiction over ''the transmission of electric energy in interstate commerce'' and ''the sale of electric energy at wholesale in interstate commerce.'' [72] Under FPA section 205, the FPC was tasked with ensuring that rates for jurisdictional services are just, reasonable, and not unduly discriminatory or preferential.[73] FPA section 206 authorized the FPC to determine, after a hearing upon its own motion or in response to a complaint

[58] From Table 3–5 ''Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2013'', Report EPA 430–R–15–004, United States Environmental Protection Agency, April 15, 2015. *http://epa.gov/climatechange/ghgemissions/usinventoryreport.html.*

[59] U.S. EPA, *Greenhouse Gas Inventory Data Explorer, http://www.epa.gov/climatechange/ghgemissions/inventoryexplorer/#allsectors/allgas/gas/current.*

[60] As another point of comparison, except for carbon dioxide, SO_2 and NO_X are the largest air pollutant emissions from coal-fired power plants. Over the past decade, U.S. power plants have emitted more than 200 times as much CO_2 as they have emitted SO_2 and NO_X. *See* de Gouw et al., ''Reduced emissions of CO_2, NO_X, and SO_2 from U.S. power plants owing to switch from coal to natural gas with combined cycle technology,'' Earth's Future (2014).

[61] Each atom of carbon in the fuel combines with 2 atoms of oxygen in the air.

[62] Seinfeld J. and Pandis S., Atmospheric Chemistry and Physics: From Air Pollution to Climate Change (1998).

[63] The fact that CO_2 is unreactive means that it is primarily removed from the atmosphere by dissolving in oceans or by being converted into biomass by plants. Herzog, H., ''Scaling up carbon dioxide capture and storage: From megatons to gigatons'', Energy Economics (2011).

[64] Regulatory Assistance Project (RAP), *Electricity Regulation in the US: A Guide,* at 1 (2011), *available at http://www.raponline.org/document/download/id/645.*

[65] Casazza, J. and Delea, F., *Understanding Electric Power Systems,* IEEE Press, at 2–4 (2d ed. 2010).

[66] Casazza, J. and Delea, F., *Understanding Electric Power Systems,* IEEE Press, at 5–6 (2d ed. 2010). Investment in electric generation is extremely capital intensive, with generation potentially accounting for 65 percent of customer costs. If these costs can be spread to more customers, then this can reduce the amount that each individual customer pays. Federal Energy Regulatory Commission, *Energy Primer: A Handbook of Energy Market Basics,* at 38 (2012), *available at http://www.ferc.gov/market-oversight/guide/energy-primer.pdf.*

[67] Burn, An Energy Journal, *The Electricity Grid: A History, available at http://burnanenergyjournal.com/the-electric-grid-a-history/* (last visited Mar. 9, 2015).

[68] The FPC became an independent Commission in 1930. *United States Government Manual 1945: First Edition,* at 486, *available at http://www.ibiblio.org/hyperwar/ATO/USGM/FPC.html.*

[69] *New York* v. *Federal Energy Regulatory Commission,* 535 U.S. 1, 5 (2002) (citation omitted).

[70] *Public Utils. Comm'n of Rhode Island* v. *Attleboro Steam & Elec. Co., 273 U.S. 83 (1927).*

[71] *Public Utils. Comm'n of Rhode Island* v. *Attleboro Steam & Elec. Co., 273 U.S. 83, 89 (1927).*

[72] 16 U.S.C. 824(b)(1).

[73] 16 U.S.C. 824d.

filed at the Commission, whether jurisdictional rates are just, reasonable, and not unduly discriminatory or preferential.[74] In 1938, Congress passed the Natural Gas Act (NGA), giving the FPC jurisdiction over the transmission or sale of natural gas in interstate commerce.[75] The NGA also gave the FPC the jurisdiction to ''grant certificates allowing construction and operation of facilities used in interstate gas transmission and authorizing the provision of services.'' [76] In 1977, the FPC became FERC after Congress passed the Department of Energy Organization Act.

By the 1930s, regulated electric utilities that provided the major components of the electrical system—generation, transmission, and distribution—were common.[77] These regulated monopolies are referred to as vertically-integrated utilities.

As utilities built larger and larger electric generation plants, the cost per unit to generate electricity decreased.[78] However, these larger plants were extremely capital intensive for any one company to fund.[79] Some neighboring utilities solved this issue by agreeing to share electricity reserves when needed.[80] These utilities began building larger transmission lines to deliver power in times when large generators experienced outages.[81] Eventually, some utilities that were in reserve sharing agreements formed electric power pools to balance electric load over a larger area. Participating utilities gave control over scheduling and dispatch of their electric generation units to a system operator.[82] Some power pools evolved into today's RTOs and ISOs.

In the past, electric utilities generally operated as state regulated monopolies, supplying end-use customers with generation, distribution, and transmission service.[83] However, the ability of electric utilities to operate as natural monopolies came with consumer protection safeguards.[84] ''In exchange for a franchised, monopoly service area, utilities accept an obligation to serve—meaning there must be adequate supply to meet customers' needs regardless of the cost.'' [85] Under this obligation to serve, the utility agreed to provide service to any customer located within its service jurisdiction.

On both a federal and state level, competition has entered the electricity sector to varying degrees in the last few decades.[86] In the early 1990s, some states began to consider allowing competition to enter retail electric service.[87] Federal and state efforts to allow competition in the electric utility industry have resulted in independent power producers (IPPs) [88] producing approximately 37 percent of net generation in 2013.[89] Electric utilities in some states remain vertically integrated without retail competition from IPPs. Today, there are over 3,000 public, private, and cooperative utilities in the U.S.[90] These utilities include both investor-owned utilities [91] and consumer-owned utilities.[92]

Over time, the grid slowly evolved into a complex, interconnected transmission system that allows electric generators to produce electricity that is then fed onto transmission lines at high voltages.[93] These larger transmission lines are able to access generation that is located more remotely, with transmission lines crossing many miles, including state borders.[94] Closer to end users, electricity is transformed into a lower voltage that is transported across

[74] 16 U.S.C. 824e.

[75] Energy Information Administration, *Natural Gas Act of 1938, available at http://www.eia.gov/oil_gas/natural_gas/analysis_publications/ngmajorleg/ngact1938.html.*

[76] Energy Information Administration, *Natural Gas Act of 1938, available at http://www.eia.gov/oil_gas/natural_gas/analysis_publications/ngmajorleg/ngact1938.html.*

[77] Burn, An Energy Journal, *The Electricity Grid: A History, available at http://burnanenergyjournal.com/the-electric-grid-a-history/* (last visited Mar. 9, 2015).

[78] Federal Energy Regulatory Commission, *Energy Primer: A Handbook of Energy Market Basics,* at 38 (2012), *available at http://www.ferc.gov/market-oversight/guide/energy-primer.pdf.*

[79] Federal Energy Regulatory Commission, *Energy Primer: A Handbook of Energy Market Basics,* at 38 (2012), *available at http://www.ferc.gov/market-oversight/guide/energy-primer.pdf.*

[80] Federal Energy Regulatory Commission, *Energy Primer: A Handbook of Energy Market Basics,* at 38 (2012), *available at http://www.ferc.gov/market-oversight/guide/energy-primer.pdf.*

[81] Federal Energy Regulatory Commission, *Energy Primer: A Handbook of Energy Market Basics,* at 38 (2012), *available at http://www.ferc.gov/market-oversight/guide/energy-primer.pdf.*

[82] Shively, B, Ferrare, J, *Understanding Today's Electricity Business,* Enerdynamics, at 94 (2012).

[83] Maryland Department of Natural Resources, *Maryland Power Plants and the Environment: A Review of the Impacts of Power Plants and Transmission Lines on Maryland's Natural Resources,* at 2–5 (2006), *available at http://esm.versar.com/pprp/ceir13/toc.htm.*

[84] Pacific Power, *Utility Regulation,* at 1, *available at https://www.pacificpower.net/content/dam/pacific_power/doc/About_Us/Newsroom/Media_Resources/Regulation.PP.08.pdf.*

[85] Pacific Power, *Utility Regulation,* at 1, *available at https://www.pacificpower.net/content/dam/pacific_power/doc/About_Us/Newsroom/Media_Resources/Regulation.PP.08.pdf.*

[86] For example, in 1978, Congress passed the Public Utilities Regulatory Policies Act (PURPA) which allowed non-utility owned power plants to sell electricity. Burn, An Energy Journal, *The Electricity Grid: A History, available at http://burnanenergyjournal.com/the-electric-grid-a-history/* (last visited Mar. 9, 2015). PURPA, the Energy Policy Act of 1992 (EPAct 1992), and the Energy Policy Act of 2005 (EPAct 2005) ''promoted competition by lowering entry barriers and increasing transmission access.'' The Electric Energy Market Competition Task Force, *Report to Congress on Competition in Wholesale and Retail Markets for Electric Energy,* at 2, *available at http://www.ferc.gov/legal/fed-sta/ene-pol-act/epact-final-rpt.pdf* (last visited Mar. 20, 2015).

[87] The Electric Energy Market Competition Task Force, *Report to Congress on Competition in Wholesale and Retail Markets for Electric Energy,* at 2, *available at http://www.ferc.gov/legal/fed-sta/ene-pol-act/epact-final-rpt.pdf* (last visited Mar. 20, 2015).

[88] These entities are also referred to as merchant generators.

[89] Energy Information Administration, *Electric Power Annual, Table 1.1 Total Electric Power Summary Statistics, 2013 and 2012* (2015), *available at http://www.eia.gov/electricity/annual/html/epa_01_01.html.*

[90] Regulatory Assistance Project (RAP), *Electricity Regulation in the US: A Guide,* at 9 (2011), *available at http://www.raponline.org/document/download/id/645.*

[91] Investor-owned utilities are private companies that are financed by a combination of shareholder equity and bondholder debt. Regulatory Assistance Project (RAP), *Electricity Regulation in the US: A Guide,* at 9 (2011), *available at http://www.raponline.org/document/download/id/645.*

[92] Consumer-owned utilities include municipal utilities, public utility districts, cooperatives, and a variety of other entities such as irrigation districts. Regulatory Assistance Project (RAP), *Electricity Regulation in the US: A Guide,* at 9–10 (2011), *available at http://www.raponline.org/document/download/id/645.*

[93] Peter Fox-Penner, *Electric Utility Restructuring: A Guide to the Competitive Era,* Public Utility Reports, Inc., at 5, 34 (1997). ''The extent of the power system's short-run physical interdependence is remarkable, if not entirely unique. No other large, multi-stage industry is required to keep every single producer in a region—whether or not owned by the same company—in immediate synchronization with all other producers.'' *Id.* at 34. ''At an early date, those providing electric power recognized that peak use for one system often occurred at a different time from peak use in other systems. They also recognized that equipment failures occurred at different times in various systems. Analyses showed significant economic benefits from interconnecting systems to provide mutual assistance; the investment required for generating capacity could be reduced and reliability could be improved. This lead [sic] to the development of local, then regional, and subsequently three transmission grids that covered the U.S. and parts of Canada.'' Casazza, J. and Delea, F., *Understanding Electric Power Systems,* IEEE Press, at 5–6 (2d ed. 2010).

[94] Burn, An Energy Journal, *The Electricity Grid: A History, available at http://burnanenergyjournal.com/the-electric-grid-a-history/* (last visited Mar. 9, 2015). Because of the ease and low cost of converting voltages in an alternating current (AC) system from one level to another, the bulk power system is predominantly an AC system rather than a direct current (DC) system. In an AC system, electricity cannot be controlled like a gas or liquid by utilizing a valve in a pipe. Instead, absent the presence of expensive control devices, electricity flows freely along all available paths, according to the laws of physics. U.S.-Canada Power System Outage Task Force, *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations,* at 6 (Apr. 2004), *available at http://www.ferc.gov/industries/electric/indus-act/reliability/blackout/ch1-3.pdf.*

localized transmission lines to homes and businesses.[95] Localized transmission lines make up the distribution system. These three components of the electricity system—generation, transmission, and distribution—are closely related and must work in coordination to deliver electricity from the point of generation to the point of consumption. This interconnectedness is a fundamental aspect of the nation's electricity system, requiring a complicated integration of all components of the system to balance supply and demand and a federal, state, and local regulatory network to oversee the physically interconnected network. Facilities planned and constructed in one segment can impact facilities and operations in other segments and vice versa.

The North American electric grid has developed into a large, interconnected system.[96] Electricity from a diverse set of generation resources such as natural gas, nuclear, coal, and renewables is distributed over high-voltage transmission lines divided across the continental U.S. into three synchronous interconnections—the Eastern Interconnection, Western Interconnection, and the Texas Interconnection.[97] These three synchronous systems each act like a single machine.[98] Diverse resources generate electricity that is transmitted and distributed through a complex system of interconnected components to industrial, business, and residential consumers. Unlike other industries where sources make operational decisions independently, the utility power sector is unique in that electricity system resources operate in a complex, interconnected grid system that is physically interconnected and operated on an integrated basis across large regions. Additionally, a federal, state, and local regulatory network oversees policies and practices that are applied to how the system is designed and operates. In this interconnected system, system operators must ensure that the amount of electricity available is precisely matched with the amount needed in real time. System operators have a number of resources potentially available to meet electricity demand, including electricity generated by electric generation units such as coal, nuclear, renewables, and natural gas, as well as demand-side resources,[99] such as EE [100] and demand response.[101] Generation, outages, and transmission changes in one part of the synchronous grid can affect the entire interconnected grid.[102] The interconnection is such that ''[i]f a generator is lost in New York City, its affect is felt in Georgia, Florida, Minneapolis, St. Louis, and New Orleans.'' [103] The U.S. Supreme Court has similarly recognized the interconnected nature of the electricity grid.[104]

Today, federal, state, and local entities regulate electricity providers.[105] Overlaid on the physical electricity network is a regulatory network that has developed over the last century or more. This regulatory network ''plays a vital role in the functioning of all other networks, sometimes providing specific rules for functioning while at other times providing restraints within which their operation must be conducted.'' [106] This unique regulatory network results in an electricity grid that is both physically interconnected and connected through a network of regulation on the local, state, and federal levels. This regulation seeks to reconcile the fact that electricity is a public good with the fact that facilities providing that electricity are privately owned.[107] While this regulation began on the state and local levels, federal regulation of the electricity system increased over time. With the passage of the EPAct 1992 and the EPAct 2005, the federal government's role in electricity regulation greatly increased.[108] ''The role of the regulator now includes support for the development of open

[95] Peter Fox-Penner, *Electric Utility Restructuring: A Guide to the Competitive Era,* Public Utility Reports, Inc., at 5 (1997).

[96] U.S.-Canada Power System Outage Task Force, *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations,* at 5 (Apr. 2004), *available at http://www.ferc.gov/industries/electric/indus-act/reliability/blackout/ch1-3.pdf*.

[97] Regulatory Assistance Project (RAP), *Electricity Regulation in the US: A Guide,* 2011, at 1, *available at http://www.raponline.org/document/download/id/645*.

[98] Casazza, J. and Delea, F., *Understanding Electric Power Systems,* IEEE Press, at 159 (2d ed. 2010). In an amicus brief to the Supreme Court, a group of electrical engineers, economists, and physicists specializing in electricity explained, ''*Energy* is transmitted, not electrons. Energy transmission is accomplished through the propagation of an electromagnetic wave. The electrons merely oscillate in place, but the *energy*—the *electromagnetic wave*—moves at the speed of light. The energized electrons making the lightbulb in a house glow are not the same electrons that were induced to oscillate in the generator back at the power plant. . . . Energy flowing onto a power network or grid *energizes the entire grid,* and consumers then draw undifferentiated energy from that grid. A networked grid flexes, and electric current flows, in conformity with physical laws, and those laws do not notice, let alone conform to, political boundaries. . . . The path taken by electric energy is the path of least resistance . . . or, more accurately, the *paths* of least resistance. . . . If a generator on the grid increases its output, the current flowing from the generator on all paths on the grid increases. These increases affect the energy flowing *into* each point in the network, which in turn leads to compensating and corresponding changes in the energy flows *out* of each point.'' Brief Amicus Curiae of Electrical Engineers, Energy Economists and Physicists in Support of Respondents at 2, 8–9, 11, New York v. FERC, 535 U.S. 1 (2001) (No. 00–568).

[99] ''Measures using demand-side resources comprise actions taken on the customer's side of the meter to change the amount and/or timing of electricity use in ways that will provide benefits to the electricity supply system.'' David Crossley, Regulatory Assistance Project (RAP), *Effective Mechanisms to Increase the Use of Demand-Side Resources,* at 9 (2013), *available at www.raponline.org*.

[100] Energy efficiency is using less energy to provide the same or greater level of service. Demand-side energy efficiency refers to an extensive array of technologies, practices and measures that are applied throughout all sectors of the economy to reduce energy demand while providing the same, and sometimes better, level and quality of service.

[101] Demand response involves ''[c]hanges in electric usage by demand-side resources from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized.'' Federal Energy Regulatory Commission, *Reports on Demand Response & Advanced Metering,* (Dec. 23, 2014), *available at http://www.ferc.gov/industries/electric/indus-act/demand-response/dem-res-adv-metering.asp*.

[102] Casazza, J. and Delea, F., *Understanding Electric Power Systems,* IEEE Press, at 159 (2d ed. 2010).

[103] Casazza, J. and Delea, F., *Understanding Electric Power Systems,* IEEE Press, at 160 (2d ed. 2010).

[104] *Federal Power Comm'n* v. *Florida Power & Light Co.,* 404 U.S. 453, at 460 (1972) (quoting a Federal Power Commission hearing examiner, '''If a housewife in Atlanta on the Georgia system turns on a light, every generator on Florida's system almost instantly is caused to produce some quantity of additional electric energy which serves to maintain the balance in the interconnected system between generation and load.''') (citation omitted). *See also New York* v. *FERC,* 535 U.S. 1, at 7 (2002) (stating that ''any electricity that enters the grid immediately becomes a part of a vast pool of energy that is constantly moving in interstate commerce.'') (citation omitted). In *Federal Power Comm'n* v. *Southern California Edison Co.,* 376 U.S. 205 (1964), the Supreme Court found that a sale for resale of electricity from Southern California Edison to the City of Colton, which took place solely in California, was under Federal Power Commission jurisdiction because some of the electricity that Southern California Edison marketed came from out of state. The Supreme Court stated that, '''federal jurisdiction was to follow the flow of electric energy, an engineering and scientific, rather than a legalistic or governmental, test.''' *Id.* at 210 (quoting *Connecticut Light & Power Co.* v. *Federal Power Commission,* 324 U.S. 515, 529 (1945) (emphasis omitted)).

[105] Casazza, J. and Delea, F., *Understanding Electric Power Systems,* IEEE Press, at 214 (2d ed. 2010).

[106] Casazza, J. and Delea, F., *Understanding Electric Power Systems,* IEEE Press, at 213 (2d ed. 2010).

[107] Casazza, J. and Delea, F., *Understanding Electric Power Systems,* IEEE Press, at 213 (2d ed. 2010).

[108] Casazza, J. and Delea, F., *Understanding Electric Power Systems,* IEEE Press, at 214 (2d ed. 2010).

and fair wholesale electric markets, ensuring equal access to the transmission system and more hands-on oversight and control of the planning and operating rules for the industry.'' [109]

2. Electric System Dispatch

System operators typically dispatch the electric system through a process known as Security Constrained Economic Dispatch.[110] Security Constrained Economic Dispatch has two components—economic generation of generation facilities and ensuring that the electric system remains reliable.[111] Electricity demand varies across geography and time in response to numerous conditions, such that electric generators are constantly responding to changes in the most reliable and cost-effective manner possible. The cost of operating electric generation varies based on a number of factors, such as fuel and generator efficiency.

The decision to dispatch any particular electric generator depends upon the relative operating cost, or marginal cost, of generating electricity to meet the last increment of electric demand. Fuel is one common variable cost—especially for fossil-fueled generators. Coal plants will often have considerable variable costs associated with running pollution controls.[112] Renewables, hydroelectric, and nuclear have little to no variable costs. If electricity demand decreases or additional generation becomes available on the system, this impacts how the system operator will dispatch the system. EGUs using technologies with relatively low variable costs, such as nuclear units and RE, are for economic reasons generally operated at their maximum output whenever they are available. When lower cost units are available to run, higher variable cost units, such as fossil-fuel generators, are generally the first to be displaced.

In states with cost-of-service regulation of vertically-integrated utilities, the utilities themselves form the balancing authorities who determine dispatch based upon the lowest marginal cost. These utilities sometimes arrange to buy and sell electricity with other balancing authorities. RTOs and ISOs coordinate, control, and monitor electricity transmission systems to ensure cost-effective and reliable delivery of power, and they are independent from market participants.

3. Reliability Considerations

The reliability of the electric system has long been a focus of the electric industry and regulators. Industry developed a voluntary organization in the early 1960s that assisted with bulk power system coordination in the U.S. and Canada.[113] In 1965, the northeastern U.S. and southeastern Ontario, Canada experienced the largest power blackout to date, impacting 30 million people.[114] In response to the 1965 blackout and a Federal Power Commission recommendation,[115] industry developed the National Electric Reliability Council (NERC) and nine reliability councils. The organization later became known as the North American Electric Reliability Council to recognize Canada's participation.[116] The North American Electric Reliability Council became the North American Electric Reliability Corporation in 2007.[117]

In August 2003, North America experienced its worst blackout to date creating an outage in the Midwest, Northeast, and Ontario, Canada.[118] This blackout was massive in scale impacting an area with an estimated 50 million people and 61,800 megawatts of electric load.[119] The U.S. and Canada formed a joint task force to investigate the causes of the blackout and made recommendations to avoid similar outages in the future. One of the task force's major recommendations was that the U.S. Congress should pass legislation making electric reliability standards mandatory and enforceable.[120]

Congress responded to this recommendation in EPAct 2005, adding a new section 215 to the Federal Power Act making reliability standards mandatory and enforceable and authorizing the creation of a new Electric Reliability Organization (ERO). Under this new system, FERC certifies an entity as the ERO. The ERO develops reliability standards, which are subject to FERC review and approval. Once FERC approves reliability standards the ERO may enforce those standards or FERC can do so independently.[121] In 2006, the Federal Energy Regulatory Commission (FERC) certified NERC as the ERO.[122] ''NERC develops and enforces Reliability Standards; monitors the Bulk-Power System; assesses adequacy annually via a 10-year forecast and winter and summer forecasts; audits owners, operators and users for preparedness; and educates and trains industry personnel.'' [123]

The U.S., Canada, and part of Mexico are divided up into eight reliability

[109] Casazza, J. and Delea, F., *Understanding Electric Power Systems,* IEEE Press, at 214 (2d ed. 2010).

[110] *Economic Dispatch: Concepts, Practices and Issues,* FERC Staff Presentation to the Joint Board for the Study of Economic Dispatch, Palm Springs, California (Nov. 13, 2005), *available at http://www.ferc.gov/CalendarFiles/20051110172953-FERC%20Staff%20Presentation.pdf.*

[111] Federal Energy Regulatory Commission, *Security Constrained Economic Dispatch: Definitions, Practices, Issues and Recommendations: A Report to Congress* (July 31, 2006). The Energy Policy Act of 2005 defined economic dispatch as ''the operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operational limits of generation and transmission facilities.'' Energy Policy Act of 2005, Pub. L. 109–58, 119 Stat. 594 (2005), section 1234(b), *available at http://www.ferc.gov/industries/electric/indus-act/joint-boards/final-cong-rpt.pdf.*

[112] Variable costs also include costs associated with operation and maintenance and costs of operating a pollution control and/or emission allowance charges.

[113] North American Electric Reliability Corporation, *History of NERC,* at 1 (2013), *available at http://www.nerc.com/AboutNERC/Documents/History%20AUG13.pdf.*

[114] Federal Energy Regulatory Commission, *Energy Primer: A Handbook of Energy Market Basics,* at 39 (2012), *available at http://www.ferc.gov/market-oversight/guide/energy-primer.pdf.*

[115] The Federal Power Commission, a precursor to FERC, recommended ''the formation of a council on power coordination made up of representatives from each of the nation's regional coordinating organizations, to exchange and disseminate information and to review, discuss and assist in resolving interregional coordination matters.'' North American Electric Reliability Corporation, *History of NERC,* at 1 (2013), *available at http://www.nerc.com/AboutNERC/Documents/History%20AUG13.pdf.*

[116] North American Electric Reliability Corporation, *History of NERC,* at 2 (2013), *available at http://www.nerc.com/AboutNERC/Documents/History%20AUG13.pdf.*

[117] North American Electric Reliability Corporation, *History of NERC,* at 4 (2013), *available at http://www.nerc.com/AboutNERC/Documents/History%20AUG13.pdf.*

[118] North American Electric Reliability Corporation, *History of NERC,* at 3 (2013), *available at http://www.nerc.com/AboutNERC/Documents/History%20AUG13.pdf.*

[119] U.S.-Canada Power System Outage Task Force, *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations,* at 1 (Apr. 2004), *available at http://www.ferc.gov/industries/electric/indus-act/reliability/blackout/ch1-3.pdf.* The outage impacted areas within Ohio, Michigan, Pennsylvania, New York, Vermont, Massachusetts, Connecticut, New Jersey, and the Canadian province of Ontario. *Id.*

[120] U.S.-Canada Power System Outage Task Force, *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations,* at 2 (Apr. 2004), *available at http://www.ferc.gov/industries/electric/indus-act/reliability/blackout/ch1-3.pdf.*

[121] *Mandatory Reliability Standards for the Bulk-Power System,* Order No. 693, 118 FERC ¶ 61,218, at P 3 (2007) (citing 16 U.S.C. 824o(e)(3)).

[122] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards,* Order No. 672, 114 FERC ¶ 61,104 (2006).

[123] North American Electric Reliability Corporation, *Frequently Asked Questions,* at 2 (Aug. 2013), *available at http://www.nerc.com/AboutNERC/Documents/NERC%20FAQs%20AUG13.pdf.*

regional entities.[124] These regional entities include Florida Reliability Coordinating Council (FRCC), Midwest Reliability Organization (MRO), Northeast Power Coordinating Council (NPCC), Reliability First Corporation (RFC), SERC Reliability Corporation (SERC), Southwest Power Pool, RE (SPP), Texas Reliability Entity (TRE), and Western Electricity Coordinating Council (WECC).[125] Regional entity members come from all segments of the electric industry.[126] NERC delegates authority, with FERC approval, to these regional entities to enforce reliability standards, both national and regional reliability standards, and engage in other standards-related duties delegated to them by NERC.[127] NERC ensures that there is a consistency of application of delegated functions with appropriate regional flexibility.[128] NERC divides the country into assessment areas and annually analyzes the reliability, adequacy, and associated risks that may affect the upcoming summer, winter, and long-term, 10-year period. Multiple other entities such as FERC, the Department of Energy, state public utility commissions, ISOs/RTOs,[129] and other planning authorities also consider the reliability of the electric system. There are numerous remedies that can be utilized to solve a potential reliability problem, including long-term planning, transmission system upgrades, installation of new generating capacity, demand response, and other demand side actions.

4. Modern Electric System Trends

Today, the electricity sector is undergoing a period of intense change. Fossil fuels—such as coal, natural gas, and oil—have historically provided a large percentage of electricity in the U.S., along with nuclear power, with smaller amounts provided by other types of generation, including renewables such as wind, solar, and hydroelectric power. Coal provided the largest percentage of the fossil fuel generation.[130] In recent years, the nation has seen a sizeable increase in renewable generation such as wind and solar, as well as a shift from coal to natural gas.[131] In 2013, fossil fuels supplied 67 percent of U.S. electricity,[132] but the amount of renewable generation capacity continued to grow.[133] From 2007 to 2014, use of lower- and zero-carbon energy sources such as wind and solar grew, while other major energy sources such as coal and petroleum generally experienced declines.[134] Renewable electricity generation, including from large hydro-electric projects, grew from 8 percent to 13 percent over that time period.[135] Between 2000 and 2013, approximately 90 percent of new power generation capacity built in the U.S. came in the form of natural gas or RE facilities.[136] In 2015, the U.S. Energy Information Administration (EIA) projected the need for 28.4 GW of additional base load or intermediate load generation capacity through 2020.[137] The vast majority of this new electric capacity (20.4 GW) is already under development (under construction or in advanced planning), with approximately 0.7 GW of new coal-fired capacity, 5.5 GW of new nuclear capacity, and 14.2 GW of new NGCC capacity already in development.

While the change in the resource mix has accelerated in recent years, wind, solar, other renewables, and EEresources have been reliably participating in the electric sector for a number of years. This rapid development of non-fossil fuel resources is occurring as much of the existing power generation fleet in the U.S. is aging and in need of modernization and replacement. In 2025, the average age of the coal-fired generating fleet is projected to be 49 years old, and 20 percent of those units would be more than 60 years old if they remain in operation at that time. In its *2013 Report Card for America's Infrastructure,* the American Society for Civil Engineers noted that ''America relies on an aging electrical grid and pipeline distribution systems, some of which originated in the 1880s.'' [138] While there has been an

[124] Federal Energy Regulatory Commission, *Energy Primer: A Handbook of Energy Market Basics,* at 49–50 (2012), *available at http://www.ferc.gov/market-oversight/guide/energy-primer.pdf.*

[125] Federal Energy Regulatory Commission, *Energy Primer: A Handbook of Energy Market Basics,* at 50 (2012), *available at http://www.ferc.gov/market-oversight/guide/energy-primer.pdf.*

[126] North American Electric Reliability Corporation, *Key Players, available at http://www.nerc.com/AboutNERC/keyplayers/Pages/default.aspx* (last visited Mar. 12, 2015). ''The members of the regional entities come from all segments of the electric industry: investor-owned utilities; federal power agencies; rural electric cooperatives; state, municipal and provincial utilities; independent power producers; power marketers; and end-use customers.'' *Id.*

[127] North American Electric Reliability Corporation, *Frequently Asked Questions,* at 5 (2013), *available at http://www.nerc.com/About NERC/Documents/NERC%20FAQs%20AUG13.pdf.* For example, a regional entity may propose reliability standards, including regional variances or regional reliability standards required to maintain and enhance electric service reliability, adequacy, and security in the region. *See, e.g., Amended and Restated Delegation Agreement Between North American Reliability Corporation and Midwest Reliability Organization, Bylaws of the Midwest Reliability Organization, Inc.,* Section 2.2 (2012), *available at http://www.nerc.com/Filings Orders/us/Regional%20Delegation%20Agreements %20DL/MRO_RDA_Effective_20130612.pdf.*

[128] North American Electric Reliability Corporation, *Frequently Asked Questions,* at 5 (2013), *available at http://www.nerc.com/AboutNERC/Documents/NERC%20FAQs%20AUG13.pdf.*

[129] ISOs/RTOs plan for system needs by ''effectively managing the load forecasting, transmission planning, and system and resource planning functions.'' For example, the New York Independent System Operator (NYISO) conducts reliability planning studies, which ''are used to assess current reliability needs based on user trends and historical energy use.'' NYISO, *Planning Studies, available at http://www.nyiso.com/public/markets_operations/services/planning/planning_studies/index.jsp. See also* PJM, *Reliability Assessments, available at https://www.pjm.com/planning/rtep-development/reliability-assessments.aspx* (stating that the PJM ''Regional Transmission Expansion Planning (RTEP) process includes the development of periodic reliability assessments to address specific system reliability issues in addition to the ongoing expansion planning process for the interconnection process of generation and merchant transmission.'').

[130] U.S. Energy Information Administration, ''Table 7.2b Electricity Net Generation: Electric Power Sector'' data from Monthly Energy Review May 2015, *available at http://www.eia.gov/totalenergy/data/monthly/pdf/sec7_6.pdf* (last visited May 26, 2015).

[131] U.S. Energy Information Administration, ''Table 7.2b Electricity Net Generation: Electric Power Sector'' data from Monthly Energy Review May 2015, release data April 25, 2014, *available at http://www.eia.gov/totalenergy/data/monthly/pdf/sec7_6.pdf* (last visited May 26, 2015).

[132] U.S. Energy Information Administration, ''Table 7.2b Electricity Net Generation: Electric Power Sector'' data from Monthly Energy Review May 2015, release data April 25, 2014, *available at http://www.eia.gov/totalenergy/data/monthly/pdf/sec7_6.pdf* (last visited May 26, 2015).

[133] Based on Table 6.3 (New Utility Scale Generating Units by Operating Company, Plant, Month, and Year) of the U.S. Energy Information Administration (EIA) Electric Power Monthly, data for December 2013, for the following RE sources: solar, wind, hydro, geothermal, landfill gas, and biomass. Available at *http://www.eia.gov/electricity/monthly/epm_table_grapher.cfm?t=epmt_6_03.*

[134] U.S. Energy Information Administration, ''Table 7.2b Electricity Net Generation: Electric Power Sector'' data from Monthly Energy Review May 2015, *available at http://www.eia.gov/totalenergy/data/monthly/pdf/sec7_6.pdf* (last visited May 26, 2015).

[135] Bloomberg New Energy Finance and the Business Council for Sustainable Energy, *2015 Factbook: Sustainable Energy in America,* at 16 (2015), *available at http://www.bcse.org/images/2015%20Sustainable%20Energy%20in %20America%20Factbook.pdf.* Bloomberg gave projections for 2014 values, accounting for seasonality, based on latest monthly values from EIA (data available through October 2014).

[136] Energy Information Administration, *Electricity: Form EIA–860 detailed data* (Feb. 17, 2015), *available at http://www.eia.gov/electricity/data/eia860/.*

[137] EIA, *Annual Energy Outlook for 2015 with Projections to 2040, Final Release, available at http://www.eia.gov/forecasts/AEO/pdf/0383(2015).pdf.* The AEO numbers include projects that are under development and model-projected nuclear, coal, and NGCC projects.

[138] American Society for Civil Engineers, *2013 Report Card for America's Infrastructure* (2013), *available at http://www.infrastructurereportcard.org/energy/.*

increased investment in electric transmission infrastructure since 2005, the report also found that ''ongoing permitting issues, weather events, and limited maintenance have contributed to an increasing number of failures and power interruptions.'' [139] However, innovative technologies have increasingly entered the electric energy space, helping to provide new answers to how to meet the electricity needs of the nation. These new technologies can enable the nation to answer not just questions as to how to reliably meet electricity demand, but also how to meet electricity demand reliably and cost-effectively with the lowest possible emissions and the greatest efficiency.

Natural gas has a long history of meeting electricity demand in the U.S., with a rapidly growing role as domestic supplies of natural gas have dramatically increased. Natural gas net generation increased by approximately 32 percent between 2005 and 2014.[140] In 2014, natural gas accounted for approximately 27 percent of net generation.[141] EIA projects that this demand growth will continue with its *Annual Energy Outlook 2015* (AEO 2015) Reference case forecasting that natural gas will produce 31 percent of U.S. electric generation in 2040.[142]

Renewable sources of electric generation also have a history of meeting electricity demand in the U.S. and are expected to have an increasing role going forward. A series of energy crises provided the impetus for RE development in the early 1970s. The OPEC oil embargo in 1973 and oil crisis of 1979 caused oil price spikes, more frequent energy shortages, and significantly affected the national and global economy. In 1978, partly in response to fuel security concerns, Congress passed the Public Utilities Regulatory Policies Act (PURPA) which required local electric utilities to buy power from qualifying facilities (QFs).[143] QFs were either cogeneration facilities [144] or small generation resources that use renewables such as wind, solar, biomass, geothermal, or hydroelectric power as their primary fuels.[145] Through PURPA, Congress supported the development of more RE generation in the U.S. States have also taken a significant lead in requiring the development of renewable resources. In particular, a number of states have adopted renewable portfolio standards (RPS). As of 2013, 29 states and the District of Columbia have enforceable RPS or similar laws.[146]

Use of RE continues to grow rapidly in the U.S. In 2013, electricity generated from renewable technologies, including conventional hydropower, represented 13 percent of total U.S. electricity, up from 9 percent in 2005.[147] In 2013, U.S. non-hydro RE capacity for the total electric power industry exceeded 80,000 MW, reflecting a fivefold increase in just 15 years.[148] In particular, there has been substantial growth in the wind and photovoltaic (PV) markets in the past decade. Since 2009, U.S. wind generation has tripled and solar generation has grown twenty-fold.[149]

The global market for RE is projected to grow to $460 billion per year by 2030.[150] RE growth is further encouraged by the significant amount of existing natural resources that can support RE production in the U.S.[151] In the Energy Information Administration's Annual Energy Outlook 2015, RE generation grows substantially from 2013 to 2040 in the reference case and all alternative cases.[152] In the reference case, RE generation increases by more than 70 percent from 2013 to 2040 and accounts for over one-third of new generation capacity.[153]

Price pressures caused by oil embargoes in the 1970s also brought the issues of conservation and EE to the forefront of U.S. energy policy.[154] This trend continued in the early 1990s. EE has been utilized to meet energy demand to varying levels since that time. As of April 2014, 25 states [155] have ''enacted long-term (3+ years), binding energy savings targets, or energy efficiency resource standards (EERS).'' [156] Funding for EE programs has grown rapidly in recent years, with budgets for electric efficiency programs totaling $5.9 billion in 2012.[157]

---

139 American Society for Civil Engineers, *2013 Report Card for America's Infrastructure* (2013), *available at http://www.infrastructurereportcard.org/energy/.*

140 U.S. Energy Information Administration (EIA), *Electric Power Monthly: Table 1.1 Net Generation by Energy Source: Total (All Sectors), 2005-February 2015* (2015), *available athttp://www.eia.gov/electricity/monthly/epm_table_grapher.cfm?t=epmt_1_1* (last visited May 26, 2015).

141 *Id.*

142 U.S. Energy Information Administration (EIA), *Annual Energy Outlook 2015 with Projections to 2040,* at 24–25 (2015), *available at http://www.eia.gov/forecasts/aeo/pdf/0383(2015).pdf.* According to the EIA, the reference case assumes, ''Real gross domestic product (GDP) grows at an average annual rate of 2.4% from 2013 to 2040, under the assumption that current laws and regulations remain generally unchanged throughout the projection period. North Sea Brent crude oil prices rise to $141/barrel (bbl) (2013 dollars) in 2040.'' *Id.* at 1. The EIA provides complete projection tables for the reference case in Appendix A of its report.

143 Casazza, J. and Delea, F., *Understanding Electric Power Systems,* IEEE Press, at 220–221 (2d ed. 2010).

144 Cogeneration facilities utilize a single source of fuel to produce both electricity and another form of energy such as heat or steam. Casazza, J. and Delea, F., *Understanding Electric Power Systems,* IEEE Press, at 220–221 (2d ed. 2010).

145 Casazza, J. and Delea, F., *Understanding Electric Power Systems,* IEEE Press, at 220–221 (2d ed. 2010).

146 U.S. Energy Information Administration (EIA), *Annual Energy Outlook 2014 with Projections to 2040,* at LR–5 (2014), *available at http://www.eia.gov/forecasts/aeo/pdf/0383(2014).pdf* (last visited May 26, 2015).

147 Energy Information Administration, Annual Energy Outlook 2015 with Projections to 2040, at ES–6 (2014) and Energy Information Administration, Monthly Energy Review, May 2015, Table 7.2b, *available at http://www.eia.gov/totalenergy/data/monthly/pdf/sec7_6.pdf.*

148 Non-hydro RE capacity for the total electric power industry was more than 16,000 megawatts (MW) in 1998. Energy Information Administration, 1990–2013 Existing Nameplate and Net Summer Capacity by Energy Source Producer Type and State (EIA–860), *available at http://www.eia.gov/electricity/data/state/.*

149 Energy Information Administration, Monthly Energy Review, May 2015, Table 7.2b, *available at http://www.eia.gov/totalenergy/data/monthly/pdf/sec7_6.pdf.*

150 ''Global Renewable Energy Market Outlook.'' Bloomberg New Energy Finance (Nov. 16, 2011), *available at http://bnef.com/WhitePapers/download/53.*

151 Lopez et al., NREL, ''U.S. Renewable Energy Technical Potentials: A GIS-Based Analysis,'' (July 2012).

152 Energy Information Administration, Annual Energy Outlook 2015 with Projections to 2040, at 25 (2015), *available at http://www.eia.gov/forecasts/aeo/pdf/0383(2015).pdf.*

153 Energy Information Administration, Annual Energy Outlook 2015 with Projections to 2040, at ES–6 (2015), *available at http://www.eia.gov/forecasts/aeo/pdf/0383(2015).pdf* (last visited May 27, 2015).

154 Edison Electric Institute, *Making a Business of Energy Efficiency: Sustainable Business Models for Utilities,* at 1 (2007), *available at http://www.eei.org/whatwedo/PublicPolicyAdvocacy/StateRegulation/Documents/Making_Business_Energy_Efficiency.pdf.* Congress passed legislation in the 1970s that jumpstarted energy efficiency in the U.S. For example, President Ford signed the Energy Policy and Conservation Act (EPCA) of 1975—the first law on the issue. EPCA authorized the Federal Energy Administration (FEA) to ''develop energy conservation contingency plans, established vehicle fuel economy standards, and authorized the creation of efficiency standards for major household appliances.'' Alliance to Save Energy, *History of Energy Efficiency,* at 6 (2013) (citing Anders, *''The Federal Energy Administration,''* 5; Energy Policy and Conservation Act, S. 622, 94th Cong. (1975–1976)), *available at https://www.ase.org/sites/ase.org/files/resources/Media%20browser/ee_commission_history_report_2–1–13.pdf.*

155 American Council for an Energy-Efficient Economy, *State Energy Efficiency Resource Standards (EERS)* (2014), *available at http://aceee.org/files/pdf/policy-brief/eers-04–2014.pdf.* ACEEE did not include Indiana (EERS eliminated), Delaware (EERS pending), Florida (programs funded at levels far below what is necessary to meet targets), Utah, or Virginia (voluntary standards) in its calculation.

156 American Council for an Energy-Efficient Economy, *State Energy Efficiency Resource Standards (EERS)* (2014), *available at http://aceee.org/files/pdf/policy-brief/eers-04–2014.pdf.*

157 American Council for an Energy-Efficient Economy, *The 2013 State Energy Efficiency*

Continued

Advancements and innovation in power sector technologies provide the opportunity to address CO_2 emission levels at affected power plants while at the same time improving the overall power system in the U.S. by lowering the carbon intensity of power generation, and ensuring a reliable supply of power at a reasonable cost.

E. Clean Air Act Regulations for Power Plants

In this section, we provide a general description of major CAA regulations for power plants. We refer to these in later sections of this preamble.

1. Title IV Acid Rain Program

The EPA's Acid Rain Program, established in 1990 under Title IV of the CAA, addresses the presence of acidic compounds and their precursors (*i.e.,* SO_2 and NO_X), in the atmosphere by targeting ''the principal sources'' of these pollutants through an SO_2 cap-and-trade program for fossil-fuel fired power plants and through a technology based NO_X emission limit for certain utility boilers. Altogether, Title IV was designed to achieve reductions of ten million tons of annual SO_2 emissions, and, in combination with other provisions of the CAA, two million tons of annual NO_X emissions.[158]

The SO_2 cap-and-trade program was implemented in two phases. The first phase, beginning in 1995, targeted one-hundred and ten named power plants, including specific generator units at each plant, requiring the plants to reduce their cumulative emissions to a specific level.[159] Under certain conditions, the owner or operator of a named power plant could reassign an affected unit's reduction requirement to another unit and/or request an extension of two years for meeting the requirement.[160] Congress also established an energy conservation and RE reserve from which up to 300,000 allowances could be allocated for qualified energy conservation measures or qualified RE.[161]

The second phase, beginning in 2000, expanded coverage to more than 2,000 generating units and set a national cap at 8.90 million tons.[162] Generally, allowances were allocated at a rate of 1.2 lbs/mmBtu multiplied by the unit's baseline and divided by 2000.[163] However, bonus allowances could be awarded to certain units.

Title IV also required the EPA to hold or sponsor annual auctions and sales of allowances for a small portion of the total allowances allocated each year. This ensured that some allowances would be directly available for new sources, including independent power production facilities.[164]

The provisions of the EPA's Acid Rain Program are implemented through permits issued under the EPA's Title V Operating Permit Program.[165] In accordance with Title IV, moreover, each Title V permit application must include a compliance plan for the affected source that details how that source expects to meet the requirements of Title IV.[166]

2. Transport Rulemakings

CAA section 110(a)(2)(D)(i)(I), the ''Good Neighbor Provision,'' requires SIPs to prohibit emissions that ''contribute significantly to nonattainment . . . or interfere with maintenance'' of the NAAQS in any other state.[167] If the EPA finds that a state has failed to submit an approvable SIP, the EPA must issue a federal implementation plan (FIP) to prohibit those emissions ''at any time'' within the next two years.[168]

In three major rulemakings—the NO_X SIP Call,[169] the Clean Air Interstate Rule (CAIR),[170] and the Cross State Air Pollution Rule (CSAPR) [171]—the EPA has attempted to delineate the scope of the Good Neighbor Provision. These rulemakings have several features in common. Although the Good Neighbor Provision does not speak specifically about EGUs, in all three rulemakings, the EPA set state emission ''budgets'' for upwind states based in part on emissions reductions achievable by EGUs through application of cost-effective controls. Each rule also adopted a phased approach to reducing emissions with both interim and final goals.

a. *NO_X SIP Call.* In 1998, the EPA promulgated the NO_X SIP Call, which required 23 upwind states to reduce emissions of NO_X that would impact downwind areas with ozone problems. The EPA determined emission reduction requirements based on reductions achievable through ''highly cost-effective'' controls—*i.e.,* controls that would cost on average no more than $2,000 per ton of emissions reduced.[172] The EPA determined that a uniform emission rate on large EGUs coupled with a cap-and-trade program was one such set of highly cost-effective controls.[173] Accordingly, the EPA established an interstate cap-and-trade program—the NO_X Budget Trading Program—as a mechanism for states to reduce emissions from EGUs and other sources in a highly cost-effective manner. The D.C. Circuit upheld the NO_X SIP Call in most significant respects, including its use of costs to apportion emission reduction responsibilities.[174]

b. *Clean Air Interstate Rule (CAIR).* In 2005, the EPA promulgated CAIR, which required 28 upwind states to reduce emissions of NO_X and SO_2 that would impact downwind areas with projected nonattainment and maintenance problems for ozone and $PM_{2.5}$. The EPA determined emission reduction requirements based on ''controls that are known to be highly cost effective for EGUs.'' [175] The EPA established cap-and-trade programs for sources of NO_X and SO_2 in states that chose to participate in the trading programs via their SIPs and for states ultimately subject to a FIP.[176] As relevant here, the D.C. Circuit remanded CAIR in *North Carolina* v. *EPA* due to in part the structure of its interstate trading provisions and the way in which EPA applied the cost-effective standard, but kept the rule in place while the EPA developed an acceptable substitute.[177]

c. *Cross-state Air Pollution Rule (CSAPR).* In 2011, the EPA promulgated CSAPR, which required 27 upwind states to reduce emissions of NO_X and SO_2 that would impact downwind areas with projected nonattainment and

Scorecard, at 17 (Nov. 2013), *available at http://aceee.org/sites/default/files/publications/researchreports/e13k.pdf.*

[158] 42 U.S.C. 7651(b).

[159] 42 U.S.C. 7651c (Table A).

[160] 42 U.S.C. 7651c(b) and (d).

[161] 42 U.S.C. 7651c(f) and (g).

[162] U.S. Dept. of Energy, Energy Information Administration, ''The Effects of Title IV of the Clean Air Act Amendments of 1990 on Electric Utilities: An Update,'' p. vii. (March 1997).

[163] *See* 42 U.S.C. 7651d.

[164] 42 U.S.C. 7651o.

[165] 42 U.S.C. 7651g.

[166] Such plans may simply state that the owner or operator expects to hold sufficient allowances or, in the case of alternative compliance methods, must provide a ''comprehensive description of the schedule and means by which the unit will rely on one or more alternative methods of compliance in the manner and time authorized under [Title IV].'' 42 U.S.C. 7651g(b).

[167] 42 U.S.C. 7410(a)(2)(D)(i)(I).

[168] *EPA* v. *EME Homer City Generation, L.P.,* 134 S. Ct. 1584, 1600–01 (2014) (citing 42 U.S.C. 7410(c)).

[169] 63 FR 57356 (Oct. 27, 1998).

[170] 70 FR 25162 (May 12, 2005).

[171] 76 FR 48208 (Aug. 8, 2011).

[172] 63 FR at 57377–78.

[173] 63 FR at 57377–78. In addition to EGUs, the NO_X SIP Call also set budgets based on highly cost-effective emission reductions from certain other large sources. *Id.*

[174] *Michigan* v. *EPA,* 213 F.3d 663 (D.C. Cir. 2000).

[175] 70 FR at 25163.

[176] 70 FR at 25273–75; 71 FR 25328 (April 28, 2006).

[177] 531 F.3d 896, 917–22 (D.C. Cir. 2008), *modified on rehearing* 550 F.3d 1176, 1178 (D.C. Cir. 2008).

maintenance problems for ozone and $PM_{2.5}$. The EPA determined emission reduction requirements based in part on the reductions achievable at certain cost thresholds by EGUs in each state, with certain provisions developed to account for the need to ensure reliability of the electric generating system.[178] In the same action establishing these emission reduction requirements, the EPA promulgated FIPs that subjected states to trading programs developed to achieve the necessary reductions within each state.[179] The U.S. Supreme Court upheld the EPA's use of cost to set emission reduction requirements, as well as its authority to issue the FIPs.[180]

3. Clean Air Mercury Rule

On March 15, 2005, the EPA issued a rule to control mercury (Hg) emissions from new and existing fossil fuel-fired power plants under CAA section 111(b) and (d). The rule, known as the Clean Air Mercury Rule (CAMR), established, in relevant part, a nationwide cap-and-trade program under CAA section 111(d), which was designed to complement the cap-and-trade program for SO_2 and NO_X emissions under the Clean Air Interstate Rule (CAIR), discussed above.[181] Though CAMR was later vacated by the D.C. Circuit on account of the EPA's flawed CAA section 112 delisting rule, the court declined to reach the merits of the EPA's interpretation of CAA section 111(d).[182] Accordingly, CAMR continues to be an informative model for a cap-and-trade program under CAA section 111(d).

The cap-and-trade program in CAMR was designed to take effect in two phases: in 2010, the cap was set at 38 tons of mercury per year, and in 2018, the cap would be lowered to 15 tons per year. The Phase I cap was set at a level reflecting the co-benefits of CAIR as determined through economic and environmental modeling.[183] For the more stringent Phase II cap, the EPA projected that sources would "install SCR [selective catalytic reduction] to meet their SO_2 and NO_X requirements and take additional steps to address the remaining Hg reduction requirements under CAA section 111, including adding Hg-specific control technologies (model applies ACI [activated carbon injection]), additional scrubbers and SCR, dispatch changes, and coal switching." [184] Based on this analysis, EPA determined that the BSER "refers to the combination of the cap-and-trade mechanism and the technology needed to achieve the chosen cap level." [185]

To accompany the nationwide emissions cap, the EPA also assigned a statewide emissions budget for mercury. Pursuant to CAA section 111(d), states would be required to submit plans to the EPA "detailing the controls that will be implemented to meet its specified budget for reductions from coal-fired Utility Units." [186] Of course, states were "not required to adopt and implement" the emission trading program, "but they [were] required to be in compliance with their statewide Hg emission budget." [187]

4. Mercury Air Toxics Rule

On February 16, 2012, the EPA issued the MATS rule (77 FR 9304) to reduce emissions of toxic air pollutants from new and existing coal- and oil-fired EGUs. The MATS rule will reduce emissions of heavy metals, including mercury, arsenic, chromium, and nickel; and acid gases, including hydrochloric acid and hydrofluoric acid. These toxic air pollutants, also known as hazardous air pollutants or air toxics, are known to cause, or suspected of causing, nervous system damage, cancer, and other serious health effects. The MATS rule will also reduce SO_2 and fine particle pollution, which will reduce particle concentrations in the air and prevent thousands of premature deaths and tens of thousands of heart attacks, bronchitis cases and asthma episodes.

New or reconstructed EGUs (*i.e.,* sources that commence construction or reconstruction after May 3, 2011) subject to the MATS rule are required to comply by April 16, 2012 or upon startup, whichever is later.

Existing sources subject to the MATS rule were required to begin meeting the rule's requirements on April 16, 2015. Controls that will achieve the MATS performance standards are being installed on many units. Certain units, especially those that operate infrequently, may be considered not worth investing in given today's electricity market, and are closing. The final MATS rule provided a foundation on which states and other permitting authorities could rely in granting an additional, fourth year for compliance provided for by the CAA. States report that these fourth year extensions are being granted. In addition, the EPA issued an enforcement policy that provides a clear pathway for reliability-critical units to receive an administrative order that includes a compliance schedule of up to an additional year, if it is needed to ensure electricity reliability.

Following promulgation of the MATS rule, industry, states and environmental organizations challenged many aspects of the EPA's threshold determination that regulation of EGUs is "appropriate and necessary" and the final standards regulating hazardous air pollutants from EGUs. The U.S. Court of Appeals for the D.C. Circuit upheld all aspects of the MATS rule. *White Stallion Energy Center* v. *EPA,* 748 F.3d 1222 (D.C. Cir. 2014). In *Michigan* v. *EPA,* case no. 14–46, the U.S. Supreme Court reversed the portion of the D.C. Circuit decision finding the EPA was not required to consider cost when determining whether regulation of EGUs was "appropriate" pursuant to section 112(n)(1). The Supreme Court considered only the narrow question of whether the EPA erred in not considering cost when making this threshold determination. The Court's decision did not disturb any of the other holdings of the D.C. Circuit. The Court remanded the case to the D.C. Circuit for further proceedings, and the MATS rule remains in place at this time.

5. Regional Haze Rule

Under CAA section 169A, Congress "declare[d] as a national goal the prevention of any future, and the remedying of any existing, impairment of visibility" in national parks and wilderness areas that results from anthropogenic emissions.[188] To achieve this goal, Congress directed the EPA to promulgate regulations directing states to submit SIPs that "contain such emission limits, schedules of compliance and other measures as may be necessary to make reasonable progress toward meeting the national goal. . . ." [189] One such measure that Congress deemed necessary to make reasonable progress was a requirement that certain older stationary sources that cause or contribute to visibility impairment "procure, install, and operate, as expeditiously as practicable

[178] 76 FR at 48270. The EPA adopted this approach in part to comport with the D.C. Circuit's opinion in *North Carolina* v. *EPA* remanding CAIR. *Id.* at 48270–71.

[179] 76 FR at 48209–16.

[180] *EPA* v. *EME Homer City Generation, L.P.,* 134 S. Ct. 1584 (2014).

[181] *See* 70 FR 28606 (May 18, 2005).

[182] *New Jersey* v. *EPA,* 517 F.3d 574 (D.C. Cir. 2008).

[183] 70 FR 28606, at 28617. The EPA's projections under CAIR showed a significant number of affected sources would install scrubbers for SO_2 and selective catalytic reduction for NO_X on coal-fired power plants, which had the co-benefit of capturing mercury emissions. *Id.* at 28619.

[184] 70 FR 28606, at 28619.

[185] 70 FR 28606, at 28620.

[186] 70 FR 28606, at 28621.

[187] 70 FR 28606, at 28621. That said, states could "require reductions beyond those required by the [s]tate budget." *Id.* at 28621.

[188] 42 U.S.C. 7491(a)(1).

[189] 42 U.S.C. 7491(b)(2).

. . . the best available retrofit technology,'' more commonly referred to as BART.[190] When determining BART for large fossil-fuel fired utility power plants, Congress required states to adhere to guidelines to be promulgated by the EPA.[191] As with other SIP-based programs, the EPA is required to issue a FIP within two years if a state fails to submit a regional haze SIP or if the EPA disapproves such SIP in whole or in part.[192]

In 1999, the EPA promulgated the Regional Haze Rule to satisfy Congress' mandate that EPA promulgate regulations directing states to address visibility impairment.[193] Among other things, the Regional Haze Rule allows states to satisfy the Act's BART requirement either by adopting source-specific emission limitations or by adopting alternatives, such as emissions-trading programs, that achieve greater reasonable progress than would source-specific BART.[194] The Ninth Circuit and D.C. Circuit have both upheld the EPA's interpretation that CAA section 169A(b)(2) allows for BART alternatives in lieu of source-specific BART.[195] In 2005, the EPA promulgated BART Guidelines to assist states in determining which sources are subject to BART and what emission limitations to impose at those sources.[196]

The Regional Haze Rule set a goal of achieving natural visibility conditions by 2064 and requires states to revise their regional haze SIPs every ten years.[197] The first planning period, which ends in 2018, focused heavily on the BART requirement. States (or the EPA in the case of FIPs) made numerous source-specific BART determinations, and developed several BART alternatives, for utility power plants. For the next planning period, states will need to determine whether additional controls are necessary at these plants (and others that were not subject to BART) in order to make reasonable progress towards the national visibility goal.[198]

[190] 42 U.S.C. 7491(b)(2)(A).

[191] 42 U.S.C. 7491(b)(2).

[192] 42 U.S.C. 7410(c); 7491(b)(2)(A).

[193] 64 FR 35714 (July 1, 1999) (codified at 40 CFR 51.308–309).

[194] 40 CFR 51.308(e)(1) & (2).

[195] *See Utility Air Regulatory Grp.* v. *EPA,* 471 F.3d 1333 (D.C. Cir. 2006); *Ctr. for Econ. Dev.* v. *EPA,* 398 F.3d 653 (D.C. Cir. 2005); *Cent. Ariz. Water Dist.* v. *EPA,* 990 F.2d 1531 (9th Cir. 1993).

[196] 70 FR 39104 (July 6, 2005) (codified at 40 CFR pt. 51, app. Y).

[197] *See* 40 CFR 51.308(d)(1)(i)(B), (f).

[198] *See* 42 U.S.C. 7491(b)(2); 40 CFR 51.308(d)(3).

F. Congressional Awareness of Climate Change in the Context of the Clean Air Act Amendments [199]

During its deliberations on the 1970 Clean Air Act Amendments, Congress learned that ongoing pollution, including from manmade carbon dioxide, could ''threaten irreversible atmospheric and climatic changes.'' [200] At that time, Congress heard the views of scientists that carbon dioxide emissions tended to increase global temperatures, but that there was uncertainty as to the extent to which those increases would be offset by the decreases in temperatures brought about by emissions of particulates. President Nixon's Council on Environmental Quality (CEQ) reported that ''the addition of particulates and carbon dioxide in the atmosphere could have dramatic and long-term effects on world climate.'' [201] The CEQ's First Annual Report, which was transmitted to Congress, devoted a chapter to ''Man's Inadvertent Modification of Weather and Climate.'' [202] Moreover, Charles Johnson, Jr., Administrator of the Consumer Protection and Environmental Health Service, testified before the House Subcommittee on Public Health that ''the carbon dioxide balance might result in the heating up of the atmosphere whereas the reduction of the radiant energy through particulate matter released to the atmosphere might cause reduction in radiation that reaches the earth.'' [203] Administrator Johnson explained that the Nixon Administration was ''concerned . . . that neither of these things happen'' and that they were ''watching carefully the kind of prognosis, the kind of calculations that the scientists make to look at the continuous balance between heat and cooling of the total earth's atmosphere.'' [204] He concluded that ''[w]hat we are trying to do, however, in terms of our air pollution effort should have a very salutary effect on either of these.'' [205]

Scientific reports on climatic change continued to gain traction in Congress through the mid-1970s, including while Congress was considering the 1977 CAA Amendments. However, uncertainty continued as to whether the increased warming brought about by carbon dioxide emissions would be offset by cooling brought about by particulate emissions.[206] Congress ordered, as part of the 1977 CAA Amendments, the National Oceanic and Atmospheric Administration to research and monitor the stratosphere ''for the purpose of early detection of changes in the stratosphere and climatic effects of such changes.'' [207]

Between the 1977 and 1990 Clean Air Act Amendments, scientific uncertainty yielded to the predominant view that global warming ''was likely to dominate on time scales that would be significant to human societies.'' [208] In fact, as part of the 1990 Clean Air Act Amendments, Congress specifically required the EPA to collect data on carbon dioxide emissions—the most significant of the GHGs—from all sources subject to the

[199] The following discussion is not meant to be exhaustive. There are many other instances outside the context of the CAA, before and after 1970, when Congress discussed or was presented with evidence on climate change.

[200] Sen. Scott, S. Debate on S. 4358 (Sept. 21, 1970), 1970 CAA Legis. Hist. at 349.

[201] Council on Environmental Quality, ''The First Annual Report of the Council on Environmental Quality,'' p. 110 (Aug. 1970) (recognizing also that ''[man] can increase the carbon dioxide content of the atmosphere by burning fossil fuels'' and postulating that an increase in the earth's average temperature by about 2° to 3° F ''could in a period of decades, lead to the start of substantial melting of ice caps and flooding of coastal regions.'').

[202] Council on Environmental Quality, ''The First Annual Report of the Council on Environmental Quality,'' p. 93–104 (Aug. 1970)

[203] Testimony of Charles Johnson, Jr., Administrator of the Consumer Protection and Environmental Health Service (Administration Testimony), Hearing of the House Subcommittee on Public Health and Welfare (Mar. 16, 1970), 1970 CAA Legis. Hist. at 1381.

[204] Testimony of Charles Johnson, Jr., Administrator of the Consumer Protection and Environmental Health Service (Administration Testimony), Hearing of the House Subcommittee on Public Health and Welfare (Mar. 16, 1970), 1970 CAA Legis. Hist. at 1381.

[205] Testimony of Charles Johnson, Jr., Administrator of the Consumer Protection and Environmental Health Service (Administration Testimony), Hearing of the House Subcommittee on Public Health and Welfare (Mar. 16, 1970), 1970 CAA Legis. Hist. at 1381.

[206] For instance, while scientists, such as Stephen Schneider of the National Center for Atmospheric Research, testified that ''manmade pollutants will affect the climate,'' they believed that we would ''see a general cooling of the Earth's atmosphere.'' Rep. Scheuer, H. Debates on H.R. 10498 (Sept. 15, 1976), 1977 CAA Legis. Hist. at 6477. Additionally, the Department of Transportation's climatic impact assessment program and the Climatic Impact Committee of the National Research Council, National Academies of Science and Engineering both reported that ''warming or cooling'' could occur. *Id.* at 6476. *See also* Sen. Bumpers, S. Debates on S. 3219 (August 3, 1976), 1977 CAA Legis. Hist. at 5368 (inserting ''Summary of Statements Received [in the Subcommittee on the Environment and the Atmosphere] from Professional Societies for the Hearings on Effects of Chronic Pollution'' into the record, which noted that ''there is near unamity [sic] that carbon dioxide concentrations in the atmosphere are increasing rapidly.'').

[207] ''Clean Air Act Amendments of 1977,'' § 125, 91 Stat. at 728.

[208] Peterson, Thomas C., William M. Connolley, and John Fleck, ''The Myth of the 1970s Global Cooling Scientific Consensus,'' Bulletin of the American Meteorological Society, p. 1326 (September 2008), *available at http://journals.ametsoc.org/doi/pdf/10.1175/2008BAMS2370.1.*

newly enacted operating permit program under Title V.[209] Although Congress did not require the EPA to take immediate action to address climate change, Congress did identify certain tools that were particularly helpful in addressing climate change in the utility power sector. The Senate report discussing the acid rain provisions of Title IV noted that some of the measures that would reduce coal-fired power plant emissions of the precursors to acid rain would also reduce those facilities' emissions of CO_2. The report stated:

> Energy efficiency is a crucial tool for controlling the emissions of carbon dioxide, the gas chiefly responsible for the intensification of the atmospheric 'greenhouse effect.' In the last several years, the Committee has received extensive scientific testimony that increases in the human-caused emissions of carbon dioxide and other greenhouse gases will lead to catastrophic shocks in the global climate system. Accordingly, new title IV shapes an acid rain reduction policy that encourages energy efficiency and other policies aimed at controlling greenhouse gases.[210]

Similarly, Title IV provisions to encourage RE were justified because ''renewables not only significantly curtail sulfur dioxide emissions, but they emit little or no nitrogen oxides and carbon dioxide''.[211]

G. International Agreements and Actions

In this final rule, the U.S. is taking action to limit GHGs from one of its largest emission sources. Climate change is a global problem, and the U.S. is not alone in taking action to address it. The UNFCCC[212] is the international treaty under which countries (called ''Parties'') cooperatively consider what can be done to limit anthropogenic climate change[213] and adapt to climate change impacts. Currently, there are 195 Parties to the UNFCCC, including the U.S. The Conference of the Parties (COP) meets annually and is currently considering commitments countries can make to limit emissions after 2020. The 2015 COP will be in Paris and is expected to represent an historic step for climate change mitigation. The Parties to the UNFCC will meet to establish a climate agreement that applies to all countries and focuses on reducing GHG emissions. Such an outcome would send a beneficial signal to the markets and civil society about global action to address climate change.

Many countries have announced their intended post-2020 commitments already, and other countries are expected to do so before December. In April 2015, the U.S. announced its commitment to reduce GHG emissions 26–28 percent below 2005 levels by 2025.[214]

As Parties to both the UNFCCC and the Kyoto Protocol,[215] the European Union (EU) and member countries have taken aggressive action to reduce GHG emissions.[216] EU initiatives to reduce GHG emissions include the EU Emissions Trading System, legislation to increase the adoption of RE sources, strengthened EE targets, vehicle emission standards, and support for the development of CCS technology for use by the power sector and other industrial sources. In 2009, the EU announced its ''20–20–20 targets,'' including a 20 percent reduction in GHG emissions from 1990 levels by 2020, an increase of 20 percent in the share of energy consumption produced by renewable resources, and a 20 percent improvement in EE. In March 2015, the EU announced its commitment to reduce domestic GHG emissions by at least 40% from 1990 levels by 2030.

Recently, China has also agreed to take action to address climate change. In November 2014, in a joint announcement by President Obama and China's President Xi, China pledged to curtail GHG emissions, with emissions peaking in 2030 and then declining thereafter, and to increase the share of energy from non-carbon sources (solar, wind, hydropower, nuclear) to 20 percent by 2030.

Mexico is committed to reduce unconditionally 25 percent of its emissions of GHGs and short-lived climate pollutants (below business as usual) for the year 2030. This commitment implies a 22 percent reduction of GHG emissions and a 51 percent reduction of black carbon emissions.

Brazil has reduced its net CO_2 emissions more than any other country through a historic effort to slow forest loss. The deforestation rate in Brazil in 2014 was roughly 75 percent below the average for 1996 to 2005.[217]

Together, countries that have already announced their intended post-2020 commitments, including the U.S., China, European Union, Mexico, Russian Federation and Brazil, make up a large majority of global emissions.

President Obama's Climate Action Plan contains a number of policies and programs that are intended to cut carbon pollution that causes climate change and affects public health. The Clean Power Plan is a key component of the plan, addressing the nation's largest source of emissions in a comprehensive manner. Collectively, these policies will help spark business innovation, result in cleaner forms of energy, create jobs, and cut dependence on foreign oil. They also demonstrate to the rest of the world that the U.S. is contributing its share of the global effort that is needed to address climate change.[218] This demonstration encourages other major economies to take on similar contributions, which is critical given the global impact of GHG emissions. The State Department Special Envoy for Climate Change Todd Stern, the lead U.S. climate change negotiator, noted the connection between domestic and international action to address climate change in his speech at Yale University on October 14, 2014:

> This mobilization of American effort matters. Enormously. It matters because the United States is the biggest economy and largest historic emitter of greenhouse gases. Because, here, as in so many areas, we feel a responsibility to lead. And because here, as in so many areas, we find that American commitment is indispensable to effective international action.
>
> And make no mistake—other countries see what we are doing and are taking note. As I travel the world and meet with my

[209] ''Clean Air Act Amendments of 1990,'' § 820, 104 Stat. at 2699.

[210] Sen. Chafee, S. Debate on S. 1630 (Jan. 24, 1990), 1990 CAA Legis. Hist. at 8662.

[211] Additional Views of Rep. Markey and Rep. Moorhead, H.R. Rep. No. 101–490, at 674 (May 17, 1990).

[212] *http://unfccc.int/2860.php.*

[213] Article 2, Objective, The ultimate objective of this Convention and any related legal instruments that the Conference of the Parties may adopt is to achieve, in accordance with the relevant provisions of the Convention, stabilization of greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system. Such a level should be achieved within a time frame sufficient to allow ecosystems to adapt naturally to climate change, to ensure that food production is not threatened and to enable economic development to proceed in a sustainable manner. *http://unfccc.int/files/essential_background/convention/background/application/pdf/convention_text_with_annexes_english_for_posting.pdf*

[214] United States Cover Note to Intended Nationally Determined Contribution (INDC). Available online at: *http://www4.unfccc.int/submissions/INDC/Published%20Documents/United%20States%20of%20America/1/U.S.%20Cover%20Note%20INDC%20and%20Accompanying%20Information.pdf.*

[215] *http://unfccc.int/kyoto_protocol/items/2830.php.*

[216] *http://ec.europa.eu/clima/policies/brief/eu/index_en.htm.*

[217] *http://www.nature.com/news/stopping-deforestation-battle-for-the-amazon-1.17223.*

[218] President Obama stated, in announcing the Climate Action Plan:

> ''The actions I've announced today should send a strong signal to the world that America intends to take bold action to reduce carbon pollution. We will continue to lead by the power of our example, because that's what the United States of America has always done.'' President Obama, Climate Action Plan speech, Georgetown University, 2013. Available at *https://www.whitehouse.gov/the-press-office/2013/06/25/remarks-president-climate-change.*

counterparts, the palpable engagement of President Obama and his team has put us in a stronger, more credible position than ever before.

This final rule demonstrates to other countries that the U.S. is taking action to limit GHG emissions from its largest emission sources, in line with our international commitments. The impact of GHGs is global, and U.S. action to reduce GHG emissions complements and encourages ongoing programs and efforts in other countries.

H. Legislative and Regulatory Background for CAA Section 111

In the final days of December 1970, Congress enacted sweeping changes to the Air Quality Act of 1967 to confront an ''environmental crisis.'' [219] The Air Quality Act—which expanded federal air pollution control efforts after the enactment of the Clean Air Act of 1963—prioritized the adoption of ambient air standards but failed to target stationary sources of air pollution. As a result, ''[c]ities up and down the east coast were living under clouds of smoke and daily air pollution alerts.'' [220] In fact, ''[o]ver 200 million tons of contaminants . . . spilled into the air'' each year.[221] The 1970 CAA Amendments were designed to face this crisis ''with urgency and in candor.'' [222]

For the most part, Congress gave EPA and the states flexible tools to implement the CAA. This is best exhibited by the newly enacted programs regulating stationary sources. For these sources, Congress crafted a three-legged regime upon which the regulation of stationary sources was intended to sit.

The first prong—CAA sections 107–110—addressed what are commonly referred to as criteria pollutants, ''the presence of which in the ambient air results from numerous or diverse mobile or stationary sources'' and are determined to have ''an adverse effect on public health or welfare''.[223] Under these provisions, states would have the primary responsibility for assuring air quality within their entire geographic area but would submit plans to the Administrator for ''implementation, maintenance, and enforcement'' of national ambient air quality standards. These plans would include ''emission limitations, schedules, and timetables for compliance . . . and such other measures as may be necessary to insure attainment and maintenance'' of the national ambient air quality standards.[224]

The second prong—CAA section 111—addressed pollutants on a source category-wide basis. Under CAA section 111(b), the EPA lists source categories which ''contribute significantly to air pollution which causes or contributes to the endangerment of public health or welfare,'' And then establishes ''standards of performance'' for the new sources in the listed category.[225] For existing sources in a listed source category, CAA section 111(d) set out procedures for the establishment of federally enforceable ''emission standards'' of any pollutant not otherwise controlled under the CAA's SIP provisions or CAA section 112.

Lastly, the third prong—CAA section 112—addressed hazardous air pollutants through the establishment of national ''emission standards'' at a level which ''provides an ample margin of safety to protect the public health''.[226] All new or modified sources of any hazardous air pollutant would be required to meet these emission standards. Existing sources were required to meet the same standards or would be shut down unless they obtained a temporary EPA waiver or Presidential exemption.[227]

At its inception, CAA section 111 was intended to bear a significant weight under this three-legged regime. Indeed, by 1977, the EPA had promulgated six times as many performance standards under CAA section 111 than emission standards under CAA section 112.[228] That said, states, including Texas and New Jersey, levied ''substantial criticisms'' against the EPA for not moving rapidly enough.[229] Accordingly, the 1977 CAA Amendments were designed to ''provide a greater role for the [s]tates in standards setting under the [CAA],'' ''protect [s]tates from 'environmental blackmail' as they attempt to regulate mobile and competitive industries,'' and lastly ''provide a check on the Administrator's inaction or failure to control emissions adequately.'' [230]

At bottom, CAA section 111 rests on the definition of a standard of performance under CAA section 111(a)(1), which reads nearly the same now as it did when it was first adopted in the 1970 CAA Amendments. In 1970, Congress defined standard of performance—a term which had not previously appeared in the CAA—as

> a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction) the Administrator determines has been adequately demonstrated.[231]

Despite significant changes to this definition in 1977, Congress reversed course in 1990 and largely reinstated the original definition.[232] As presently defined, the term applies to the regulation of new and existing sources under CAA sections 111(b) and (d).[233]

The level of control reflected in the definition is generally referred to as the ''best system of emission reduction,'' or the BSER. The BSER, however, is not further defined, and only appeared after conference between the House and Senate in late 1970, and was neither discussed in the conference report nor openly debated in either chamber. Nevertheless, the originating bills from both houses shed light on its construction.

The BSER grew out of proposed language in two bills, which, for the first time, targeted air pollution from stationary sources. The House bill sought to establish national emission standards to ''prevent and control . . . emissions [of non-hazardous pollutants] to the fullest extent compatible with the available technology and economic feasibility.'' [234] The House also

[219] Sen. Muskie, S. Debate on S. 4358 (Sept. 21, 1970), 1970 CAA Legis. Hist. at 224.

[220] Sen. Muskie, S. Consideration of H.R. Conf. Rep. No. 91–1783 (Dec. 18, 1970), 1970 CAA Legis. Hist.pa at 123.

[221] Sen. Muskie, S. Debate on S. 4358 (Sept. 21, 1970), 1970 CAA Legis. Hist. at 224. These pollutants fell into five main classes of pollutants: Carbon monoxide, particulates, sulfur oxides, hydrocarbons, and nitrogen oxides. *See* Sen. Boggs, *id.* at 244.

[222] Sen. Muskie, S. Consideration of H.R. Conf. Rep. No. 91–1783 (Dec. 18, 1970), 1970 CAA Legis. Hist. at 123.

[223] ''Clean Air Act Amendments of 1970,'' Pub. L. 91–604, § 4, 84 Stat. 1676, 1678 (Dec. 31, 1970). The ''adverse effect'' criterion was later amended to refer to pollutants ''which may reasonably be anticipated to endanger public health or welfare''. *See* 42 U.S.C. 7408(a)(1)(A). Similar language is also used under the current CAA section 111. *See* 42 U.S.C. 7411(b)(1)(A).

[224] ''Clean Air Act Amendments of 1970,'' § 4, 84 Stat. at 1680.

[225] ''Clean Air Act Amendments of 1970,'' § 4, 84 Stat. at 1684.

[226] ''Clean Air Act Amendments of 1970,'' § 4, 84 Stat. at 1685.

[227] ''Clean Air Act Amendments of 1970,'' § 4, 84 Stat. at 1685.

[228] H.R. Rep. No. 95–294, at 194 (May 12, 1977).

[229] H.R. Rep. No. 95–294, at 194 (May 12, 1977).

[230] H.R. Rep. No. 95–294, at 195 (May 12, 1977).

[231] ''Clean Air Act Amendments of 1970,'' § 4, 84 Stat. at 1683.

[232] ''Clean Air Act Amendments of 1990,'' Pub. L. 101–549, § 403, 104 Stat. 2399, 2631 (Nov. 15, 1990) (retaining only the obligation to account for ''any nonair quality health and environmental impact and energy requirements'' that was added in 1977).

[233] As CAA section 111(d) was originally adopted, state plans would have established ''emission standards'' instead of ''standards of performance.'' This distinction was later abandoned in 1977 and the same term is used in both CAA sections 111(b) and (d).

[234] H.R. 17255, 91st Cong. § 5 (1970).

proposed to prohibit the construction or operation of new sources of ''extremely hazardous'' pollutants.[235] The Senate bill, on the other hand, authorized ''Federal standards of performance,'' which would ''reflect the greatest degree of emission control which the Secretary [later, the Administrator] determines to be achievable through application of the latest available control technology, processes, operating methods, or other alternatives.'' [236] The Senate also would have authorized ''national emission standards'' for hazardous air pollution and other ''selected air pollution agents.'' [237]

After conference, CAA section 111 emerged as one of the CAA's three programs for regulating stationary sources. In defining the newly formed ''standards of performance,'' Congress appeared to merge the various ''means of preventing and controlling air pollution'' under the Senate bill with the consideration of costs that was central to the House bill into the BSER. At the time, however, this definition only applied to new sources under CAA section 111(b).

To regulate existing sources, Congress collapsed section 114 of the Senate bill into CAA section 111(d).[238] Section 114 of the Senate bill established emission standards for ''selected air pollution agents,'' and was intended to bridge the gap between criteria pollutants and hazardous air pollutants. As proposed, the Senate identified fourteen substances for regulation under section 114 and only four substances for regulation under Senate bill 4358, section 115, the predecessor of CAA section 112.[239]

As adopted, CAA section 111(d) requires states to submit plans to the Administrator establishing ''emission standards'' for certain existing sources of air pollutants that were not otherwise regulated as criteria pollutants or hazardous air pollutants. This ensured that there would be ''no gaps in control activities pertaining to stationary source emissions that pose any significant danger to public health or welfare.'' [240]

The term ''emission standards,'' however, was not expressly defined in the 1970 CAA Amendments (save for purposes of citizen suit enforcement) even though the term was also used under the CAA's SIP provisions and CAA section 112.[241] That said, under the newly enacted ''ambient air quality and emission standards'' sections, Congress directed the EPA to provide states with information ''on air pollution control techniques,'' including data on ''available technology and alternative methods of prevention and control of air pollution'' and on ''alternative fuels, processes, and operating methods which will result in elimination or significant reduction of emissions.'' [242] Similarly, the Administrator would ''issue information on pollution control techniques for air pollutants'' in conjunction with establishing emission standards under CAA section 112. However, analogous text is absent from CAA section 111(d).

After the enactment of the 1970 CAA Amendments, the EPA proposed standards of performance for an ''initial list of five stationary source categories which contribute significantly to air pollution'' in August 1971.[243] The first category listed was for fossil-fuel fired steam generators, for which EPA proposed and promulgated standards for particulate matter, SO_2, and NO_X.[244]

Several years later, the EPA proposed its implementing regulations for CAA section 111(d).[245] These regulations were finalized in November 1975, and provided for the publication of emission guidelines.[246] The first emission guidelines were proposed in May 1976 and finalized in March 1977.[247]

Despite these first steps taken under CAA sections 111(b) and (d), Congress revisited the CAA in 1977 to address growing concerns with the nation's response to the 1973 oil embargo (noted above), to respond to new environmental problems such as stratospheric ozone depletion, and to resolve other issues associated with implementing the 1970 CAA Amendments.[248] Most notably, an increase in coal use as a result of the oil crisis meant that ''vigorous and effective control'' of air emissions was ''even more urgent.'' [249] Thus, to curb the projected surge in air emissions, Congress enacted several new provisions to the CAA. These new provisions include the prevention of significant deterioration (PSD) program, visibility protections, and requirements for nonattainment areas.[250]

Congress also made significant changes to CAA section 111. For example, Congress amended the definition of a standard of performance (including by requiring the consideration of ''nonair quality health and environmental impact and energy requirements''), authorized alternative (*e.g.,* work practice or design) standards in limited circumstances, provided states with authority to petition the Administrator for new or revised (and more stringent) standards, and imposed a strict regulatory schedule for establishing standards of performance for categories of major stationary sources that had not yet been listed.[251]

---

[235] H.R. 17255, 91st Cong. § 5 (1970).

[236] S. 4358, 91st Cong. § 6 (1970) (emphasis added). The breadth of the Senate bill is further emphasized in the conference report, which explains that a standard of performance ''refers to the degree of emission control which can be achieved through process changes, operation changes, direct emission control, or other methods'' and also includes ''other means of preventing or controlling air pollution.'' S. Rep. No. 91–1196, at 15–16 (Sept. 17, 1970).

[237] S. 4358, 91st Cong. § 6 (1970).

[238] The House bill did not provide for the direct regulation of existing sources.

[239] *See* S. Rep. No. 91–1196, at 18 and 20 (Sept. 17, 1970).

[240] S. Rep. No. 91–1196, at 20 (Sept. 17, 1970) (discussing the relationship between sections 114 (addressing emission standards for ''selected air pollution agents'') and 115 (addressing hazardous air pollutants) of the Senate bill).

[241] *See* ''Clean Air Act Amendments of 1970,'' § 12, 84 Stat. at 1706.

[242] ''Clean Air Act Amendments of 1970,'' § 4, 84 Stat. at 1679.

[243] ''Standards of Performance for New Stationary Sources: Proposed Standards for Five Categories,'' 36 FR 15704 (Aug. 17, 1971). *See* ''Clean Air Act Amendments of 1970,'' § 4, 84 Stat. at 1684 (requiring the Administrator to publish a list of categories of stationary sources within 90 days of the enactment of the 1970 CAA Amendments).

[244] 36 FR at 15704–706; and ''Standards of Performance for New Stationary Sources,'' 36 FR 24876, 24879 (Dec. 23, 1971).

[245] *See* ''State Plans for the Control of Existing Facilities,'' 39 FR 36102 (Oct. 7, 1974).

[246] *See* ''State Plans for the Control of Certain Pollutants from Existing Facilities,'' 40 FR 53340 (Nov. 17, 1975).

[247] *See* ''Phosphate Fertilizer Plants; Draft Guideline Document; Availability,'' 41 FR 19585 (May 12, 1976); and ''Phosphate Fertilizer Plants; Final Guideline Document Availability,'' 42 FR 12022 (Mar. 1, 1977).

[248] For example, Congress recognized that many air pollutants had not been regulated despite ''mounting evidence'' that these pollutants ''are associated with serious health hazards''. H.R. Rep. No. 94–1175, 22 (May, 15, 1976). Because EPA ''failed to promulgate regulations to institute adequate control measures,'' Congress ordered EPA to regulate four specific pollutants that had ''been found to be cancer-causing or cancer-promoting''. *Id.* at 23. This directive, reflected in CAA section 122, specifically added radioactive pollutants, cadmium, arsenic, and polycyclic organic matter ''under the various provisions of the Clean Air Act and allows their regulation as criteria pollutants under ambient air quality standards, as hazardous air pollutants, or under new source performance standards, as appropriate.'' H.R. Conf. Rep. No. 95–564, 142 (Aug. 3, 1977), 1977 CAA Legis. Hist. at 522. At the same time, Congress made sure that these commands would have no effect on the Administrator's discretion to address ''any substance (whether or not enumerated [under CAA section 122(a))'' under CAA sections 108, 112, or 111. 42 U.S.C. 7422(b).

[249] *See* Statement of EPA Administrator Costle, S. Hearings on S. 272, S. 273, S. 977, and S. 1469 (Apr. 5, 7, May 25, June 24 and 30, 1977), 1977 CAA Legis. Hist. at 3532.

[250] *See* ''Clean Air Act Amendments of 1977,'' Pub. L. 95–95, §§ 127–129, 91 Stat. 685 (Aug. 7, 1977).

[251] ''Clean Air Act Amendments of 1977,'' § 109, 91 Stat. at 697.

The 1977 definition for a standard of performance required ''all new sources to meet emission standards based on the reductions achievable through the use of the 'best technological system of continuous emission reduction.' ''[252] For fossil-fuel fired stationary sources, Congress further required a percentage reduction in emissions from the use of fuels.[253] Together, this was designed to ''force new sources to burn high-sulfur fuel thus freeing low-sulfur fuel for use in existing sources where it is harder to control emissions and where low-sulfur fuel is needed for compliance.''[254]

Congress also clarified that with respect to CAA section 111(d), standards of performance (now applicable in lieu of emission standards) ''would be based on the best available means (not necessarily technological)''.[255] This was intended to distinguish existing source standards from new source standards, for which ''the requirement for [the BSER] has been more narrowly redefined as best technological system of continuous emission reduction.''[256] Additionally, Congress clarified that states could consider ''the remaining useful life'' of a source when applying a standard of performance to a particular existing source.[257]

In the twenty years since the 1970 CAA Amendments and in spite of the refinements of the 1977 CAA Amendments, ''many of the Nation's most important air pollution problems [had] failed to improve or [had] grown more serious.''[258] Indeed, in 1989, President George Bush said that '' 'progress has not come quickly enough and much remains to be done.' ''[259] This time, with the 1990 CAA Amendments, Congress substantially overhauled the CAA. In particular, Congress again added to the NAAQS program, completely revised CAA section 112, added a new title to target existing fossil fuel-fired stationary sources and address growing concerns with acid rain, imported an operating permit modeled off the Clean Water Act, and established a phase out of certain ozone depleting substances.

All told, however, there was minimal debate on changes to CAA section 111. In fact, the only discussion centered on the repeal of the percentage reduction requirement, which became seen as unduly restrictive. Accordingly, Congress reverted the definition of ''standard of performance'' to the definition agreed to in the 1970 CAA Amendments, but retained the requirement to consider nonair quality environmental impacts and energy requirements added in 1977.[260] However, the repeal would only apply so long as the SO_2 cap under CAA section 403(e) of the newly established acid rain program remained in effect.[261] Lastly, Congress instructed the EPA to revise its new source performance standards for SO_2 emissions from fossil fuel-fired power plants but required that the revised emission rate be no less stringent than before.[262]

I. Statutory and Regulatory Requirements

Clean Air Act section 111, which Congress enacted as part of the 1970 Clean Air Act Amendments, establishes mechanisms for controlling emissions of air pollutants from stationary sources. This provision 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.''[263] The EPA has listed more than 60 stationary source categories under this provision.[264] Once the EPA lists a source category, the EPA must, under CAA section 111(b)(1)(B), establish ''standards of performance'' for emissions of air pollutants from new sources in the source categories.[265] These standards are known as new source performance standards (NSPS), and they are national requirements that apply directly to the sources subject to them.

When the EPA establishes NSPS for new sources in a particular source category, the EPA is also required, under CAA section 111(d)(1), to prescribe regulations for states to submit plans regulating existing sources in that source category for any air pollutant that, in general, is not regulated under the CAA section 109 requirements for the NAAQS or regulated under the CAA section 112 requirements for HAP. CAA section 111(d)'s mechanism for regulating existing sources differs from the one that CAA section 111(b) provides for new sources because CAA section 111(d) contemplates states submitting plans that establish ''standards of performance'' for the affected sources and that contain other measures to implement and enforce those standards.

''Standards of performance'' are defined under CAA section 111(a)(1) as standards for emissions that reflect the emission limitation achievable from the ''best system of emission reduction,'' considering costs and other factors, that ''the Administrator determines has been adequately demonstrated.'' CAA section 111(d)(1) grants states the authority, in applying a standard of performance to a particular source, to take into account the source's remaining useful life or other factors.

Under CAA section 111(d), a state must submit its plan to the EPA for approval, and the EPA must approve the state plan if it is ''satisfactory.''[266] If a state does not submit a plan, or if the EPA does not approve a state's plan, then the EPA must establish a plan for that state.[267] Once a state receives the EPA's approval of its plan, the provisions in the plan become federally enforceable against the entity responsible for noncompliance, in the same manner as the provisions of an approved SIP under the Act.

Section 302(d) of the CAA defines the term ''state'' to include the Commonwealth of Puerto Rico, the Virgin Islands, Guam, American Samoa and the Commonwealth of the Northern Mariana Islands. While 40 CFR part 60 contains a separate definition of ''state'' at section 60.2, this definition expands on, rather than narrows, the definition in section 302(d) of the CAA. The introductory language to 40 CFR 60.2 provides: ''The terms in this part are defined in the Act or in this section as follows.'' Section 60.2 defines ''State'' as

[252] H.R. Rep. No. 95–294, at 192 (May 12, 1977). Congress separately defined ''technological system of continuous emission reduction'' as ''(A) a technological process for production or operation by any source which is inherently low-polluting or nonpolluting, or (B) technological system for continuous reduction of the pollution generated by a source before such pollution is emitted into the ambient air, including precombustion cleaning or treatment of fuels.'' ''Clean Air Act Amendments of 1977,'' § 109, 91 Stat. at 700; *see also* 42 U.S.C. 7411(a)(7).

[253] ''Clean Air Act Amendments of 1977,'' § 109, 91 Stat. at 700.

[254] ''New Stationary Sources Performance Standards; Electric Utility Steam Generating Units,'' 44 FR 33580, 33581–82 (June 11, 1979).

[255] H.R. Rep. No. 95–294, at 195 (May 12, 1977).

[256] Sen. Muskie, S. Consideration of the H.R. Conf. Rep. No. 95–564 (Aug. 4, 1977), 1977 CAA Legis. Hist. at 353.

[257] This concept was already reflected in the EPA's CAA section 111(d) implementing regulations under 40 CFR 60.24(f). *See* 40 FR 53340, 53347 (Nov. 17, 1975).

[258] H.R. Rep. No. 101–490, at 144 (May 17, 1990).

[259] H.R. Rep. No. 101–490, at 144 (May 17, 1990).

[260] Congress also updated the regulatory schedule that was added in the 1977 CAA Amendments to reflect the newly enacted 1990 CAA Amendments. *See* ''Clean Air Act Amendments of 1990,'' § 108, 104 Stat. 2467.

[261] ''Clean Air Act Amendments of 1990,'' § 403, 104 Stat. at 2631.

[262] ''Clean Air Act Amendments of 1990,'' § 301, 104 Stat. at 2631.

[263] CAA section 111(b)(1)(A).

[264] *See* 40 CFR 60 subparts Cb—OOOO.

[265] CAA section 111(b)(1)(B), 111(a)(1).

[266] CAA section 111(d)(2)(A).

[267] CAA section 111(d)(2)(A).

''all non-Federal authorities, including local agencies, interstate associations, and State-wide programs that have been delegated authority to implement: (1) The provisions of this part and/or (2) the permit program established under part 70 of this chapter. The term State shall have its conventional meaning where clear from the context.'' The EPA believes that the last sentence refers to the conventional meaning of ''state'' under the CAA. Thus, the EPA believes the term ''state'' as used in the emission guidelines is most reasonably interpreted as including the meaning ascribed to that term in section 302(d) of the CAA, which expressly includes U.S. territories.

Section 301(d)(A) of the CAA recognizes that the American Indian tribes are sovereign Nations and authorizes the EPA to ''treat tribes as States under this Act''. The Tribal Authority Rule (63 FR 7254, February 12, 1998) identifies that EPA will treat tribes in a manner similar to states for all of the CAA provisions with the exception of, among other things, specific plan submittal and implementation deadlines under the CAA. As a result, though they operate as part of the interconnected system of electricity production and distribution, affected EGUs located in Indian country would not be encompassed within a state's CAA section 111(d) plan. Instead, an Indian tribe with one or more affected EGUs located in its area of Indian country [268] will have the opportunity, but not the obligation, to apply for eligibility to develop and implement a CAA section 111(d) plan. The Indian tribe would need to be approved by the EPA as eligible to develop and implement a CAA section 111(d) plan following the procedure set forth in 40 CFR part 49. Once a tribe is approved as eligible for that purpose, it would be treated in the same manner as a state, and references in the emission guidelines to states would refer equally to the tribe. The EPA notes that, while tribes have the opportunity to apply for eligibility to administer CAA programs, they are not required to do so. Further, the EPA has established procedures in 40 CFR part 49 (see particularly 40 CFR 49.7(c)) that permit eligible tribes to request approval of reasonably severable partial program elements. Those procedures are applicable here.

In these final emission guidelines, the term ''state'' encompasses the 50 states and the District of Columbia, U.S. territories, and any Indian tribe that has been approved by the EPA pursuant to 40 CFR 49.9 as to develop and implement a CAA section 111(d) plan.

The EPA issued regulations implementing CAA section 111(d) in 1975,[269] and has revised them in the years since.[270] (We refer to the regulations generally as the implementing regulations.) These regulations provide that, in promulgating requirements for sources under CAA section 111(d), the EPA first develops regulations known as ''emission guidelines,'' which establish binding requirements that states must address when they develop their plans.[271] The implementing regulations also establish timetables for state and EPA action: States must submit state plans within 9 months of the EPA's issuance of the guidelines,[272] and the EPA must take final action on the state plans within 4 months of the due date for those plans,[273] although the EPA has authority to extend those deadlines.[274] In this rulemaking, the EPA is following the requirements of the implementing regulations, and is not re-opening them, except that the EPA is extending the timetables, as described below.

Over the last forty years, under CAA section 111(d), the agency has regulated four pollutants from five source categories (*i.e.,* sulfuric acid plants (acid mist), phosphate fertilizer plants (fluorides), primary aluminum plants (fluorides), Kraft pulp plants (total reduced sulfur), and municipal solid waste landfills (landfill gases)).[275] In addition, the agency has regulated additional pollutants under CAA section 111(d) in conjunction with CAA section 129.[276] The agency has not previously regulated CO_2 or any other GHGs under CAA section 111(d).

The EPA's previous CAA section 111(d) actions were necessarily geared toward the pollutants and industries regulated. Similarly, in this rulemaking, in defining CAA section 111(d) emission guidelines for the states and determining the BSER, the EPA believes that taking into account the particular characteristics of carbon pollution, the interconnected nature of the power sector and the manner in which EGUs are currently operated is warranted. Specifically, the operators themselves treat increments of generation as interchangeable between and among sources in a way that creates options for relying on varying utilization levels, lowering carbon generation, and reducing demand as components of the overall method for reducing CO_2 emissions. Doing so results in a broader, forward-thinking approach to the design of programs to yield critical CO_2 reductions that improve the overall power system by lowering the carbon intensity of power generation, while offering continued reliability and cost-effectiveness. These opportunities exist in the utility power sector in ways that were not relevant or available for other industries for which the EPA has established CAA section 111(d) emission guidelines.[277]

In this action, the EPA is promulgating emission guidelines for states to follow in developing their CAA section 111(d) plans to reduce emissions of CO_2 from the utility power sector.

J. Clean Power Plan Proposal and Supplemental Proposal

On June 18, 2014, the EPA proposed emission guidelines for states to follow in developing plans to address GHG emissions from existing fossil fuel-fired electric generating units (EGUs). Specifically, the EPA proposed rate-based goals for CO_2 emissions for each

[268] The EPA is aware of at least four affected sources located in Indian Country: Two on Navajo lands—the Navajo Generating Station and the Four Corners Generating Station; one on Ute lands—the Bonanza Generating Station; and one on Fort Mojave lands, the South Point Energy Center. The affected EGUs at the first three plants are coal-fired EGUs. The fourth affected EGU is an NGCC facility.

[269] ''State Plans for the Control of Certain Pollutants from Existing Facilities,'' 40 FR 53340 (Nov. 17, 1975).

[270] The most recent amendment was in 77 FR 9304 (Feb. 16, 2012).

[271] 40 CFR 60.22. In the 1975 rulemaking, the EPA explained that it used the term ''emission guidelines''—instead of emissions limitations—to make clear that guidelines would not be binding requirements applicable to the sources, but instead are ''criteria for judging the adequacy of State plans.'' 40 FR at 53343.

[272] 40 CFR 60.23(a)(1).

[273] 40 CFR 60.27(b).

[274] *See* 40 CFR 60.27(a).

[275] *See* ''Phosphate Fertilizer Plants; Final Guideline Document Availability,'' 42 FR 12022 (Mar. 1, 1977); ''Standards of Performance for New Stationary Sources; Emission Guideline for Sulfuric Acid Mist,'' 42 FR 55796 (Oct. 18, 1977); ''Kraft Pulp Mills, Notice of Availability of Final Guideline Document,'' 44 FR 29828 (May 22, 1979); ''Primary Aluminum Plants; Availability of Final Guideline Document,'' 45 FR 26294 (Apr. 17, 1980); ''Standards of Performance for New Stationary Sources and Guidelines for Control of Existing Sources: Municipal Solid Waste Landfills, Final Rule,'' 61 FR 9905 (Mar. 12, 1996).

[276] *See, e.g.,* ''Standards of Performance for New Stationary Sources and Emission Guidelines for Existing Sources: Sewage Sludge Incineration Units, Final Rule,'' 76 FR 15372 (Mar. 21, 2011).

[277] *See* ''Phosphate Fertilizer Plants; Final Guideline Document Availability,'' 42 FR 12022 (Mar. 1, 1977); ''Standards of Performance for New Stationary Sources; Emission Guideline for Sulfuric Acid Mist,'' 42 FR 55796 (Oct. 18, 1977); ''Kraft Pulp Mills, Notice of Availability of Final Guideline Document,'' 44 FR 29828 (May 22, 1979); ''Primary Aluminum Plants; Availability of Final Guideline Document,'' 45 FR 26294 (Apr. 17, 1980); ''Standards of Performance for New Stationary Sources and Guidelines for Control of Existing Sources: Municipal Solid Waste Landfills, Final Rule,'' 61 FR 9905 (Mar. 12, 1996).

state with existing fossil fuel-fired EGUs, as well as guidelines for plans to achieve those goals. On November 4, 2014, the EPA published a supplemental proposal that proposed emission rate-based goals for CO_2 emissions for U.S. territories and areas of Indian country with existing fossil fuel-fired EGUs. In the supplemental proposal, the EPA also solicited comment on authorizing jurisdictions (including any states, territories and areas of Indian country) without existing fossil fuel-fired EGUs subject to the proposed emission guidelines to partner with jurisdictions (including any states) that do have existing fossil fuel-fired EGUs subject to the proposed emission guidelines in developing multi-jurisdictional plans. The EPA also solicited comment on the treatment of RE, demand-side EE and other new low- or zero-emitting electricity generation across international boundaries in a state plan.

The EPA also issued two documents after the June 18, 2014 proposal. On October 30, 2014, the EPA published a NODA in which the agency provided additional information on several topics raised by stakeholders and solicited comment on the information presented. This action covered three topic areas: 1) the emission reduction compliance trajectories created by the interim goal for 2020 to 2029, 2) certain aspects of the building block methodology, and 3) the way state-specific CO_2 goals are calculated.

In a separate action, the EPA published a document regarding potential methods for determining the mass that is equivalent to an emission rate-based CO_2 goal (79 FR 67406; November 13, 2014). With the action, the EPA also made available, in the docket for this rulemaking, a TSD that provided two examples of how a state, U.S. territory or tribe could translate a rate-based CO_2 goal to total metric tons of CO_2 (a mass-based equivalent).

K. Stakeholder Outreach and Consultations

Following the direction in the Presidential Memorandum to the Administrator (June 25, 2013),[278] the EPA engaged in extensive and vigorous outreach to stakeholders and the general public at every stage of development of this rule. Our outreach has included direct engagement with the energy and environment officials in states, tribes, and a full range of stakeholders including leaders in the utility power sector, labor leaders, non-governmental organizations, other federal agencies, other experts, community groups and members of the public. The EPA participated in more than 300 meetings before the rule was proposed and more than 300 after the proposal.

Throughout the rulemaking process, the agency has encouraged, organized, and participated in hundreds of meetings about CAA section 111(d) and reducing carbon pollution from existing power plants. The agency's outreach prior to proposal, as well as during the public comment period, was designed to solicit policy ideas,[279] concerns, and technical information. The agency received 4.3 million comments about all aspects of the proposed rule and thousands of people participated in the agency's public hearings, webinars, listening sessions,[280] teleconferences and meetings held all across the country.

Our engagement has brought together a variety of states and stakeholders to discuss a wide range of issues related to the utility power sector and the development of emission guidelines under CAA section 111(d). The meetings were attended by the EPA Regional Administrators, other senior managers and staff who have been instrumental in the development of the rule and will play key roles in developing and implementing it.

This outreach process has produced a wealth of information which has informed this rule significantly. The pre-proposal outreach efforts far exceeded what is required of the agency in the normal course of a rulemaking process, and the EPA expects that the dialogue with states and stakeholders will continue after the rule is finalized. The EPA recognizes the importance of working with all stakeholders, and in particular with the states, to ensure a clear and common understanding of the role the states will play in addressing carbon pollution from power plants. We firmly believe that our outreach has resulted in a more workable rule that will achieve the statutory goals and has enhanced the likelihood of timely and successful achievement of the carbon reduction goals, given the critical importance and urgency of the concrete action.

The EPA has given stakeholder comments careful consideration and, as a result, this final rule includes features that are responsive to many stakeholder concerns.

1. Public Hearings

More than 2,700 people attended the public hearings sessions held in Atlanta, Denver, Pittsburgh, and Washington, DC. More than 1,300 people spoke at the public hearings. Additionally, about 100 people attended the public hearing held in Phoenix, Arizona, on the November 4, 2014 supplemental proposal. Speakers at the public hearings included Members of Congress, other public officials, industry representatives, faith-based organizations, unions, environmental groups, community groups, students, public health groups, energy groups, academia and concerned citizens.

Participants shared a range of perspectives. Many were concerned with the impacts of climate change on their health and on future generations, others were worried about the impact of regulations on the economy. Their support for the agency's efforts varied.

2. State Officials

Since fall 2013, the agency has provided multiple opportunities for the states to inform this rulemaking. Administrator McCarthy has engaged with governors from states with a variety of interests in the rulemaking. Other senior agency officials have engaged with every branch and major agency of state government—including state legislators, attorneys general, state energy, environment, and utility officials, and governors' staff.

On several occasions, state environmental commissioners met with senior agency officials to provide comments on the Clean Power Plan. The EPA organized, encouraged and attended meetings with states to discuss multi-state planning efforts. States have come together with several collaborative groups to discuss ways to work together to make the Clean Power Plan more affordable. The EPA has participated in and supported the states in these discussions. Because of the interconnectedness of the power sector, and the fact that electricity generated at power plants crosses state lines; states, utilities and ratepayers may benefit from states working together to implement the requirements of this rulemaking. The meetings provided state leaders, including governors, environmental commissioners, energy officers, public utility commissioners, and air directors, opportunities to engage with the EPA officials. In addition, the states

[278] Presidential Memorandum—Power Sector Carbon Pollution Standards, June 25, 2013. *http://www.whitehouse.gov/the-press-office/2013/06/25/presidential-memorandum-power-sector-carbon-pollution-standards.*

[279] The EPA received more than 2,000 emails offering input into the development of these guidelines through email and a Web-based form. These emails and other materials provided to the EPA are posted on line as part of a non-regulatory docket, EPA Docket ID No. EPA–HQ–OAR–2014–0020, at *www.regulations.gov.*

[280] Summaries of the 11 public listening sessions in 2013 are available at *www.regulations.gov* at EPA Docket ID No. EPA–HQ–OAR–2014–0020.

submitted public comments from several agencies within each state. The wealth of comments and input from states was important in developing the final rulemaking.

Agency officials listened to ideas, concerns and details from states, including from states with a wide range of experience in reducing carbon pollution from power plants. The EPA reached out to all 50 states to engage with both environmental and energy departments at all levels of government. As an example, a three-part webinar series in June/July 2014 for the states and tribes offered an interactive format for technical staff at the EPA and in the states/tribes to exchange ideas and ask clarifying question. The webinars were then posted online so other stakeholders could view them. A few weeks after the postings, the EPA organized follow-up conference calls with stakeholder groups. Also, the EPA hosted scores of technical meetings between states and the EPA in the weeks and months after the rule was proposed.

Additionally, the EPA organized ''hub'' calls; these teleconferences brought all of the states in a given EPA region together to discuss technical and interstate aspects of the proposal. These exchanges helped provide the stakeholders with the information they needed to comment on the proposal effectively. The EPA also held a series of webinars with state environmental associations and their members on a series of technical issues.

The agency has collected policy papers and comment letters from states with overarching energy goals and technical details on the states' utility power sector. EPA leadership and staff also participated in webinars and meetings with state and tribal officials hosted by collaborative groups and trade associations. After the comment period closed, and based on our meetings over the last year, as well as written comments on the proposal and NODA, the EPA analyzed information about data errors that needed to be addressed for the final rule. In February and March 2015, we reached out to particular states to clarify ambiguous or unclear information that was submitted to the EPA related to NEEDS and eGRID data. The EPA contacted particular states to clarify the technical comments or concerns to ensure that any changes we make are accurate and appropriate.

To help prepare for implementation of this rule, the agency initiated several outreach activities to assist with state planning efforts. The agency participated in meetings organized by the National Association of State Energy Officials (NASEO), the National Association of Regulatory Utility Commissioners (NARUC), and the National Association of Clean Air Agencies (NACAA) (the ''3N'' groups). Meeting participants discussed issues related to EE and RE.

To help state officials prepare for the planning process that will take place in the states, the EPA presented a webinar on February 24, 2015. This webinar provided an update on training plans and further connection with states in the implementation process. Forty-nine states, the District of Columbia, and 14 tribes were represented at this webinar. The EPA is developing a state plan electronic collection system to receive, track, and store state submittals of plans and reports. The EPA plans to use an integrated project team to solicit stakeholder input on the system during development. The team membership, including state representatives, will bring together the business and technology skills required to construct a successful product and promote transparency in the EPA's implementation of the rule.

To help identify training needs for the final Clean Power Plan, the agency reached out to a number of state and local organizations such as the Central State Air Resources Agencies and other such regional air agencies. The EPA's outreach on training has included sharing the plans with the states and incorporating changes to the training topics based on the states' needs. The EPA training plan includes a wide variety of topics such as basic training on the electric power sector as well as specific pollution control strategies to reduce carbon emissions from power plants. In particular, the states requested training on how to use programs such as combined heat and power, EE and RE to reduce carbon emissions. The EPA will continue to work with states to tailor training activities to their needs.

The agency has engaged, and will continue to engage with states, territories, Washington, DC, and tribes after the rulemaking process and throughout implementation.

3. Tribal Officials

The EPA conducted significant outreach to and consultation with tribes. Tribes are not required to, but may, develop or adopt Clean Air Act programs. The EPA is aware of four facilities with affected EGUs located in Indian country: the South Point Energy Center, in Fort Mojave Indian country, geographically located within Arizona; the Navajo Generating Station, in Navajo Indian country, geographically located within Arizona; the Four Corners Power Plant, in Navajo Indian country, geographically located within New Mexico; and the Bonanza Power Plant, in Ute Indian country, geographically located within Utah. The EPA offered consultation to the leaders of the tribes on whose lands these facilities are located as well as all of the federally recognized tribes to ensure that they had the opportunity to have meaningful and timely input into this rule. Section III (''Stakeholder Outreach and Conclusions'') of the June 18, 2014 proposal documents the EPA's extensive outreach efforts to tribal officials prior to that proposal, including an informational webinar, outreach meeting, teleconferences with tribal officials and the National Tribal Air Association (NTAA), and letters offering consultation. Additional outreach to tribal officials conducted by the EPA prior to the November 4, 2014 supplemental proposal is discussed in Section II.D (''Additional Outreach and Consultation'') of the supplemental proposal. The additional outreach for the supplemental proposal included consultations with all three tribes that have affected EGUs on their lands, as well as several other tribes that requested consultation, and also additional teleconferences with the NTAA.

After issuing the supplemental proposal, the EPA offered an additional consultation to the leaders of all federally recognized tribes. The EPA held an informational meeting open to all tribes and also held consultations with the Navajo Nation, Fort McDowell Yavapai Nation, Fort Mojave Tribe, Ak-Chin Indian Community, and Hope Tribe on November 18, 2014. The EPA held a consultation with the Ute Tribe of the Uintah and Ouray Reservation on December 16, 2014, and a consultation with the Gila River Indian Community on January 15, 2015. The EPA held a public hearing on the supplemental proposal on November 19, 2014, in Phoenix, Arizona. On April 28, 2015, the EPA held an additional consultation with the Navajo Nation.

Tribes were interested in the impact of this rule on other ongoing regulatory actions at the affected EGUs, such as permitting or requirements for the best available retrofit technology (BART). Tribes also noted that it was important to allow RE projects on tribal lands to contribute toward meeting state goals. Some tribes indicated an interest in being involved in the development of implementation plans for areas of Indian country. Additional detail regarding the EPA's outreach to tribes and comments and recommendations from tribes can be found in Section X.F of this preamble.

4. U.S. Territories

The EPA has met with individual U.S. territories and affected EGUs in U.S. territories during the rulemaking process. On July 22, 2014, the EPA met with representatives from the Puerto Rico Environmental Quality Board, the Puerto Rico Electric Power Authority, the Governor's Office, and the Office of Energy, Puerto Rico. On September 8, 2014, the EPA held a meeting with representatives from the Guam Environmental Protection Agency (GEPA) and the Guam Power Authority and, on February 18, 2015, the EPA met again with representatives from GEPA.

5. Industry Representatives

Agency officials have engaged with industry leaders and representatives from trade associations in many one-on-one and national meetings. Many meetings occurred at the EPA headquarters and in the EPA's Regional Offices and some were sponsored by stakeholder groups. Because the focus of the rule is on the utility power sector, many of the meetings with industry have been with utilities and industry representatives directly related to the utility power sector. The agency has also met with energy industries such as coal and natural gas interests, as well as companies that offer new technology to prevent or reduce carbon pollution, including companies that have expertise in RE and EE. Other meetings have been held with representatives of energy intensive industries, such as the iron and steel and aluminum industries, to help understand the issues related to large industrial users of electricity.

6. Electric Utility Representatives

Agency officials participated in many meetings with utilities and their associations to discuss all aspects of the proposed guidelines. We have met with all types of companies that produce electricity, including private utilities or investor owned utilities. Public utilities and cooperative utilities were also part of in-depth conversations about CAA section 111(d) with EPA officials.

The conversations included meetings with the EPA headquarters and regional offices. State officials were included in many of the meetings. Meetings with utility associations and groups of utilities were held with key EPA officials. The meetings covered technical, policy and legal topics of interest and utilities expressed a wide variety of support and concerns about CAA section 111(d).

7. Electricity Grid Operators

The EPA had a number of conversations with the ISOs and RTOs to discuss the rule and issues related to grid operations and reliability. EPA staff met with the ISO/RTO Council on several occasions to collect their ideas. The EPA regional offices also met with the ISOs and RTOs in their regions. System operators have offered suggestions in using regional approaches to implement CAA section 111(d) while maintaining reliable, affordable electricity.

8. Representatives from Community and Non-governmental Organizations

Agency officials engaged with community groups representing vulnerable communities, and faith-based groups, among others, during the outreach effort. In response to a request from communities, the EPA held a day-long training on the Clean Power Plan on October 30, 2014, in Washington DC At this meeting, the EPA met with a number of environmental groups to provide information on how the agency plans on reducing carbon pollution from existing power plants using CAA section 111(d).

Many environmental organizations discussed the need for reducing carbon pollution. Meetings were technical, policy and legal in nature and many groups discussed specific state policies that are already in place to reduce carbon pollution in the states.

A number of organizations representing religious groups have reached out to the EPA on several occasions to discuss their concerns and ideas regarding this rule. Many members of faith communities attended the four public hearings.

Public health groups discussed the need for protection of children's health from harmful air pollution. Doctors and health care providers discussed the link between reducing carbon pollution and air pollution and public health. Consumer groups representing advocates for low income electricity customers discussed the need for affordable electricity. They talked about reducing electricity prices for consumers through EE and low-cost carbon reductions.

In winter/spring 2015, EPA continued to offer webinars and teleconferences for community groups on the rulemaking.

9. Environmental Justice Organizations

Agency officials engaged with environmental justice groups representing communities of color, low-income communities and others during the outreach effort. Agency officials also engaged with the EPA's National Environmental Justice Advisory Council (NEJAC) members in September 2013. The NEJAC is composed of stakeholders, including environmental justice leaders and other leaders from state and local government and the private sector. Additionally, the agency conducted a community call on February 26, 2015, and on February 27, 2015, the EPA conducted a follow up webinar for participants in an October 30, 2014 training session. The EPA also held a webinar for communities on the Clean Air Act (CAA) and section 111(d) of the CAA on April 2, 2015. The agency, in partnership with FERC and DOE, held two additional webinars for communities on the electricity grid and on energy markets on June 11, 2015, and July 9, 2015.

During the EPA's extensive outreach conducted before and after proposal, the EPA has heard a variety of issues raised by environmental justice communities. Communities expressed the desire for the agency to conduct an environmental justice (EJ) analysis and to require that states in the development of their state plans conduct one as well. Additionally, they asked that the agency require that states engage with communities in the development of their state plans and that the agency conduct meaningful involvement with communities, throughout the whole rulemaking process, including the implementation phase. Furthermore, communities stressed the importance of low-income and communities of color receiving the benefits of this rulemaking and being protected from being adversely impacted by this rulemaking.

The purpose of this rule is to substantially reduce emissions of CO_2, a key contributor to climate change, which adversely and disproportionately affects vulnerable and disadvantaged communities in the U.S. and around the world. In addition, the rule will result in substantial reductions of conventional air pollutants, providing immediate public health benefits to the communities where the facilities are located and for many miles around. The EPA is committed to ensuring that all Americans benefit from the public health and other benefits that this rule will bring. Further discussion of the impacts of this rule on vulnerable communities and actions that the EPA is taking to address concerns cited by communities is available in Sections IX and XII.J of this preamble.

10. Labor

Senior agency officials met with a number of labor union representatives about reducing carbon pollution using CAA section 111(d). Those unions included: The United Mine Workers of America; the Sheet Metal, Air, Rail and Transportation Union (SMART); the

International Brotherhood of Boilermakers, Iron Ship Builders, Blacksmiths, Forgers and Helpers (IBB); United Association of Journeymen and Apprentices of the Plumbing and Pipe Fitting Industry of the United States and Canada; the International Brotherhood of Electrical Workers (IBEW); and the Utility Workers Union of America. In addition, agency leaders met with the Presidents of several unions and the President of the American Federation of Labor-Congress of Industrial Organizations (AFL–CIO) at the AFL–CIO headquarters.

EPA officials attended meetings sponsored by labor unions to give presentations and engage in discussions about reducing carbon pollution using CAA section 111(d). These included meetings sponsored by the IBB and the IBEW.

11. Other Federal Agencies and Independent Agencies

Throughout the development of the rulemaking, the EPA consulted with other federal agencies with relevant expertise. For example, the EPA met with managers from the U.S. Department of Agriculture's (USDA's) Rural Utility Service to discuss the rule and potential effects on affected EGUs in rural areas and how USDA programs could interact with affected EGUs during rule implementation.

The U.S. Department of Energy (DOE) was a frequent source of expertise on the proposed and final rule. EPA management and staff had numerous meetings with management and staff at DOE on a range of topics, including the effectiveness and costs of energy generation technologies, and EE.

DOE provided technical assistance relating to RE and demand-side EE, including RE and demand-side EE cost and performance data and, for RE, information on the feasibility of deploying and reliably integrating increased RE generation. Further, EPA and DOE staff discussed emission measurement and verification (EM&V) strategies.

The EPA also consulted with DOE on electric reliability issues. EPA staff and managers met and spoke with DOE staff and managers throughout the development of the proposed and final rules on topic related to electric system reliability.

EPA officials worked closely with DOE and Federal Energy Regulatory Commission (FERC) officials to ensure, to the greatest extent possible, that actions taken by states and affected EGUs to comply with the final rule mitigate potential electric system reliability issues. Senior EPA officials met with each of the FERC Commissioners and EPA staff had frequent contact with FERC staff throughout the development the rule. FERC held four technical conferences to discuss implications of compliance approaches to the rule for electric reliability. EPA staff attended the four conferences and EPA leadership spoke at all of them. The EPA, DOE, and FERC will continue to work together to ensure electric grid reliability in the development and implementation of state plans.

L. Comments on the Proposal

The Administrator signed the proposed emission guidelines on June 2, 2014, and, on the same day, the EPA made this version available to the public at *http://www.epa.gov/cleanpowerplan/*. The 120-day public comment period on the proposal began on June 18, 2014, the day of publication of the proposal in the **Federal Register**. On September 18, 2014, in response to requests from stakeholders, the EPA extended the comment period by 45 days, to December 1, 2014, giving stakeholders over 165 days to review and comment upon the proposal. Stakeholders also had the opportunity to comment on the NODA, as well as the **Federal Register** document and TSD regarding potential methods for determining the mass that is equivalent to an emission rate-based CO_2 goal, through December 1, 2014. The EPA offered a separate 45-day comment period for the November 4, 2014 supplemental proposal, and that comment period closed on December 19, 2014.

The EPA received more than 4.2 million comments on the proposed carbon pollution emission guidelines from a range of stakeholders that included, including state environmental and energy officials, local government officials, tribal officials, public utility commissioners, system operators, utilities, public interest advocates, and members of the public. The agency received comments on many aspects of the proposal and many suggestions for changes that would address issues of concern.

III. Rule Requirements and Legal Basis

A. Summary of Rule Requirements

The EPA is establishing emission guidelines for states to use in developing plans to address GHG emissions from existing fossil fuel-fired electric generating units. The emission guidelines are based on the EPA's determination of the ''best system of emission reduction . . . adequately demonstrated'' (BSER) and include source category-specific CO_2 emission performance rates, state-specific goals, requirements for state plan components, and requirements for the process and timing for state plan submittal and compliance.

Under CAA section 111(d), the states must establish standards of performance that reflect the degree of emission limitation achievable through the application of the ''best system of emission reduction'' that, taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements, the Administrator determines has been adequately demonstrated.

The EPA has determined that the BSER is the combination of emission rate improvements and limitations on overall emissions at affected EGUs that can be accomplished through the following three sets of measures or building blocks:

1. Improving heat rate at affected coal-fired steam EGUs.
2. Substituting increased generation from lower-emitting existing natural gas combined cycle units for generation from higher-emitting affected steam generating units.
3. Substituting increased generation from new zero-emitting RE generating capacity for generation from affected fossil fuel-fired generating units.

Consistent with CAA section 111(d) and other rules promulgated under this section, the EPA is taking a traditional, performance-based approach to establishing emission guidelines for affected sources and applying the BSER to two source subcategories of existing fossil fuel-fired EGUs—fossil fuel-fired electric utility steam generating units and stationary combustion turbines. The EPA is finalizing source subcategory-specific emission performance rates that reflect the EPA's application of the BSER. For fossil fuel-fired steam generating units, we are finalizing a performance rate of 1,305 lb CO_2/MWh. For stationary combustion turbines, we are finalizing a performance rate of 771 lb CO_2/MWh. The EPA has also translated the source subcategory-specific CO_2 emission performance rates into equivalent statewide rate-based and mass-based CO_2 goals and is providing those as an option for states to use.

Under CAA section 111(d), each state must develop, adopt, and then submit its plan to the EPA. For its CAA section 111(d) plan, a state will determine whether to apply these emission performance rates to each affected EGU, individually or together, or to take an alternative approach and meet either an equivalent statewide rate-based goal or an equivalent statewide mass-based goal, as provided by the EPA in this rulemaking.

States with one or more affected EGUs will be required to develop and implement plans that set emission standards for affected EGUs. The CAA section 111(d) emission guidelines that the EPA is promulgating in this action apply to only the 48 contiguous states and any Indian tribe that has been approved by the EPA pursuant to 40 CFR 49.9 as eligible to develop and implement a CAA section 111(d) plan.[281] Because Vermont and the District of Columbia do not have affected EGUs, they will not be required to submit a state plan. Because the EPA does not possess all of the information or analytical tools needed to quantify the BSER for the two non-contiguous states with otherwise affected EGUs (Alaska and Hawaii) and the two U.S. territories with otherwise affected EGUs (Guam and Puerto Rico), these emission guidelines do not apply to those areas, and those areas will not be required to submit state plans on the schedule required by this final action.

In developing its CAA section 111(d) plan, a state will have the option of choosing from two different approaches: (1) An ''emission standards'' approach, or (2) a ''state measures'' approach. With an emission standards approach, a state will apply all requirements for achieving the subcategory-specific CO_2 emission performance rates or the state-specific CO_2 emission goal to affected EGUs in the form of federally enforceable emission standards. With a state measures approach, a state plan would be comprised, at least in part, of measures implemented by the state that are not included as federally enforceable components of the plan, along with a backstop of federally enforceable emission standards for affected EGUs that would apply in the event the plan does not achieve its anticipated level of CO_2 emission performance.

The EPA is requiring states to make their final plan submittals by September 6, 2016, or to make an initial submittal by this date in order to obtain an extension for making their final plan submittals no later than September 6, 2018, which is 3 years from the signature date of the rule. In order to receive an extension, states, in the initial submittal, must address three required components sufficiently to demonstrate that a state is able to undertake steps and processes necessary to timely submit a final plan by the extended date of September 6, 2018. The first required component is identification of final plan approach or approaches under consideration, including a description of progress made to date. The second required component is an appropriate explanation for why the state requires additional time to submit a final plan beyond September 6, 2016. The third required component for states to address in the initial submittal is a demonstration of how they have been engaging with the public, including vulnerable communities, and a description of how they intend to meaningfully engage with community stakeholders during the additional time (if an extension is granted) for development of the final plan.

Affected EGUs must achieve the final emission performance rates or equivalent state goals by 2030 and maintain that level thereafter. The EPA is establishing an 8-year interim period over which states must achieve the full required reductions to meet the CO_2 performance rates, and this begins in 2022. This 8-year interim period from 2022 through 2029, is separated into three steps, 2022–2024, 2025–2027, and 2028–2029, each associated with its own interim CO_2 emission performance rates that states must meet, as explained in Section VI of this preamble.

For the final emission guidelines, the EPA is revising the list of components required in a final state plan submittal to reflect: (1) Components required for all state plan submittals; (2) components required for the emission standards approach; and (3) components required for the state measures approach. The revised list of components also reflects the approvability criteria, which are no longer separate from the state plan submittal components.

All state plans must include the following components:

- Description of the plan approach and geographic scope
- Identification of the state's CO_2 interim period goal (for 2022–2029), interim steps (interim step goal 1 for 2022–2024; interim step goal 2 for 2025–2027; interim step goal 3 for 2028–2029) and final CO_2 emission goal of 2030 and beyond
- Demonstration that the plan submittal is projected to achieve the state's CO_2 emission goal[282]
- State recordkeeping and reporting requirements
- Certification of hearing on state plan
- Supporting documentation

Also, in all state plans, as part of the supporting documentation, a state must include a description of how they considered reliability in developing its state plan.

State plan submittals using the emission standards approach must also include:

- Identification of each affected EGU; identification of federally enforceable emission standards for the affected EGUs; and monitoring, recordkeeping and reporting requirements.
- Demonstrations that each emission standard will result in reductions that are quantifiable, non-duplicative, permanent, verifiable, and enforceable.

State plan submittals using the state measures approach must also include:

- Identification of each affected EGU; identification of federally enforceable emission standards for affected EGUs (if applicable); identification of backstop of federally enforceable emission standards; and monitoring, recordkeeping and reporting requirements.
- Identification of each state measure and demonstration that each state measure will result in reductions that are quantifiable, non-duplicative, permanent, verifiable, and enforceable.

In addition to these requirements, each state plan must follow the EPA implementing regulations at 40 CFR 60.23.

If a state with affected EGUs does not submit a plan or if the EPA does not approve a state's plan, then under CAA section 111(d)(2)(A), the EPA must establish a plan for that state. A state that has no affected EGUs must document this in a formal negative declaration submitted to the EPA by September 6, 2016. In the case of a tribe that has one or more affected EGUs in its area of Indian country,[283] the tribe has the opportunity, but not the obligation, to establish a CAA section 111(d) plan for its area of Indian country. If a tribe with one or more affected EGUs located in its area of

[281] In the case of a tribe that has one or more affected EGUs in its area of Indian country, the tribe has the opportunity, but not the obligation, to establish a CO_2 emission standard for each affected EGU located in its area of Indian country and a CAA section 111(d) plan for its area of Indian country. If the tribe chooses to establish its own plan, it must seek and obtain authority from the EPA to do so pursuant to 40 CFR 49.9. If it chooses not to seek this authority, the EPA has the responsibility to determine whether it is necessary or appropriate, in order to protect air quality, to establish a CAA section 111(d) plan for an area of Indian country where affected EGUs are located.

[282] A state that chooses to set emission standards that are identical to the emission performance rates for both the interim period and in 2030 and beyond need not identify interim state goals nor include a separate demonstration that its plan will achieve the state goals.

[283] The EPA is aware of at least four affected EGUs located in Indian country: Two on Navajo lands, the Navajo Generating Station and the Four Corners Power Plant; one on Ute lands, the Bonanza Power Plant; and one on Fort Mojave lands, the South Point Energy Center. The affected EGUs at the first three plants are coal-fired EGUs. The fourth affected EGU is an NGCC facility.

Indian country does not submit a plan or does not receive EPA approval of a submitted plan, the EPA has the responsibility to establish a CAA section 111(d) plan for that area if it determines that such a plan is necessary or appropriate.

During implementation of its approved state plan, each state must demonstrate to the EPA that its affected EGUs are meeting the interim and final performance requirements included in this final rule through monitoring and reporting requirements. State plan requirements and flexibilities are described more fully in Section VIII of this preamble.

B. Brief Summary of Legal Basis

This rule is consistent with the requirements of CAA section 111(d) and the implementing regulations.[284] As an initial matter, the EPA reasonably interprets the provisions identifying which air pollutants are covered under CAA section 111(d) to authorize the EPA to regulate CO_2 from fossil fuel-fired EGUs. In addition, the EPA recognizes that CAA section 111(d) applies to sources that, if they were new sources, would be covered under a CAA section 111(b) rule. Concurrently with this rule, the EPA is finalizing a CAA section 111(b) rulemaking establishing standards of performance for CO_2 emissions from new fossil fuel-fired EGUs, from modified fossil fuel-fired EGUs, and from reconstructed fossil fuel-fired EGUs, and any of those sets of section 111(b) standards of performance provides the requisite predicate for this rulemaking.

A key step in promulgating requirements under CAA section 111(d)(1) is determining the ''best system of emission reduction which . . . the Administrator determines has been adequately demonstrated'' (BSER) under CAA section 111(a)(1). It is clear by the terms of section 111(a)(1) and the implementing regulations for section 111(d) that the EPA is authorized to determine the BSER; [285] accordingly, in this rulemaking, the EPA is determining the BSER.

The EPA is finalizing the BSER for fossil fuel-fired EGUs based on building blocks 1, 2, and 3. Building block 1 includes operational improvements and equipment upgrades that the coal-fired steam-generating EGUs in the state may undertake to improve their heat rate. It qualifies as part of the BSER because it improves the carbon intensity of the affected EGUs in generating electricity through actions the affected sources may undertake that are adequately demonstrated and whose cost is ''reasonable.'' Building blocks 2 and 3 include increases in low- or zero-emitting generation which substitute for generation from the affected EGUs and thereby reduce CO_2 emissions from those sources. All of these measures are components of a ''system of emission reduction'' for the affected EGUs because they entail actions that the affected EGUs may themselves undertake that have the effect of reducing their emissions. Further, these measures meet the criteria in CAA section 111(a)(1) and the case law for the ''best'' system of emission reduction that is ''adequately demonstrated'' because they achieve the appropriate level of reductions, their cost is ''reasonable,'' they do not have adverse non-air quality health and environmental impacts or impose adverse energy requirements, and they are each well-established among affected EGUs. It should be emphasized that these measures are consistent with current trends in the electricity sector.

Building blocks 2 and 3 may be implemented through a set of measures, including reduced generation from the fossil fuel-fired EGUs. These measures do not, however, reduce the amount of electricity that can be sold or that is available to end users. In addition, states should be expected to allow their affected EGUs to trade rate-based emission credits or mass-based emission allowances (trading) because trading is well-established for this industry and has the effect of focusing costs on the affected EGUs for which reducing emissions is most cost-effective. Because trading facilitates implementation of the building blocks and may help to optimize cost-effectiveness, trading is a method of implementing the BSER as well.

As a result, an affected EGU has a set of choices for achieving its emission standards. For example, an affected coal-fired steam generating unit can achieve a rate-based standard through a set of actions that implement the building block 1 measures and that implement the building block 2 and 3 measures through a set of actions that range from purchasing full or partial interest in existing NGCC or new RE assets to purchasing ERCs that represent the environmental attributes of increased NGCC generation or new renewable generation. In addition, the affected EGU may reduce its generation and thereby reduce the extent that it needs to implement the building blocks. The affected EGU may also purchase rate-based emission credits from other affected EGUs. If the state chooses to impose a mass-based emission standard, the coal-fired steam generating unit may implement building block 1 measures, purchase mass-based emission allowances from other affected EGUs, or reduce its generation. In light of the available sources of lower- and zero-emitting replacement generation, this approach would achieve an appropriate level of emission reductions and maintain the reliability of the electricity system.

With the promulgation of the emission guidelines, each state must develop and submit a plan to achieve the CO_2 emission performance rates established by the EPA or the equivalent statewide rate-based or mass-based goal provided by the EPA in this rule. The EPA interprets CAA section 111(d) to allow states to establish standards of performance and provide for their implementation and enforcement through either the ''emission standards'' or the ''state measures'' plan type. In the case of the ''emission standards'' plan type, the emission standards establish standards of performance, and the other components of the plan provide for their implementation and enforcement. In the case of the ''state measures'' plan type, –the state submits a plan that relies upon measures that are only enforceable as a matter of state law that will, in conjunction with any emission standards on affected EGUs, result in the achievement of the applicable performance rates or state goals by the affected EGUs. Under the state measures plan type, states must also submit a federally enforceable backstop and a mechanism that would trigger implementation of the backstop; therefore, in a state measures plan, the standards of performance take the form of the backstop, the trigger mechanism provides for the implementation of such backstop, and the other required components of the plan provide for

[284] Under CAA section 111(d), there is no requirement that the EPA make a finding that the emissions from existing sources that are the subject of regulation cause or contribute significantly to air pollution which may reasonably be anticipated to endanger public health or welfare. As predicates to promulgating regulations under CAA section 111(d) for existing sources, the EPA must make endangerment and cause-or-contribute-significantly findings for emissions from the source category, and the EPA must promulgate regulations for new sources in the source category. In the CAA section 111(b) rule for CO_2 emissions for new affected EGUs that the EPA is promulgating concurrently with this rule, the EPA discusses the endangerment and cause-or-contribute-significantly findings and explains why the EPA has already made them for the affected EGU source categories so that the EPA is not required to make them for CO_2 emissions from affected EGUs, and, in the alternative, why, if the EPA were required to make those findings, it was making them in that rulemaking.

[285] The EPA is not re-opening that interpretation in this rulemaking.

implementation and enforcement of the standards of performance.

These two types of state plans and their respective approaches, which could be implemented on a single-state or multi-state basis, allow states to meet the statutory requirements of section 111(d) while accommodating the wide range of regulatory requirements and other programs that states have deployed or will deploy in the electricity sector that reduce CO_2 emissions from affected EGUs. It should be noted that both state plan types allow the state flexibility in assigning the emission performance obligations to its affected EGUs in the form of standards of performance as long as the required emission performance level is met. Both plan types harness the efficiencies of emission reduction opportunities in the interconnected electricity system and are fully consistent with the principles of cooperative federalism that underlie the Clean Air Act generally and CAA section 111(d) particularly. That is, both plan types achieve the emission performance requirements through the vehicle of a state plan, and provide each state significant flexibility to take local circumstances and state policy goals into account in determining how to reduce emissions from its affected sources, as long as the plan meets minimum federal requirements.

Both state plan types, and the standards of performance for the affected EGUs that the states will establish through the state plan process, are consistent with the applicable CAA section 111 provisions. A state has discretion in determining the appropriate measures to rely upon for its plan. The state may adopt measures that assure the achievement of the requisite CO_2 emission performance rate or state goal by the affected EGUs, and is not limited to the measures that the EPA identifies as part of the BSER.

In this rulemaking, the EPA establishes reasonable deadlines for state plan submission. Under CAA section 111(d)(1), state plans must ''provide for implementation and enforcement'' of the standards of performance, and under CAA section 111(d)(2), the state plans must be ''satisfactory'' for the EPA to approve them. In this rulemaking, the EPA is finalizing the criteria that the state plans must meet under these requirements.

The EPA discusses its legal interpretation in more detail in other parts of this preamble and provides additional information about certain issues in the Legal Memorandum included in the docket for this rulemaking.

IV. Authority for This Rulemaking, Definition of Affected Sources, and Treatment of Source Categories

A. EPA's Authority Under CAA Section 111(d)

EPA's authority for this rule is CAA section 111(d). CAA section 111(d) provides that the EPA will promulgate regulations under which each state will establish standards of performance for existing sources for any air pollutant that meets two criteria. First, CAA section 111(d) applies to air pollutants that are not regulated as a criteria pollutant under section 108 or as a hazardous air pollutant (HAP) under CAA section 112. 42 U.S.C. 7411(d)(1)(A)(i).[286] Second, section 111(d) applies only to air pollutants for which the existing source would be regulated under section 111 if it were a new source. 42 U.S.C. 7411(d)(1)(A)(ii). Here, carbon dioxide (CO_2) meets both criteria: (1) It is not a criteria pollutant regulated under section 108 nor a HAP regulated under CAA section 112, and (2) CO_2 emissions from new power plants (including newly constructed, modified and reconstructed power plants) are regulated under the CAA section 111(b) rule that is being finalized along with this rule.

B. CAA Section 112 Exclusion to CAA Section 111(d) Authority

CAA section 111(d) contains an exclusion that limits the regulation under CAA section 111(d) of air pollutants that are regulated under CAA section 112. 42 U.S.C. 7411(d)(1)(A)(i). This ''Section 112 Exclusion'' in CAA section 111(d) was the subject of a significant number of comments based on two differing amendments to this exclusion enacted in the 1990 CAA Amendments. As discussed in more detail below, the House and the Senate each initially passed different amendments to the Section 112 Exclusion and both amendments were ultimately passed by both houses and signed into law. In 2005, in connection with the Clean Air Mercury Rule (CAMR), the EPA discussed the agency's interpretation of the Section 112 Exclusion in light of these two differing amendments and concluded that the two amendments were in conflict and that the provision should be read as follows to give both amendments meaning: where a source category has been regulated under CAA section 112, a CAA section 111(d) standard of performance cannot be established to address any HAP listed under CAA section 112(b) that may be emitted from that particular source category. See 70 FR 15994, 16029–32 (March 29, 2005).

In June 2014, the EPA presented this previous interpretation as part of the proposal and requested comment on it. The EPA received numerous comments on its previous interpretation, including comments on the proper interpretation and effect of each of the two differing amendments, and whether the Section 112 Exclusion should be read to mean that the EPA's regulation of HAP from power plants under CAA section 112 bars the EPA from establishing CAA section 111(d) regulations covering CO_2 emissions from power plants. In particular, many comments focused on two specific issues. First, some commenters—including some industry and state commenters that had previously endorsed the EPA's interpretation of the Section 112 Exclusion in other contexts[287]—argued that the EPA's 2005 interpretation was in error because it allowed the regulation of certain pollutants from source categories under CAA section 111(d) when those source categories were also regulated for different pollutants under CAA section 112. Second, some commenters argued that the EPA's previous interpretation of the House amendment (as originally represented in 2005 at 70 FR at 16029–30) was in error because it improperly read that amendment as focusing on whether a source category was regulated under CAA section 112 rather than on whether the air pollutant was regulated under CAA section 112, and that improper reading lead to an interpretation that was inconsistent with the structure and purpose of the CAA.

In light of the comments, the EPA has reconsidered its previous interpretation of the Section 112 Exclusion and, in particular, considered whether the exclusion precludes the regulation under CAA section 111(d) of CO_2 from power plants given that power plants are regulated for certain HAP under CAA section 112. On this issue, the EPA

[286] Section 111(d) might be read to apply to HAP under certain circumstances. However, because carbon dioxide is not a HAP, this issue does not need to be resolved in the context of this rule.

[287] For example, in the CAMR litigation (*State of New Jersey* v. *EPA,* No. 05–1097 (D.C. Cir.), the joint brief filed by a group of intervenors and an amicus (including six states and the West Virginia Department of Environmental Protection, and Utility Air Regulatory Group and nine other industry entities) stated that the EPA had interpreted section 111(d) in light of the two different amendments and that the EPA's interpretation was ''a reasoned way to reconcile the conflicting language and the Court should defer to the EPA's interpretation.'' Joint Brief of State Respondent-Intervenors, Industry Respondent-Intervernors, and State Amicus, filed May 18, 2007, at 25.

has concluded that the two differing amendments are not properly read as conflicting. Instead, the House amendment and the Senate Amendment should each be read to mean the same in the context presented by this rule: that the Section 112 Exclusion does not bar the regulation under CAA section 111(d) of non-HAP from a source category, regardless of whether that source category is subject to standards for HAP under CAA section 112. In reaching this conclusion, the EPA has revised its previous interpretation of the House amendment, as discussed below.

1. Structure of the CAA and Pre-1990 Section 112 Exclusion

The Clean Air Act sets out a comprehensive scheme for air pollution control, addressing three general categories of pollutants emitted from stationary sources: (1) Criteria pollutants (which are addressed in sections 108–110); (2) hazardous pollutants (which are addressed under section 112); and (3) ''pollutants that are (or may be) harmful to public health or welfare but are not or cannot be controlled under sections 108–110 or 112.'' 40 FR 53340 (Nov. 17, 1975).

Six ''criteria'' pollutants are regulated under sections 108–110. These are pollutants that the Administrator has concluded ''cause or contribute to air pollution which may reasonably be anticipated to endanger public health or welfare;'' ''the presence of which in the ambient air results from numerous and diverse mobile or stationary sources;'' and for which the Administrator has issued, or plans to issue, ''air quality criteria. 42 U.S.C. 7408(a)(1). Once the EPA issues air quality criteria for such pollutants, the Administrator must propose primary National Ambient Air Quality Standards (NAAQS) for them, set at levels ''requisite to protect the public health'' with an ''adequate margin of safety.'' 42 U.S.C. 7409(a)-(b). States must then adopt plans for implementing NAAQS. 42 U.S.C. 7410.

HAP are regulated under CAA section 112 and include the pollutants listed by Congress in section 112(b)(1) and other pollutants that the EPA lists under sections 112(b)(2) and (b)(3). CAA section 112 further provides that the EPA will publish and revise a list of ''major'' and ''area'' source categories of HAP, and then establish emissions standards for HAP emitted by sources within each listed category. 42 U.S.C. 7412(c)(1) & (2).

CAA section 111, 42 U.S.C. 7411, is the third part of the CAA's structure for regulating stationary sources. Section 111 has two main components. First, section 111(b) requires the EPA to promulgate federal ''standards of performance'' addressing *new* stationary sources that cause or contribute significantly to ''air pollution which may reasonably be anticipated to endanger public health or welfare.'' 42 U.S.C. 7411(b)(1)(A). Once the EPA has set *new* source standards addressing emissions of a particular pollutant under CAA section 111(b), CAA section 111(d) provides that the EPA will promulgate regulations requiring states to establish standards of performance for *existing* stationary sources of the same pollutant. 42 U.S.C. 7411(d)(1).

Together, the criteria pollutant/NAAQS provisions in sections 108–110, the hazardous air pollutant provisions in section 112, and performance standard provisions in section 111 constitute a comprehensive scheme to regulate air pollutants with ''no gaps in control activities pertaining to stationary source emissions that pose any significant danger to public health or welfare.'' S. Rep. No. 91–1196, at 20 (1970).[288]

The specific role of CAA section 111(d) in this structure can be seen in CAA subsection 111(d)(1)(A)(i), which provides that regulation under CAA section 111(d) is intended to cover pollutants that are not regulated under either the criteria pollutant/NAAQS provisions or section 112. Prior to 1990, this limitation was laid out in plain language, which stated that CAA section 111(d) regulation applied to ''any air pollutant . . . for which air quality criteria have not been issued or which is not included on a list published under section [108(a)] or [112(b)(1)(A)].'' This plain language demonstrated that section 111(d) is designed to regulate pollutants from existing sources that fall in the gap not covered by the criteria pollutant provisions or the hazardous air pollutant provisions.

This gap-filling purpose can be seen in the early legislative history of the CAA. As originally enacted in the 1970 CAA, the precursor to CAA section 111 (which was originally section 114) was described as covering pollutants that would not be controlled by the criteria pollutant provisions or the hazardous air pollutant provisions. See S. Committee Rep. to accompany S. 4358 (Sept. 17, 1970), 1970 CAA Legis. Hist. at 420 (''It should be noted that the emission standards for pollutants which cannot be considered hazardous (as defined in section 115 [which later became section 112]) could be established under section 114 [later, section 111]. Thus, there should be no gaps in control activities pertaining to stationary source emissions that pose any significant danger to public health or welfare.''); Statement by S. Muskie, S. Debate on S. 4358 (Sept. 21, 1970), 1970 CAA Legis. Hist. at 227 (''[T]he bill [in section 114] provides the Secretary with the authority to set emission standards for selected pollutants which cannot be controlled through the ambient air quality standards and which are not hazardous substances.'').

2. The 1990 Amendments to the Section 112 Exclusion

The Act was amended extensively in 1990. Among other things, Congress sought to accelerate the EPA's regulation of hazardous pollutants under section 112. To that end, Congress established a lengthy list of HAP; set criteria for listing ''source categories'' of such pollutants; and required the EPA to establish standards for each listed source category's hazardous pollutant emissions. 42 U.S.C. 7412(b), (c) and (d). In the course of overhauling the regulation of HAP under section 112, Congress needed to edit section 111(d)'s reference to section 112(b)(1)(A), which was to be eliminated as part of the revisions to section 112.

To address the obsolete cross-reference to section 7412(b)(1)(A), Congress passed two differing amendments—one from the Senate and one from the House—that were never reconciled in conference. The Senate amendment replaced the cross reference to old section 112(b)(1)(A) with a cross-reference to new section 112. Pub. L. 101–549, § 302(a), 104 Stat. 2399, 2574 (1990). The House amendment replaced the cross-reference with the phrase ''emitted from a source category which is regulated under section [112].'' Pub. L. 101–549, § 108(g), 104 Stat. 2399, 2467 (1990).[289] Both amendments were

[288] In subsequent CAA amendments, Congress has maintained this three-part scheme, but supplemented it with the Preservation of Significant Deterioration (PSD) program, the Acid Rain Program and the Regional Haze program.

[289] Originally, when the House bill to amend the CAA was introduced in January 1989, it focused on amendments to control HAP. Of particular note, the amendments to section 112 included a provision that excluded regulation under section 112 of ''[a]ny air pollutant which is included on the list under section 108(a), or which is regulated for a source category under section 111(d).'' H.R. 4, § 2 (Jan. 3, 1989), 1990 CAA Legist. Hist. at 4046. In other words, the Section 112 Exclusion in section 111(d) that was ultimately contained in the House amendment was originally crafted as what might be called a ''Section 111(d) Exclusion'' in section 112. This is significant because the ''source category'' phrasing in the original January 1989 text with respect to section 111(d) makes sense, whereas the ''source category'' phrasing in the 1990 House amendment does not. When referring to the scope of what is regulated under section 111(d), it makes sense to frame that scope with respect to source

Continued

enacted into law, and thus both are part of the current CAA. To determine how this provision is properly applied in light of the two differing amendments, we first look at the Senate amendment, then at the House amendment, then discuss how the two amendments are properly read together.

3. The Senate Amendment is Clear and Unambiguous

Unlike the ambiguous amendment to CAA section 111(d) in the House amendment (discussed below), the Senate amendment is straightforward and unambiguous. It maintained the pre-1990 meaning of the Section 112 Exclusion by simply substituting ''section 112(b)'' for the prior cross-reference to ''section 112(b)(1)(A).'' Pub. L. 101–549, § 302(a), 104 Stat. 2399, 2574 (1990). So amended, CAA section 111(d) mandates that the EPA require states to submit plans establishing standards for ''any air pollutant . . . which is not included on a list published under section [108(a)] or section [112(b)].'' Thus, the Section 112 Exclusion resulting from the Senate amendment would preclude CAA section 111(d) regulation of HAP emission but would not preclude CAA section 111(d) regulation of CO_2 emissions from power plants notwithstanding that power plants are also regulated for HAP under CAA section 112.

Some commenters have argued that the Senate amendment should be given no effect, because only the House amendment is shown in the U.S. Code, and because the Senate amendment appeared under the heading ''conforming amendments,'' and for various other reasons. The EPA disagrees. The Senate amendment, like the House amendment, was enacted into law as part of the 1990 CAA amendments, and must be given effect.

First, that the U.S. Code only reflects the House amendment does not change the fact that both amendments were signed into law as part of the 1990 Amendments, as shown in the Statutes at Large. Pub. L. 101–549, §§ 108(g) and 302(a), 104 Stat. 2399, 2467, 2574 (1990). Where there is a conflict between the U.S. Code and the Statutes at Large, the latter controls. See 1 U.S.C. 112 & 204(a); *Stephan* v. *United States,* 319 U.S. 423, 426 (1943) (''the Code cannot prevail over the Statutes at Large when the two are inconsistent''); *Five Flags Pipe Line Co.* v. *Dep't of Transp.,* 854 F.2d 1438, 1440 (D.C. Cir. 1988) (''[W]here the language of the Statutes at Large conflicts with the language in the United States Code that has not been enacted into positive law, the language of the Statutes at Large controls.'').

Second, the ''conforming'' label is irrelevant. A ''conforming'' amendment may be either substantive or non-substantive. *Burgess* v. *United States,* 553 U.S. 124, 135 (2008). And while the House Amendment contains more words, it also qualifies as a ''conforming amendment'' under the definition in the Senate Legislative Drafting Manual, Section 126(b)(2) (defining ''conforming amendments'' as those ''necessitated by the substantive amendments of provisions of the bill''). Here, both the House and Senate amendments were ''necessitated by'' Congress' revisions to section 112 in the 1990 CAA Amendment, which included the deletion of old section 112(b)(1)(A). Thus, the House's amendment is no less ''conforming'' than the Senate's, and the heading under which it was enacted (''Miscellaneous Guidance'') does not suggest any more importance than ''Conforming Amendments.'' In any event, courts gives full effect to conforming amendments, *see Washington Hosp. Ctr.* v. *Bowen,* 795 F.2d 139, 149 (D.C. Cir. 1986), and so neither the Senate Amendment nor the House amendment can be ignored.

Third, the legislative history of the Senate amendment supports the conclusion that the substitution of the updated cross-reference was not a mindless, ministerial decision, but reflected a decision to choose an update of the cross reference instead of the text that was inserted into the Section 112 Exclusion by the House amendment. In mid-1989, the House and Senate introduced identical bills (H.R. 3030 and S. 1490, respectively) to provide for ''miscellaneous'' changes to the CAA. In both the Senate and House bills as they were introduced in mid-1989, the Section 112 Exclusion was to be amended by taking out ''or 112(b)(1)(A)'' and inserting ''or emitted from a source category which is regulated under section 112.'' H.R. 3030, as introduced, 101st Cong. § 108 (Jul. 27, 1989); S. 1490, as introduced, 101st Cong. § 108 (Aug. 3, 1989). See 1990 CAA Legis. Hist. at 3857 (noting that H.R. 3030 and S.1490, as introduced, were the same). Although S. 1490 was identical to H.R. 3030 when they were introduced, the Senate reported a vastly different bill (S.1630) at the end of 1989. See S. 1630, as reported (Dec. 20, 1989), 1990 CAA Legis. Hist. at 7906. As reported and eventually passed, S. 1630 did not contain the text in the House amendment (''or emitted from a source category which is regulated under section 112'') and instead contained the substitution of cross references (changing ''section 112(b)(1)(A)'' to ''section 112(b)''). *See* S. 1630, as reported, 101st Cong. § 305, 1990 CAA Legis. Hist. at 8153; S. 1630, as passed, § 305 (Apr. 3, 1990), 1990 CAA Legis. Hist. at 4534. Though the EPA is not aware of any statements in the legislative history that expressly explain the Senate's intent in making these changes to the Senate bill, the sequence itself supports the conclusion that the Senate's substitution reflects a decision to retain the pre-1990 approach of using a cross-reference to 112(b) to define the scope of the Section 112 Exclusion. Whether the difference in approach between the final Senate amendment in S.1630 and the House amendment in H.R. 3030 creates a substantive difference or are simply two different means of achieving the same end depends on what interpretation one gives to the text in the House amendment, which we turn to next.

4. The House Amendment

a. *The House amendment is ambiguous.* Before looking at the specific text of the House amendment, it is helpful to review some principles of statutory interpretation. First, statutory interpretation begins with the text, but does not end there. As the D.C. Circuit Court has explained, ''[t]he literal language of a provision taken out of context cannot provide conclusive proof of congressional intent.'' *Bell Atlantic Telephone Cos.* v. *F.C.C.,* 131 F.3d 1044, 1047 (D.C. Cir. 1977). See *King* v. *Burwell*, 2015 U.S. LEXIS 4248, *19(''[O]ftentimes the 'meaning—or ambiguity—of certain words or phrases may only become evident when placed in context.' *Brown & Williamson,* 529 U. S., at 132, 120 S. Ct. 1291, 146 L. Ed. 2d 121. So when deciding whether the language is plain, we must read the words 'in their context and with a view to their place in the overall statutory scheme.' Id., at 133, 120 S. Ct. 1291, 146 L. Ed. 2d 121 (internal quotation marks omitted). Our duty, after all, is 'to construe statutes, not isolated provisions.' *Graham County Soil and*

categories, because section 111 regulation begins with the identification of source categories under section 111(b)(1)(A). By contrast, regulation under section 112 begins with the identification of HAP under section 112(b); the listing of source categories under section 112(c) is secondary to the listing of HAP. From this history, and in light of this difference between the scope of what is regulated in sections 111 and 112, it is reasonable to conclude that the ''source category'' phrasing is a legacy from the original 1989 bill—that is, when converting the 1989 text into the Section 112 Exclusion that we see in the 1990 House amendment, the legislative drafters continued to use phrasing based on ''source category'' notwithstanding that this phrasing created a mismatch with the way that the scope of section 112 regulation is determined.

Water Conservation Dist. v. *United States ex rel. Wilson,* 559 U. S. 280, 290, 130 S. Ct. 1396, 176 L. Ed. 2d 225 (2010) (internal quotation marks omitted).''). In addition, statutes should not be given a ''hyperliteral'' reading that is contrary to established canons of statutory construction and common sense. *See RadLAX Gateway Hotel* v. *Amalgamated Bank,* 132 S.Ct. 2065, 2070–71 (2012).

Further, a proper reading of statutory text ''must employ all the tools of statutory interpretation, including text, structure, purpose, and legislative history.'' *Loving* v. *I.R.S.,* 742 F.3d 1013, 1016 (D.C. Cir. 2014) (internal quotation omitted). See, also, *Robinson* v. *Shell Oil Co.,* 519 U.S. 337, 341 (1997) (statutory interpretation involves consideration of ''the language itself, the specific context in which that language is used, and the broader context of the statute as a whole.''). Moreover, one principle of statutory construction that has particular application here is that provisions in a statute should be read to be consistent, rather than conflicting, if possible. This principle was discussed in the recent case of *Scialabba* v. *Cuellar De Osorio,* 134 S. Ct. 2191, 2214 (concurring opinion by Chief Justice Roberts and Justice Scalia), 2219–2220 (dissent by Justices Sotomayor, Breyer and Thomas)(2014). As Justice Sotomayor wrote (at 134 S. Ct. at 2220):

> ''We do not lightly presume that Congress has legislated in self-contradicting terms. See A. Scalia & B. Garner, Reading Law: The Interpretation of Legal Texts 180 (2012) (''The provisions of a text should be interpreted in a way that renders them compatible, not contradictory. . . . [T]here can be no justification for needlessly rendering provisions in conflict if they can be interpreted harmoniously''). . . . Thus, time and again we have stressed our duty to ''fit, if possible, all parts [of a statute] into [a] harmonious whole.'' *FTC* v. *Mandel Brothers, Inc.*, 359 U.S. 385, 389, 79 S. Ct. 818, 3 L. Ed. 2d 893 (1959); see also *Morton* v. *Mancari*, 417 U.S. 535, 551, 94 S. Ct. 2474, 41 L. Ed. 2d 290 (1974) (when two provisions ''are capable of co-existence, it is the duty of the courts . . . to regard each as effective''). In reviewing an agency's construction of a statute, courts ''must,'' we have emphasized, ''interpret the statute 'as a . . . coherent regulatory scheme' '' rather than an internally inconsistent muddle, at war with itself and defective from the day it was written. Brown & Williamson, 529 U.S., at 133, 120 S. Ct. 1291, 146 L. Ed. 2d 121.

As amended by the House, CAA section 111(d)(1)(A)(i) limits CAA section 111(d) to any air pollutant ''for which air quality criteria have not been issued or which is not included on a list published under section 7408(a) of this title or emitted from a source category which is regulated under section 7412 of this title . . .'' This statutory text is ambiguous and subject to numerous possible readings.

First, the text of the House-amended version of CAA section 111(d) could be read literally as authorizing the regulation of any pollutant that is not a criteria pollutant. This reading arises if one focuses on the use of ''or'' to join the three clauses:

> The Administrator shall prescribe regulations . . . under which each State shall submit to the Administrator a plan which establishes standards of performance for any existing source for any air pollutant [1] for which air quality criteria have not been issued or [2] which is not included on a list published under section 7408(a) of this title or [3] emitted from a source category which is regulated under section 7412 of this title. . . .

42 U.S.C. 7411(d)(1) (emphasis and internal numbering added). Because the text contains the conjunction ''or'' rather than ''and'' between the three clauses, a literal reading could read the three clauses as alternatives, rather than requirements to be imposed simultaneously. In other words, a literal reading of the language of section 111(d) provides that the Administrator may require states to establish standards for an air pollutant so long as *either* air quality criteria have not been established for that pollutant, *or* one of the remaining criteria is met. If this reading were applied to determine whether the EPA may promulgate CAA section 111(d) regulations for CO_2 from power plants, the result would be that CO_2 from power plants could be regulated under CAA section 111(b) because air quality criteria have not been issued for CO_2 and therefore whether CO_2 or power plants are regulated under CAA section 112 would be irrelevant. This reading, however, is not a reasonable reading of the statute because, among other reasons, it gives little or no meaning to the limitation covering HAP that are regulated under CAA section 112 and thus is contrary to both the CAA's comprehensive scheme created by the three sets of provisions (under which CAA section 111 is not intended to duplicate the regulation of pollutants regulated under section 112) and the principle of statutory construction that text should not be construed such that a provision does not have effect.

A second reading of CAA section 111(d) as revised by the House amendment focuses on the lack of a negative before the third clause. That is, unlike the first and second clauses that each contain negative phrases (either ''has not been issued'' or ''which is not included''), the third clause does not. One could presume that the negative from the second clause was intended to carry over, implicitly inserting another ''which is not'' before ''emitted from a source category which is regulated under section [112].'' But that is a presumption, and not the plain language of the statute. The text as amended by the House says that the EPA ''shall'' prescribe regulations for ''any air pollutant . . . emitted from a source category which is regulated under section [112].'' 42 U.S.C. 7411(d)(1). Thus, CAA section 111(d)(1)(A)(i) could be read as providing for the regulation of emissions of pollutants if they are emitted from a source category that is regulated under CAA section 112. Like the first reading discussed above, this reading would authorize the regulation of CO_2 emissions from existing power plants under CAA section 111(d). But, this second reading is not reasonable because it would provide for the regulation of a source's HAP emissions under CAA section 111(d) when those same emissions were also subject to standards under CAA section 112. Thus, this reading would be contrary to Congress's intent that CAA section 111(d) regulation fill the gap between the other programs by covering pollutants that the other programs do not, but not duplicate the regulation of pollutants that the other programs cover.

If one does presume that the ''which is not'' phrase is intended to carry over to the third clause, then CAA section 111(d) regulation under the House amendment would be limited to ''any air pollutant . . . which is not . . . emitted from a source category which is regulated under section [112].'' Even with this presumption, however, the House amendment contains further ambiguities with respect to the phrases ''a source category'' and ''regulated under section 112,'' and how those phrases are used within the structure of the provision limiting what air pollutants may be regulated under CAA section 111(d).

The phrase ''regulated under section 112'' is ambiguous. As the Supreme Court has explained in the context of other statutes using a variation of the word ''regulate,'' an agency must consider what is being regulated. See *Rush Prudential HMO, Inc.* v. *Moran,* 536 U.S. 355, 366 (2002) (It is necessary to ''pars[e] . . . the 'what' '' of the term ''regulates.''); *UNUM Life Ins. Co. of Am.* v. *Ward,* 526 U.S. 358, 363 (1999) (the term '' 'regulates insurance' . . . requires interpretation, for [its] meaning is not plain.''). Here, one possible reading is that the phase modifies the words ''a source category'' without regard to what pollutants are regulated under section 112, which then presents the issue of what meaning to give to the phrase ''a source category.''

Under this reading, and assuming the phrase ''a source category'' is read to mean the particular source category, the House amendment would preclude the regulation under CAA section 111(d) of a specific source category for any pollutant if that source category has been regulated for any HAP under CAA section 112.[290] The effect of this reading would be to preclude the regulation of CO_2 from power plants under CAA section 111(d) because power plants have been regulated for HAP under CAA section 112. This is the interpretation that the EPA applied to the House amendment in connection with the CAMR rule in 2005, when looking at the question of whether HAP can be regulated under CAA section 111(d) for a source category that is not regulated for HAP under section 112, and some commenters have advocated for this interpretation here. But, after considering all of the comments and reconsidering this interpretation, the EPA has concluded that this interpretation of the House amendment is not a reasonable reading because it would disrupt the comprehensive scheme for regulating existing sources created by the three sets of provisions covering criteria pollutants, HAP and the other pollutants that fall outside of those two programs and frustrate the role that section 111 is intended to play.[291] Specifically, under this interpretation, the EPA could not regulate a source category's emissions of *HAP* under CAA section 112, and then promulgate regulations for *other* pollutants from that source category under CAA section 111(d).[292] There is no reason to conclude that the House amendment was intended to abandon the existing structure and relationship between the three programs in this way. Indeed, Congress expressly provided that regulation under CAA section 112 was *not* to ''diminish or replace the requirements of'' the EPA's regulation of non-hazardous pollutants under section 7411. See 42 U.S.C. 7412(d)(7). Further, consistent with CAA section 112's direction that EPA list ''all categories and subcategories of major sources and area [aka, non-major] sources'' of HAP and then establish CAA section 112 standards for those categories and subcategories, 42 U.S.C. 7412(c)(1) and (c)(2), the EPA has listed and regulated over 140 categories of sources under CAA section 112. Thus, this reading would eviscerate the EPA's authority under section 111(d) and prevent it from serving as the gap-filling provision within the comprehensive scheme of the CAA as Congress intended.[293] In short, it is not reasonable to interpret the Section 112 Exclusion in section 111(d) to mean that the existence of CAA section 112 standards covering hazardous pollutants from a source category would entirely eliminate regulation of non-hazardous emissions from that source category under section 111(d).[294]

b. *The EPA's Interpretation of the House Amendment.* Having concluded that the interpretations discussed above are not reasonable, the EPA now turns to what it has concluded is the best, and sole reasonable, interpretation of the House amendment as it applies to the issue here.

The EPA's interpretation of the House amendment as applied to the issue presented in this rule is that the Section 112 Exclusion excludes the regulation of HAP under CAA section 112 if the source category at issue is regulated under CAA section 112, but does not exclude the regulation of other pollutants, regardless of whether that source category is subject to CAA section 112 standards. This interpretation reads the phrase ''regulated under section 112'' as modifying the words ''source category'' (as does the interpretation discussed above) but also recognizes that the phrase ''regulated under section 112'' refers only to the regulation of HAP emissions. In other words, the EPA's interpretation recognizes that source categories ''regulated under section 112'' are not regulated by CAA section 112 with respect to all pollutants, but only with respect to HAP. Thus, it is reasonable to interpret the House amendment of the Section 112 Exclusion as only excluding the regulation of HAP emissions under CAA section 111(d) and only when that source category is regulated under CAA section 112. We note that this interpretation of the House amendment alone is the same as the 2005 CAMR interpretation of the two amendments combined: Where a source category has been regulated under CAA section 112, a CAA section 111(d) standard of performance cannot be established to address any HAP listed under CAA section 112(b) that may be emitted from that particular source category. See 70 FR 15994, 16029–30 (March 29, 2005).

[290] ''A source category'' could also be interpreted to mean ''any source category.'' Under this interpretation, CAA 111(d) regulation would be limited to air pollutants that are not emitted by any source category for which the EPA has issued standards for HAP under CAA section 112. This interpretation is not reasonable because it would effectively read CAA 111(d) out of the statute. Given the extensive list of source categories regulated under CAA 112 and the breadth of pollutants emitted by those categories collectively, literally all air pollutants would be barred from CAA 111(d) regulation under this interpretation.

[291] In assessing any interpretation of section 111(d), EPA must consider how the three main programs set forth in the CAA work together. *See UARG,* 134 S. Ct. at 2442 (a ''reasonable statutory interpretation must account for . . . the broader context of the statute as a whole'') (quotation omitted).

[292] Supporters of this interpretation have noted that the EPA could regulate power plants under both CAA section 111(d) and CAA section 112 if it regulated under section 111(d) first, before the Section 112 Exclusion is triggered. But that argument actually further demonstrates another reason why this interpretation is unreasonable. There is no basis for concluding that Congress intended to mandate that section 111(d) regulation occur first, nor is there any logical reason why the need to regulate under section 111(d) should be dependent on the timing of such regulation in relation to CAA 112 regulation of that source category.

[293] Some commenters have stated that EPA could choose to regulate both HAP and non-HAP under section 111(d), and thus could regulate HAP without creating a gap. But this presumes that Congress intended EPA to have the choice of declining to regulate a section 112-listed source category for HAP under section 112, which is inconsistent with the mandatory language in section 112. See, *e.g.,* section 112(d)(1)(''The Administrator shall promulgate regulations establishing emissions standards for each category or subcategory of major sources and area sources of hazardous air pollutants listed for regulation pursuant to subsection (c) of this section in accordance with the schedules provided in subsections (c) and (e) of this section.''). Moreover, given the prescriptive language that Congress added into section 112 concerning how to set standards for HAP, see section 112(d)(2) and (d)(3), it is unreasonable to conclude that Congress intended that the EPA could simply choose to ignore the provisions in section 112 and instead regulate HAP for a section 112 listed source category under section 111(d).

Further, some supporters of this interpretation have suggested that EPA could regulate CO_2 under section 112. But this suggestion fails to consider that sources emitting HAP are major sources if they emit 10 tons of any HAP. See CAA section 112(a)(1). Thus, if CO_2 were regulated as a HAP, and because emissions of CO_2 tend to be many times greater than emissions of other pollutants, a huge number of smaller sources would become regulated for the first time under the CAA.

[294] Even if one were to determine that this interpretation were the proper reading of the House amendment that would not be the end of the analysis. Instead, that reading would create a conflict between the Senate amendment and the House amendment that would need to be resolved. In that event, the proper resolution of a conflict between the two amendments would be the analysis and conclusion discussed in the Proposed Rule's legal memorandum (discussing EPA's analysis in the CAMR rule at 70 FR 15994, 16029–32): The two amendments must be read together so as to give some effect to each amendment and they are properly read together to provide that, where a source category is regulated under section 112, the EPA may not establish regulations covering the HAP emissions from that source category under section 111(d).

There are a number of reasons why the EPA's interpretation is reasonable and avoids the issues discussed above.

First, the EPA's interpretation reads the House amendment to the Section 112 Exclusion as determining the scope of what air pollutants are to be regulated under CAA section 111(d), as opposed to creating a wholesale exclusion for source categories. The other text in subsections 111(d)(1)(A)(i) and (ii) modify the phrase ''any air pollutant.'' Thus, reading the Section 112 Exclusion to also address the question of what air pollutants may be regulated under CAA section 111(d) is consistent with the overall structure and focus of CAA section 111(d)(1)(A).

Second, the EPA's interpretation furthers—rather than undermines—the purpose of CAA section 111(d) within the long-standing structure of the CAA. That is, this interpretation supports the comprehensive structure for regulating various pollutants from existing sources under the criteria pollutant/NAAQS program under sections 108–110, the HAP program under section 112, and other pollutants under section 111(d), and avoids creating a gap in that structure. See *King* v. *Burwell*, 2015 U.S. LEXIS 4248, *28 (2015)(''A provision that may seem ambiguous in isolation is often clarified by the remainder of the statutory scheme . . . because only one of the permissible meanings produces a substantive effect that is compatible with the rest of the law.'') (quoting *United Sav. Assn. of Tex.* v. *Timbers of Inwood Forest Associates,* Ltd., 484 U. S. 365, 371, 108 S. Ct. 626, 98 L. Ed. 2d 740 (1988)'')

Third, by avoiding the creation of gaps in the statutory structure, the EPA's interpretation is consistent with the legislative history demonstrating that Congress's intent in the 1990 CAA Amendments was to expand the EPA's regulatory authority across the board, compelling the agency to regulate more pollutants, under more programs, more quickly.[295] Conversely, the EPA is aware of no statement in the legislative history indicating that Congress simultaneously sought to restrict the EPA's authority under CAA section 111(d) or to create gaps in the comprehensive structure of the statute. If Congress had intended this amendment to make such a change, one would expect to see some indication of that in the legislative history.

Fourth, when applied in the context of this rule, the EPA's interpretation of the House amendment is consistent with the Senate amendment. Thus, this interpretation avoids creating a conflict within the statute. See discussion above of *Scialabba* v. *Cuellar De Osorio,* 134 S. Ct. 2191 at 2220 (citing and quoting, among other authorities, A. Scalia & B. Garner, Reading Law: The Interpretation of Legal Texts 180 (2012) (''The provisions of a text should be interpreted in a way that renders them compatible, not contradictory. . . . [T]here can be no justification for needlessly rendering provisions in conflict if they can be interpreted harmoniously'')).

In sum, when this interpretation of the House amendment is applied in the context of this rule, the result is that the EPA may promulgate CAA section 111(d) regulations covering carbon dioxide emissions from existing power plants notwithstanding that power plants are regulated for their HAP emissions under CAA section 112.

5. The Two Amendments Are Easily Reconciled and Can Be Given Full Effect

Given that both the House and Senate amendments should be read individually as having the same meaning in the context presented in this rule, giving each amendment full effect is straight-forward: The Section 112 Exclusion in section 111(d) does not foreclose the regulation of non-HAP from a source category regardless of whether that source category is also regulated under CAA section 112. As applied here, the EPA has the authority to promulgate CAA section 111(d) regulations for CO_2 from power plants notwithstanding that power plants are regulated for HAP under CAA section 112.

C. Authority To Regulate EGUs

In a separate, concurrent action, the EPA is also finalizing a CAA section 111(b) rulemaking that regulates CO_2 emissions from new, modified, and reconstructed EGUs. The promulgation of these standards provides the requisite predicate for applicability of CAA section 111(d).

CAA section 111(d)(1) requires the EPA to promulgate regulations under which states must submit state plans regulating ''any existing source'' of certain pollutants ''to which a standard of performance would apply if such existing source were a new source.'' A ''new source'' is ''any stationary source, the construction or modification of which is commenced after the publication of regulations (or, if earlier, proposed regulations) prescribing a standard of performance under [CAA section 111] which will be applicable to such source.'' It should be noted that these provisions make clear that a ''new source'' includes one that undertakes either new construction or a modification. It should also be noted that the EPA's implementing regulations define ''construction'' to include ''reconstruction,'' which the implementing regulations go on to define as the replacement of components of an existing facility to an extent that (i) the fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility, and (ii) it is technologically and economically feasible to meet the applicable standards.

Under CAA section 111(d)(1), in order for existing sources to become subject to that provision, the EPA must promulgate standards of performance under CAA section 111(b) to which, if the existing sources were new sources, they would be subject. Those standards of performance may include standards for sources that undertake new construction, modifications, or reconstructions.

The EPA is finalizing a rulemaking under CAA section 111(b) for CO_2 emissions from affected EGUs concurrently with this CAA section 111(d) rulemaking, which will provide the requisite predicate for applicability of CAA section 111(d).[296]

D. Definition of Affected Sources

For the emission guidelines, an affected EGU is any fossil fuel-fired electric utility steam generating unit (*i.e.,* utility boiler or integrated gasification combined cycle (IGCC) unit) or stationary combustion turbine that was in operation or had commenced

[295] *See* S. Rep. No. 101–228 at 133 (''There is now a broad consensus that the program to regulate hazardous air pollutants . . . should be restructured to provide the EPA with authority to regulate industrial and area sources of air pollution . . . in the near term''), reprinted in 5 *A Legislative History of the Clean Air Act Amendments of 1990* (''Legis. Hist.'') 8338, 8473 (Comm. Print 1993); S. Rep. No. 101–228 at 14 (''The bill gives significant authority to the Administrator in order to overcome the deficiencies in [the NAAQS program]'') & 123 (''Experience with the mobile source provisions in Title II of the Act has shown that the enforcement authorities . . . need to be strengthened and broadened . . .''), reprinted in 5 *Legis. Hist.* at 8354, 8463; H.R. Rep. No. 101–952 at 336–36, 340, 345 & 347 (discussing enhancements to Act's motor vehicle provisions, the EPA's new authority to promulgate chemical accident prevention regulations, the enactment of the Title V permit program, and enhancements to the EPA's enforcement authority), reprinted in 5 *Legis. Hist.* at 1786, 1790, 1795, & 1997.

[296] In the past, the EPA has issued standards of performance under section 111(b) and emission guidelines under section 111(d) simultaneously. *See* ''Standards of Performance for new Stationary Sources and Guidelines for Control of Existing Sources: Municipal Solid Waste Landfills—Final Rule,'' 61 FR 9905 (March 12, 1996).

construction as of January 8, 2014,[297] and that meets the following criteria, which differ depending on the type of unit. To be an affected EGU, such a unit, if it is a fossil fuel-fired electric utility steam generating unit (*i.e.,* a utility boiler or IGCC unit), must serve a generator capable of selling greater than 25 MW to a utility power distribution system and have a base load rating greater than 260 GJ/h (250 MMBtu/h) heat input of fossil fuel (either alone or in combination with any other fuel). If such a unit is a stationary combustion turbine, the unit must meet the definition of a combined cycle or combined heat and power combustion turbine, serve a generator capable of selling greater than 25 MW to a utility power distribution system, and have a base load rating of greater than 260 GJ/h (250 MMBtu/h).

When considering and understanding applicability, the following definitions may be helpful. Simple cycle combustion turbine means any stationary combustion turbine which does not recover heat from the combustion turbine engine exhaust gases for purposes other than enhancing the performance of the stationary combustion turbine itself. Combined cycle combustion turbine means any stationary combustion turbine which recovers heat from the combustion turbine engine exhaust gases to generate steam that is used to create additional electric power output in a steam turbine. Combined heat and power (CHP) combustion turbine means any stationary combustion turbine which recovers heat from the combustion turbine engine exhaust gases to heat water or another medium, generate steam for useful purposes other than exclusively for additional electric generation, or directly uses the heat in the exhaust gases for a useful purpose.

We note that certain affected EGUs are exempt from inclusion in a state plan. Affected EGUs that may be excluded from a state's plan are (1) those units that are subject to subpart TTTT as a result of commencing modification or reconstruction; (2) steam generating units or IGCC units that are currently and always have been subject to a federally enforceable permit limiting net-electric sales to one-third or less of its potential electric output or 219,000 MWh or less on an annual basis; (3) non-fossil units (*i.e.,* units that are capable of combusting 50 percent or more non-fossil fuel) that have historically limited the use of fossil fuels to 10 percent or less of the annual capacity factor or are subject to a federally enforceable permit limiting fossil fuel use to 10 percent or less of the annual capacity factor; (4) stationary combustion turbines that are not capable of combusting natural gas (*i.e.,* not connected to a natural gas pipeline); (5) combined heat and power units that are subject to a federally enforceable permit limiting, or have historically limited, annual net electric sales to a utility power distribution system to the product of the design efficiency and the potential electric output or 219,000 MWh (whichever is greater) or less; (6) units that serve a generator along with other steam generating unit(s), IGCC(s), or stationary combustion turbine(s) where the effective generation capacity (determined based on a prorated output of the base load rating of each steam generating unit, IGCC, or stationary combustion turbine) is 25 MW or less; (7) municipal waste combustor unit subject to subpart Eb of Part 60; or (8) commercial or industrial solid waste incineration units that are subject to subpart CCCC of Part 60.

The rationale for applicability of this final rule is multi-fold. We had proposed that affected EGUs were those existing fossil fuel-fired EGUs that met the applicability criteria for coverage under the final GHG standards for new fossil fuel-fired EGUs being promulgated under section 111(b). However, we are finalizing that States need not include certain units that would otherwise meet the CAA section 111(b) applicability in this CAA section 111(d) emission guidelines. These include simple cycle turbines, certain non-fossil units, and certain combined heat and power units. The final 111(b) standards include applicability criteria for simple cycle combustion turbines, for reasons relating to implementation and minimizing emissions from all future combustion turbines. However, for the following reasons none of the building blocks would result in emission reductions from simple cycle turbines so we are not requiring that States including them in their CAA section 111(d) plans.

First, even more than combined cycle units, simple cycle units have limited opportunities, compared to steam generating units, to reduce their heat rate. Most combustion turbines likely already follow the manufacturer's recommended regular preventive/restorative maintenance for both reliable and efficiency reasons. These regularly scheduled maintenance practices are highly effective methods to maintain heat rates, and additional fleet-wide reductions from simple cycle combustion turbines are likely less than 2 percent. In addition, while approximately one-fifth of overall fossil fuel-fired capacity (GW) consists of simple cycle turbines, these units historically have operated at capacity factors of less than 5 percent and only provide about 1 percent of the fossil fuel-fired generation (GWh). Combustion turbine capacity can therefore only contribute CO_2 emissions amounting to approximately 2 percent of total coal-steam CO_2 emissions. Any single-digit percentage reduction in combustion turbine heat rates would therefore provide less than 1 percent reduction in total fossil-fired CO_2 emissions.

Further, we are not aware of an approach to estimate any limited opportunities that existing simple cycle turbines may have to reduce their heat rate. Similar to coal-steam EGUs, we do not have the unit-specific detailed design information on existing individual simple cycle combustion turbines that is necessary for a detailed assessment of the heat rate improvement potential via best practices and upgrades for each unit. While the EPA could conduct a ''variability analysis'' of simple cycle historical hourly heat rate data (as was done for coal-steam EGUs), the various simple cycle models in use and the historically lower capacity factors of the simple cycle fleet (less run time per start, and more part load operation) would require a simple cycle analysis that includes more complexity and likely more uncertainty than in the coal-steam analysis. Therefore, we do not consider it feasible to estimate potential reductions due to heat rate improvements from simple cycle turbines, and even if it were, we have concluded those reductions would be negligible compared to the reductions from steam generating units. Hence, we do not consider building block 1 as practically applicable to simple cycle units.

Second, the vast majority of simple cycle turbines serve a specific need—providing power during periods of peak electric demand (*i.e.,* peaking units). The existing block of simple cycle turbines are the only units that are able to start fast enough and ramp to full load quickly enough to serve as peaking units. If these units were to be used under building block 2 to displace higher emitting coal-fired units, they would no longer be available to serve as peaking units. Therefore, building block 2 could not be applied to simple cycle

[297] Under Section 111(a) of the CAA, determination of affected sources is based on the date that the EPA proposes action on such sources. January 8, 2014 is the date the proposed GHG standards of performance for new fossil fuel-fired EGUs were published in the **Federal Register** (79 FR 1430).

combustion turbines without jeopardizing grid reliability.

Third, many commenters on the CAA section 111(b) proposal stated that simple cycle turbines will be used to provide backup power to intermittent renewable sources of power such as wind and solar. Consequently, adding additional generation from intermittent renewable sources has the potential to actually increase emissions from simple cycle turbines. Therefore, applying building block 3 based on the capacity of simple cycle turbines would not result in emission reductions from simple cycle combustion turbines. Finally, the EPA expects existing simple cycle turbines to continue to operate as they historically have operated, as peaking units. Including simple cycle turbines in CAA section 111(d) applicability would impact the numerical value of state goals, but it would not impact the stringency of the plans. Such inclusion would increase burden but result in no environmental benefit.

Additionally, under CAA section 111(b) final applicability criteria, new dedicated non-fossil and industrial CHP units are not affected sources if they include permit restrictions on the amount of fossil fuel they burn and the amount of electricity they sell. Such units historically have had no regulatory mandate to include permit requirements limiting the use of fossil fuel or electric sales. We are exempting them from inclusion in CAA section 111(d) state plans in the interest of consistency with CAA section 111(b) and based on their historical fuel use and electric sales.

We discuss changes in applicability of units in relation to state plans in Section VIII of this preamble.

E. Combined Categories and Codification in the Code of Federal Regulations

In this rulemaking, the EPA is combining the listing of sources from the two existing source categories for the affected EGUs, as listed in 40 CFR subpart Da and 40 CFR subpart KKKK, into a single location, 40 CFR subpart UUUU, for purposes of addressing the CO_2 emissions from existing affected EGUs. The EPA is also codifying all of the requirements for the affected EGUs in a new subpart UUUU of 40 CFR part 60 and including all GHG emission guidelines for the affected sources—fossil fuel–fired electric utility steam generating units, as well as stationary combustion turbines—in that newly created subpart.[298]

We believe that combining the emission guidelines for affected sources into a new subpart UUUU is appropriate because the emission guidelines the EPA is establishing do not vary by type of source. Combining the listing of sources into one location, subpart UUUU, will facilitate implementation of CO_2 mitigation measures, such as shifting generation from higher to lower-carbon intensity generation among existing sources (*e.g.,* shifting from utility boilers to NGCC units), and emission trading among sources in the source category.

As discussed in the January 8, 2014 proposal for the CAA section 111(b) standards for GHG emissions from EGUs (79 FR 1430), in 1971 the EPA listed fossil fuel-fired steam generating boilers as a new category subject to section 111 rulemaking, and in 1979 the EPA listed fossil fuel-fired combustion turbines as a new category subject to the CAA section 111 rulemaking. In the ensuing years, the EPA has promulgated standards of performance for the two categories and codified those standards, at various times, in 40 CFR part 60 subparts D, Da, GG, and KKKK.

In the January 8, 2014 proposal, the EPA proposed separate standards of performance for new sources in the two categories and proposed codifying the standards in the same Da and KKKK subparts that currently contain the standards of performance for conventional pollutants from those sources. In addition, the EPA co-proposed combining the two categories into a single category solely for purposes of the CO_2 emissions from new construction of affected EGUs, and codifying the proposed requirements in a new 40 CFR part 60 subpart TTTT. For the final standards of performance for new construction of affected EGUs, the EPA is codifying the final requirements in a new 40 CFR part 60 subpart TTTT.

In this rulemaking, the EPA is combining the two listed source categories into a single source category for purposes of the emission guidelines for the CO_2 emissions from existing affected EGUs. Because the two source categories are pre-existing and the EPA would not be subjecting any additional sources to regulation, the combined source category is not considered a new source category that the EPA must list under CAA section 111(b)(1)(A). As a result, this final rule does not list a new source category under section 111(a)(1)(A), nor does this final rule revise either of the two source categories—fossil fuel—fired electric utility steam generating units and stationary combustion turbines—that the EPA has already listed under that provision. Thus, the EPA is not required to make a finding that the combined source category causes or contributes significantly to air pollution which may reasonably be anticipated to endanger public health or welfare.

[298] The EPA is not codifying any of the requirements of this rulemaking in subparts Da or KKKK.

V. The Best System of Emission Reduction and Associated Building Blocks

In the June 2014 proposal, the EPA proposed to determine that the best system of emission reduction adequately demonstrated (BSER) for reducing CO_2 emissions from existing EGUs was a combination of measures—(1) increasing the operational efficiency of existing coal-fired steam EGUs, (2) substituting increased generation at existing NGCC units for generation at existing steam EGUs, (3) substituting generation from low- and zero-carbon generating capacity for generation at existing fossil fuel-fired EGUs, and (4) increasing demand-side EE to reduce the amount of fossil fuel-fired generation—which we categorized as four ''building blocks.'' As an alternative to the proposed building blocks 2, 3, and 4, the EPA also identified reduced generation in the amount of those building blocks as part of the BSER. These measures are not the only approaches EGUs can take to reduce CO_2, but are those that the EPA felt best met the statutory criteria. We solicited comment on all aspects of our BSER determination, including a broad array of other approaches. We have considered thoroughly the extensive comments submitted on a variety of topics related to the BSER and the individual building blocks, along with our own continued analysis, and we are finalizing the BSER based on the first three building blocks, with certain refinements.

Consistent with the approach taken in the proposed rule, in determining the BSER we have taken account of the unique characteristics of CO_2 pollution, particularly its global nature, huge quantities, and the limited means for controlling it; and the unique characteristics of the source category, particularly the exceptional degree of interconnectedness among individual affected EGUs and the longstanding practice of coordinating planning and operations across multiple sources, reflecting the fact that each EGU's function is interdependent with the function of other EGUs. Each building block is a proven approach for reducing emissions from the affected source category that is appropriate in this pollutant- and industry-specific context. The BSER also encompasses a variety of measures or actions that individual affected EGUs could take to implement the building blocks, including (i) direct investment in efficiency improvements and in lower- and zero-carbon generation, (ii) cross-investment in these activities through mechanisms such as emissions trading approaches, where the state-established standards of performance to which sources are subject incorporate such approaches, and (iii) reduction of higher-carbon generation.

With attention to emission reduction costs, electricity rates, and the importance of ensuring continued reliability of electricity supplies, the individual building blocks and the overall BSER have been defined not at the maximum possible degree of stringency but at a reasonable degree of stringency designed to appropriately balance consideration of the various BSER factors. Additional, non-building block-specific aspects of the BSER quantification methodology discussed below are similarly mindful of these considerations. This approach to determination of the BSER provides compliance headroom that ensures that the emission limitations reflecting the BSER are achievable by the source category, but nevertheless, as required by the CAA, will result in meaningful reductions in CO_2 emissions from this sector. The wide range of actions encompassed in the building blocks, and a further wide range of possible emissions-reducing actions not included in the BSER but nevertheless available to help with compliance, ensure that those emission limitations are achievable by individual affected EGUs as well.

The final BSER incorporates certain changes from the proposed rule, reflecting the EPA's consideration of comments responding to the approaches outlined in the proposal and our own further analysis. The principal changes are the exclusion from the BSER of emission reductions achievable through demand-side EE and through nuclear generation; a revised approach to determination of emission reductions achievable through increased RE generation; a consistent approach to determination of emission reductions achievable through all the building blocks that better reflects the regional nature of the electricity system and entails separate analyses for the Eastern, Western, and Texas Interconnections; and a revised interim goal period of 2022 to 2029 (instead of the proposed interim period of 2020 to 2029). These changes to the BSER and the building blocks are discussed in more detail later in this section of the preamble.

Also, to address concerns identified in the proposal and the October 30, 2014 NODA and in response to associated comments, in the final rule we have represented the emission limitations achievable through the BSER in the form of uniform CO_2 emission performance rates for each of two affected source subcategories: Steam generating units and stationary combustion turbines. However, like the proposed rule, the final rule also provides weighted-average state-specific goals that a state may choose as an alternative method for complying with its obligation to set standards of performance for its affected EGUs—an alternative, that is, to adopting the nationwide subcategory-based CO_2 emission performance rates as the standard of performance for its affected EGUs. The reformulation of the emission limitations as uniform CO_2 emission performance rates is discussed in this section and in section VI of the preamble, and the relation of the performance rates to the state-specific goals and states' section 111(d) plan options is discussed in sections VII and VIII of the preamble.

Section V.A. describes our determination of the final BSER, including a discussion of the associated emissions performance level, and provides the rationale for our determination. In section V.B. we address certain legal issues in greater detail, including key issues raised in comments. Sections V.C. through V.E. contain more detailed discussions of the three individual building blocks included in the final BSER. Further information can be found in the GHG Mitigation Measures TSD for the CPP Final Rule, the CO_2 Emission Performance Rate and Goal Computation TSD for the CPP Final Rule, the Response to Comments document, and, about certain topics, the Legal Memorandum for the Clean Power Plan Final Rule, all of which are available in the docket.

A. The Best System of Emission Reduction

This section sets forth our determination of the BSER for reducing CO_2 emissions from existing EGUs, including a discussion of the associated emissions performance level, and the rationale for that determination. In section V.A.1., we describe the legal framework for determination of the BSER in general. Section V.A.2. summarizes the determination of the BSER for this rule. In section V.A.3., we discuss changes from the proposal. Section V.A.4. provides more detail on our determination of the BSER, including our determinations regarding the individual elements of the BSER, as applied to the two subcategories of fossil steam units and combustion turbines. In section V.A.5., we explain the specific actions that individual affected EGUs in the two subcategories may take to implement the building blocks and thereby achieve the EPA-identified source subcategory-specific emission performance rates that, in turn, form the basis for the standards of performance that states must set. Because these actions implement the building blocks, they may be understood as part of the BSER. In this discussion, we recognize that states can choose to set sources' standards of performance in different forms and that the form of the standard affects how various types of actions can be used to comply with the standard. In section V.A.6., we discuss the substantial compliance flexibility provided by additional measures, not included in the BSER, that individual affected EGUs can use to achieve their standards of performance. Finally, section V.A.7. addresses the severability of the building blocks.

1. Legal Requirements for BSER in the Emission Guidelines

a. *Introduction.* In the June 2014 proposal for this rule, we described the principal legal requirements for standards of performance under CAA section 111(d)(1) and (a)(1). We based our description in part on our discussion of the legal requirements for standards of performance under CAA section 111(b) and (a)(1), which we included in the January 2014 proposal for standards of performance for CO_2 emissions from new fossil fuel-fired EGUs. In the latter proposal, we noted that the D.C. Circuit has handed down numerous decisions that interpret CAA section 111(a)(1), including its component elements, and we reviewed that case law in detail.[299]

We received comments on our proposed interpretation, and in light of those comments, in this final rule, we are clarifying our interpretation in certain respects. We discuss our interpretation below.[300]

[299] 79 FR 1430, 1462 (January 8, 2014).

[300] We also discuss our interpretation of the requirements for standards of performance and the BSER under section 111(b), for new sources, in the section 111(b) rulemaking that the EPA is finalizing simultaneously with this rule and in the Legal Memorandum for this rule. Our interpretations of

b. *CAA requirements and court interpretation.*[301] Section 111(d)(1) directs the EPA to promulgate regulations establishing a section 110-like procedure under which states submit state plans that establish ''standards of performance'' for emissions of certain air pollutants from sources which, if they were new sources, would be regulated under section 111(b), and that implement and enforce those standards of performance.

The term ''standard of performance'' is defined to mean—

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

Section 111(a)(1).

These provisions authorize the EPA to determine the BSER for the affected sources and, based on the BSER, to establish emission guidelines that identify the minimum amount of emission limitation that a state, in its state plan, must impose on its sources through standards of performance. Consistent with these CAA requirements, the EPA's regulations require that the EPA's guidelines reflect—

the degree of emission reduction achievable through the application of the best system of emission reduction which (taking into account the cost of such reduction) the Administrator has determined has been adequately demonstrated.[302]

The EPA's approach in this rulemaking is to determine the BSER on a source subcategory-wide basis, to determine the emission limitation that results from applying the BSER to the sources in the subcategory, and then to establish emission guidelines for the states that incorporate those emission limitations. The EPA expresses these emission limitations in the form of emission performance rates, and they must be achievable by the source subcategory through the application of the BSER.

Following the EPA's promulgation of emission guidelines, each state must determine the standards of performance for its sources, which the EPA's regulations call ''designated facilities.''[303] A state has broad discretion in doing so. CAA section 111(d)(1) requires the EPA's regulations to ''permit the State in applying a standard of performance to any particular source . . . to take into consideration, among other factors, the remaining useful life of the . . . source. . .''[304] In addition, under CAA section 116, the state is authorized to set a standard of performance for any particular source that is more stringent than the emission limit contained in the EPA's emission guidelines.[305] Thus, for any particular source, a state may apply a standard of performance that is either more stringent or less stringent than the performance level in the emission guidelines, as long as, in total, the state's sources achieve at least the same degree of emission limitation as included in the EPA's emission guidelines. The states must include the standards of performance in their state plans and submit the plans to the EPA for review.[306] Under CAA section 111(d)(2)(A), the EPA approves state plans as long as they are ''satisfactory.''

As noted in the January 2014 proposal and discussed in more detail above under section II.G, Congress first included the definition of ''standard of performance'' when enacting CAA section 111 in the 1970 Clean Air Act Amendments (CAAA), amended it in the 1977 CAAA, and then amended it again in the 1990 CAAA to largely restore the definition as it read in the 1970 CAAA. It is in the legislative history for the 1970 and 1977 CAAA that Congress primarily addressed the definition as it read at those times and that legislative history provides guidance in interpreting this provision.[307] In addition, although the D.C. Circuit has never reviewed a section 111(d) rulemaking, the Court has reviewed section 111(b) rulemakings on numerous occasions during the past 40 years, handing down decisions dated from 1973 to 2011,[308] through which the Court has developed a body of case law that interprets the term ''standard of performance.''

c. *Key elements of interpretation.* The emission guidelines promulgated by the Administrator must include emission limitations that are ''achievable'' by the source category by application of a ''system of emission reduction'' that is ''adequately demonstrated'' and that the EPA determines to be the ''best,''

these requirements in the two rules are generally consistent except to the extent that they reflect distinctions between new and existing sources. For example, as discussed in the section 111(b) rule, the legislative history indicates that Congress intended that the BSER for new industrial facilities, which were expected to have lengthy useful lives, would include the most advanced pollution controls available, but Congress had a broader conception of the BSER for existing facilities.

[301] Our interpretation of the CAA provisions at issue is guided by *Chevron U.S.A. Inc.* v. *NRDC,* 467 U.S. 837, 842–43 (1984). In *Chevron,* the U.S. Supreme Court set out a two-step process for agency interpretation of statutory requirements: the agency must, at step 1, determine whether Congress's intent as to the specific matter at issue is clear, and, if so, the agency must give effect to that intent. If congressional intent is not clear, then, at step 2, the agency has discretion to fashion an interpretation that is a reasonable construction of the statute.

[302] 40 CFR 60.21(e). This definition was promulgated as part of the EPA's CAA 111(d) implementing regulations and was not updated to reflect the textual changes adopted by Congress in 1977. That said, Congress recognized that those changes ''merely make[] explicit what was implicit in the previous language.'' H.R. Rep. No. 95–294, at 190 (May 12, 1977).

[303] 40 CFR 60.24(b)(3).

[304] The EPA's regulations, promulgated prior to enactment of the ''remaining useful life'' provision of section 111(d)(1), provide: ''Unless otherwise specified in the applicable subpart on a case-by-case basis for particular designated facilities, or classes of facilities, States may provide for the application of less stringent emission standards or longer compliance schedules than those otherwise required'' by the corresponding emission guideline. 40 CFR 60.24(f). Some of the factors that a state may consider for this case-by-case analysis include the ''cost of control resulting from plant age, location, or basic process design'' and the ''physical impossibility of installing necessary control equipment,'' among other factors ''that make application of a less stringent standard or final compliance time significantly more reasonable.'' *Id.*

[305] In addition, CAA section 116 authorizes the state to set standards of performance for all of its sources that, together, are more stringent than the EPA's emission guidelines.

[306] 40 CFR 60.23.

[307] In the 1970 CAAA, Congress defined ''standard of performance,'' under § 111(a)(1), as:

a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction) the Administrator determines has been adequately demonstrated.

In the 1977 CAAA, Congress revised the definition to distinguish among different types of sources, and to require that for fossil fuel-fired sources, the standard (i) be based on, in lieu of the ''best system of emission reduction . . . adequately demonstrated,'' the ''best technological system of continuous emission reduction . . . adequately demonstrated;'' and (ii) require a percentage reduction in emissions. In addition, in the 1977 CAAA, Congress expanded the parenthetical requirement that the Administrator consider the cost of achieving the reduction to also require the Administrator to consider ''any nonair quality health and environmental impact and energy requirements.''

In the 1990 CAAA, Congress again revised the definition, this time repealing the requirements that the standard of performance be based on the best technological system and achieve a percentage reduction in emissions, and replacing those provisions with the terms used in the 1970 CAAA version of § 111(a)(1) that the standard of performance be based on the ''best system of emission reduction . . . adequately demonstrated.'' This 1990 CAAA version is the current definition, which is applicable at present. Even so, because parts of the definition as it read under the 1977 CAAA were retained in the 1990 CAAA, the explanation in the 1977 CAAA legislative history, and the interpretation, in the case law, of those parts of the definition remain relevant to the definition as it reads today.

[308] *Portland Cement Ass'n* v. *Ruckelshaus,* 486 F.2d 375 (D.C. Cir. 1973); *Essex Chemical Corp.* v. *Ruckelshaus,* 486 F.2d 427, (D.C. Cir. 1973); *Portland Cement Ass'n* v. *EPA,* 665 F.3d 177 (D.C. Cir. 2011). *See also Delaware* v. *EPA,* No. 13–1093 (D.C. Cir. May 1, 2015).

''taking into account'' the factors of ''cost . . . nonair quality health and environmental impact and energy requirements.'' The D.C. Circuit has stated that in determining the ''best'' system, the EPA must also take into account ''the amount of air pollution'' [309] reduced and the role of ''technological innovation.'' [310] The Court has emphasized that the EPA has discretion in weighing those various factors.[311] [312]

Our overall approach to determining the BSER and emission guidelines, which incorporates the various elements, is as follows: In developing an emission guideline, we generally engage in an analytical approach that is similar to what we conduct under CAA section 111(b) for new sources. First, we identify ''system[s] of emission reduction'' that have been ''adequately demonstrated'' for a particular source category. Second, we determine the ''best'' of these systems after evaluating the amount of reductions, costs, any nonair health and environmental impacts, energy requirements, and, in the alternative, the advancement of technology (that is, we apply a formulation of the BSER with the above noted factors, and then, in the alternative, we apply a formulation of the BSER with those same factors plus the advancement of technology). And third, we select an achievable emission limit—here, the emission performance rates—based on the BSER.[313] In contrast to subsection (b), however, subsection (d)(1) assigns to the states, not the EPA, the obligation of setting standards of performance for the affected sources. As discussed below in the following subsection, in examining the range of reasonable options for states to consider in setting standards of performance under these guidelines, we identified a number of considerations, including the interconnected operations of the affected sources and the characteristics of the CO_2 pollutant.

The remainder of this subsection discusses the various elements in our general analytical approach.

(1) System of Emission Reduction

As we discuss below, the CAA does not define the phrase ''system of emission reduction.'' The ordinary, everyday meaning of ''system'' is a set of things or parts forming a complex whole; a set of principles or procedures according to which something is done; an organized scheme or method; and a group of interacting, interrelated, or interdependent elements.[314] With this definition, the phrase ''system of emission reduction'' takes a broad meaning: a set of measures that work together to reduce emissions. The EPA interprets this phrase to carry an important limitation: Because the emission guidelines for the existing sources must reflect ''the degree of emission limitation achievable *through the application of* the best system of emission reduction . . . adequately demonstrated,'' the system must be limited to measures that can be implemented—''appl[ied]''—by the sources themselves, that is, as a practical matter, by actions taken by the owners or operators of the sources. As we discuss below, this definition is sufficiently broad to include the building blocks.

(2) ''Adequately Demonstrated''

Under section 111(a)(1), in order for a ''system of emission reduction'' to serve as the basis for an ''achievable'' emission limitation, the Administrator must determine that the system is ''adequately demonstrated.'' This means, according to the D.C. Circuit, that the system is ''one which has been shown to be reasonably reliable, reasonably efficient, and which can reasonably be expected to serve the interests of pollution control without becoming exorbitantly costly in an economic or environmental way.'' [315] It does not mean that the system ''must be in actual routine use somewhere.'' [316] Rather, the Court has said, ''[t]he Administrator may make a projection based on existing technology, though that projection is subject to the restraints of reasonableness and cannot be based on 'crystal ball' inquiry.'' [317] Similarly, the EPA may ''hold the industry to a standard of improved design and operational advances, so long as there is substantial evidence that such improvements are feasible.'' [318] Ultimately, the analysis ''is partially dependent on 'lead time,''' that is, ''the time in which the technology will have to be available.'' [319] Unlike for CAA section 111(b) standards that are applicable immediately after the effective date of their promulgation, under CAA section 111(e), compliance with CAA section 111(d) standards may be set sometime in the future. This is due, in part, to the period of time for states to submit state plans and for the EPA to act on them.

(3) ''Best''

In determining which adequately demonstrated system of emission reduction is the ''best,'' the EPA considers the following factors:

(a) Costs

Under CAA section 111(a)(1), the EPA is required to take into account ''the cost of achieving'' the required emission reductions. As described in the January 2014 proposal,[320] in several cases the D.C. Circuit has elaborated on this cost factor and formulated the cost standard in various ways, stating that the EPA may not adopt a standard the cost of which would be ''exorbitant,'' [321] ''greater than the industry could bear and survive,'' [322] ''excessive,'' [323] or ''unreasonable.'' [324] These formulations appear to be synonymous, and for convenience, in this rulemaking, we will use reasonableness as the standard,

[309] *See Sierra Club* v. *Costle,* 657 F.2d 298, 326 (D.C. Cir. 1981).

[310] *See Sierra Club* v. *Costle,* 657 F.2d at 347.

[311] *See Lignite Energy Council* v. *EPA,* 198 F.3d 930, 933 (D.C. Cir. 1999).

[312] Although CAA section 111(a)(1) may be read to state that the factors enumerated in the parenthetical are part of the ''adequately demonstrated'' determination, the D.C. Circuit's case law appears to treat them as part of the ''best'' determination. *See Sierra Club* v. *Costle,* 657 F.2d at 330 (recognizing that CAA section 111 gives the EPA authority ''when determining the best technological system to weigh cost, energy, and environmental impacts''). Nevertheless, it does not appear that those two approaches would lead to different outcomes. *See, e.g., Lignite Energy Council* v. *EPA,* 198 F.3d at 933 (rejecting challenge to the EPA's cost assessment of the ''best demonstrated system''). In this rule, the EPA treats the factors as part of the ''best'' determination, but, as noted, even if the factors were part of the ''adequately demonstrated'' determination, our analysis and outcome would be the same.

[313] *See, e.g.,* Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air pollutants Reviews, 77 FR 49490, 49494 (Aug. 16, 2012) (describing the three-step analysis in setting a standard of performance).

[314] *Oxford Dictionary of English* (3rd ed.) (2010), *available at http://www.oxforddictionaries.com/us/definition/american_english/system; see also* American Heritage Dictionary (5th ed.) (2013), *available at http://www.yourdictionary.com/system#americanheritage*; and *The American College Dictionary (C.L. Barnhart, ed. 1970) (''an assemblage or combination of things or parts forming a complex or unitary whole'').*

[315] *Essex Chem. Corp.* v. *Ruckelshaus,* 486 F.2d 427, 433 (D.C. Cir. 1973), *cert. denied,* 416 U.S. 969 (1974).

[316] *Portland Cement Ass'n* v. *Ruckelshaus,* 486 F.2d 375, 391 (D.C. Cir. 1973) (citations omitted) (discussing the Senate and House bills and reports from which the language in CAA section 111 grew).

[317] Ibid.

[318] *Sierra Club* v. *Costle,* 657 F.2d 298, 364 (1981).

[319] *Portland Cement Ass'n* v. *Ruckelshaus,* 486 F.2d 375, 391 (D.C. Cir. 1973) (citations omitted).

[320] 79 FR 1430, 1464 (January 8, 2014).

[321] *Lignite Energy Council* v. *EPA,* 198 F.3d 930, 933 (D.C. Cir. 1999).

[322] *Portland Cement Ass'n* v. *EPA,* 513 F.2d 506, 508 (D.C. Cir. 1975).

[323] *Sierra Club* v. *Costle,* 657 F.2d 298, 343 (D.C. Cir. 1981).

[324] *Sierra Club* v. *Costle,* 657 F.2d 298, 343 (D.C. Cir. 1981).

so that a control technology may be considered the ''best system of emission reduction . . . adequately demonstrated'' if its costs are reasonable, but cannot be considered the best system if its costs are unreasonable.[325] [326]

The D.C. Circuit has repeatedly upheld the EPA's consideration of cost in reviewing standards of performance. In several cases, the Court upheld standards that entailed significant costs, consistent with Congress's view 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.'' [327] *See Essex Chemical Corp.* v. *Ruckelshaus,* 486 F.2d 427, 440 (D.C. Cir. 1973); [328] *Portland Cement Association* v. *Ruckelshaus,* 486 F.2d 375, 387–88 (D.C. Cir. 1973); *Sierra Club* v. *Costle,* 657 F.2d 298, 313 (D.C. Cir. 1981) (upholding standard imposing controls on SO_2 emissions from coal-fired power plants when the ''cost of the new controls . . . is substantial'').[329]

As discussed below, the EPA may consider costs on both a source-specific basis and a sector-wide, regional, or nationwide basis.

(b) Non-Air Health and Environmental Impacts

Under CAA section 111(a)(1), the EPA is required to take into account ''any nonair quality health and environmental impact'' in determining the BSER. As the D.C. Circuit has explained, this requirement makes explicit that a system cannot be ''best'' if it does more harm than good due to cross-media environmental impacts.[330]

(c) Energy Considerations

Under CAA section 111(a)(1), the EPA is required to take into account ''energy requirements.'' As discussed below, the EPA may consider energy requirements on both a source-specific basis and a sector-wide, region-wide, or nationwide basis. Considered on a source-specific basis, ''energy requirements'' entails, for example, the impact, if any, of the system of emission reduction on the source's own energy needs.

(d) Amount of Emissions Reductions

In the proposed rulemakings for this rule and the associated section 111(b) rule, we noted that although the definition of ''standard of performance'' does not by its terms identify the amount of emissions from the category of sources or the amount of emission reductions achieved as factors the EPA must consider in determining the ''best system of emission reduction,'' the D.C. Circuit has stated that the EPA must do so. *See Sierra Club* v. *Costle,* 657 F.2d 298, 326 (D.C. Cir. 1981) (''we can think of no sensible interpretation of the statutory words ''best . . . system'' which would not incorporate the amount of air pollution as a relevant factor to be weighed when determining the optimal standard for controlling . . . emissions'').[331] The fact that the purpose of a ''system of emission reduction'' is to reduce emissions, and that the term itself explicitly incorporates the concept of reducing emissions, supports the Court's view that in determining whether a ''system of emission reduction'' is the ''best,'' the EPA must consider the amount of emission reductions that the system would yield. Even if the EPA were not required to consider the amount of emission reductions, the EPA has the discretion to do so, on grounds that either the term ''system of emission reduction'' or the term ''best'' may reasonably be read to allow that discretion.

(e) Sector- or Nationwide Component of Factors in Determining the BSER

As discussed in the January 2014 proposal for the section 111(b) rulemaking and the proposal for this rulemaking, another component of the D.C. Circuit's interpretations of CAA section 111 is that the EPA may consider the various factors it is required to consider on a national or regional level and over time, and not only on a plant-specific level at the time of the rulemaking.[332] The D.C. Circuit based this interpretation—which it made in the 1981 *Sierra Club* v. *Costle* case, which concerned the NSPS for new power plants—on a review of the legislative history, stating,

> [T]he Reports from both Houses on the Senate and House bills illustrate very clearly that Congress itself was using a long-term lens with a broad focus on future costs, environmental and energy effects of different technological systems when it discussed section 111.[333]

The Court has upheld EPA rules that the EPA ''justified . . . in terms of the policies of the Act,'' including balancing long-term national and regional impacts:

> The standard reflects a balance in environmental, economic, and energy consideration by being sufficiently stringent to bring about substantial reductions in SO_2 emissions (3 million tons in 1995) yet does so at reasonable costs without significant energy penalties . . . . By achieving a balanced coal demand within the utility sector and by promoting the development of less expensive SO_2 control technology, the final standard will expand environmentally acceptable energy supplies to existing power plants and industrial sources.
>
> By substantially reducing SO_2 emissions, the standard will enhance the potential for long term economic growth at both the national and regional levels.[334]

In this rule, the EPA is considering costs and energy implications on the

[325] These cost formulations are consistent with the legislative history of section 111. 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.

[326] We received comments that we do not have authority to revise the cost standard as established in the case law, *e.g.,* ''exorbitant,'' ''excessive,'' etc., to a ''reasonableness'' standard that the commenters considered less protective of the environment. We agree that we do not have authority to revise the cost standard as established in the case law, and we are not attempting to do so here. Rather, our description of the cost standard as ''reasonableness'' is intended to be a convenient term for referring to the cost standard as established in the case law.

[327] 1977 House Committee Report at 184.

[328] The costs for these standards were described in the rulemakings. *See* 36 FR 24876 (December 23, 1971), 37 FR 5767, 5769 (March 21, 1972).

[329] Indeed, in upholding the EPA's consideration of costs under other provisions requiring consideration of cost, courts have also noted the substantial discretion delegated to the EPA to weigh cost considerations with other factors. *Chemical Mfr's Ass'n* v. *EPA,* 870 F. 2d 177, 251 (5th Cir. 1989); Am. Iron & *Steel Inst.* v. *EPA,* 526 F. 2d 1027, 1054 (3d Cir. 1975); *Ass'n of Pacific Fisheries* v. *EPA,* 615 F. 2d 794, 808 (9th Cir. 1980).

[330] *Portland Cement* v. *EPA,* 486 F. 2d at 384; *Sierra Club* v. *Costle,* 657 F. 2d at 331; *see also Essex Chemical Corp.* v. *Ruckelshaus,* 486 F. 2d at 439 (remanding standard to consider solid waste disposal implications of the BSER determination).

[331] *Sierra Club* v. *Costle,* 657 F.2d 298 (D.C. Cir. 1981) was governed by the 1977 CAAA version of the definition of ''standard of performance,'' which revised the phrase ''best system of emission reduction'' to read, ''best technological system of continuous emission reduction.'' As noted above, the 1990 CAAA deleted ''technological'' and ''continuous'' and thereby returned the phrase to how it read under the 1970 CAAA. The court's interpretation of the 1977 CAAA phrase in *Sierra Club* v. *Costle* to require consideration of the amount of air emissions remains valid for the 1990 CAAA phrase ''best system of emission reduction.''

[332] 79 FR 1430, 1465 (January 8, 2014) (citing *Sierra Club* v. *Costle,* 657 F.2d at 351).

[333] *Sierra Club* v. *Costle,* 657 F.2d at 331 (citations omitted) (citing legislative history).

[334] *Sierra Club* v. *Costle,* 657 F.2d at 327–28 (quoting 44 FR at 33583/3–33584/1). In the January 2014 proposal, we explained that although the D.C. Circuit decided *Sierra Club* v. *Costle* before the *Chevron* case was decided in 1984, the D.C. Circuit's decision could be justified under either *Chevron* step 1 or 2. 79 FR 1430, 1466 (January 8, 2014).

basis of (i) their source-specific impacts and (ii) a sector-wide, regional, or national basis, both separately and in combination with each other.

(4) Achievability of the Emission Limitation in the Emission Guidelines

Before discussing the requirement under section 111(d) that the emission limitation in the emission guidelines must be ''achievable,'' it is useful to discuss the comparable requirement under section 111(b) for new sources. For new sources, CAA section 111(b)(1)(B) and (a)(1) provides that the EPA must establish ''standards of performance,'' which are standards for emissions that reflect the degree of emission limitation that is ''achievable'' through the application of the BSER. According to the D.C. Circuit, a standard of performance is ''achievable'' if a technology can reasonably be projected to be available to an individual source at the time it is constructed that will allow it to meet the standard.[335] Moreover, according to the Court, ''[a]n achievable standard is one which is within the realm of the adequately demonstrated system's efficiency and which, while not at a level that is purely theoretical or experimental, need not necessarily be routinely achieved within the industry prior to its adoption.''[336] To be achievable, a standard ''must be capable of being met under most adverse conditions which can reasonably be expected to recur and which are not or cannot be taken into account in determining the 'costs' of compliance.''[337] To show a standard is achievable, the EPA must ''(1) identify variable conditions that might contribute to the amount of expected emissions, and (2) establish that the test data relied on by the agency are representative of potential industry-wide performance, given the range of variables that affect the achievability of the standard.''[338]

The D.C. Circuit established these standards for achievability in cases concerning CAA section 111(b) new source standards of performance. There is no case law under CAA section 111(d). Assuming that those standards for achievability apply under section 111(d), in this rulemaking, we are taking a similar approach for the emission limitation that the EPA identifies in the emission guidelines. For existing sources, section 111(d)(1) requires the EPA to establish requirements for state plans that, in turn, must include ''standards of performance.'' Through long-standing regulations[339] and consistent practice, the EPA has interpreted this provision to require the EPA to promulgate emission guidelines that determine the BSER for a source category and that identify the amount of emission limitation achievable by application of the BSER.

The EPA has promulgated these emission guidelines on the basis that the existing sources can achieve the limitation, even though the state retains discretion to apply standards of performance to individual sources that are more or less stringent.

As indicated in the proposed rulemakings for this rule and the associated section 111(b) rule, the requirement that the emission limitation in the emission guidelines be ''achievable'' based on the ''best system of emission reduction . . . adequately demonstrated'' indicates that the technology or other measures that the EPA identifies as the BSER must be technically feasible. *See* 79 FR 1430, 1463 (January 8, 2014). At least in some cases, in determining whether the emission limitation is achievable, it is useful to analyze the technical feasibility of the system of emission reduction, and we do so in this rulemaking.

(5) Expanded Use and Development of Technology

The D.C. Circuit has long held that Congress intended for CAA section 111 to create incentives for new technology and therefore that the EPA is required to consider technological innovation as one of the factors in determining the ''best system of emission reduction.'' *See Sierra Club* v. *Costle,* 657 F.2d at 346–47. The Court has grounded its reading in the statutory text.[340] In addition, the Court's interpretation finds firm support in the legislative history.[341] The legislative history identifies three different ways that Congress designed CAA section 111 to authorize standards of performance that promote technological improvement: (i) The development of technology that may be treated as the ''best system of emission reduction . . . adequately demonstrated;'' under section 111(a)(1);[342] (ii) the expanded use of the best demonstrated technology;[343] and (iii) the development of emerging technology.[344] Even if the EPA were not required to consider technological innovation as part of its determination of the BSER, it would be reasonable for the EPA to consider it, either because technological innovation may be considered an element of the term ''best,'' or because the term ''best system of emission reduction'' is ambiguous as to whether technological innovation may be considered, and it is reasonable for the EPA to interpret it to authorize consideration of technological innovation in light of Congress's emphasis on technological innovation.

In any event, as discussed below, the EPA may justify the control measures identified in this rule as the BSER even without considering the factor of incentivizing technological innovation or development.

(6) EPA Discretion

The D.C. Circuit has made clear that the EPA has broad discretion in determining the appropriate standard of performance under the definition in CAA section 111(a)(1), quoted above. Specifically, in *Sierra Club* v. *Costle,* 657 F.2d 298 (D.C. Cir. 1981), the Court explained that ''section 111(a) explicitly instructs the EPA to balance multiple concerns when promulgating a

[335] *Sierra Club* v. *Costle,* 657 F.2d 298, 364, n. 276 (D.C. Cir. 1981).

[336] *Essex Chem. Corp.* v. *Ruckelshaus,* 486 F.2d 427, 433–34 (D.C. Cir. 1973), *cert. denied,* 416 U.S. 969 (1974).

[337] *Nat'l Lime Ass'n* v. *EPA,* 627 F.2d 416, 433, n.46 (D.C. Cir. 1980).

[338] *Sierra Club* v. *Costle,* 657 F.2d 298, 377 (D.C. Cir. 1981) (citing *Nat'l Lime Ass'n* v. *EPA,* 627 F.2d 416 (D.C. Cir. 1980). In considering the representativeness of the source tested, the EPA may consider such variables as the '''feedstock, operation, size and age' of the source.'' *Nat'l Lime Ass'n* v. *EPA,* 627 F.2d 416, 433 (D.C. Cir. 1980). Moreover, it may be sufficient to ''generalize from a sample of one when one is the only available sample, or when that one is shown to be representative of the regulated industry along relevant parameters.'' *Nat'l Lime Ass'n* v. *EPA,* 627 F.2d 416, 434, n.52 (D.C. Cir. 1980).

[339] 40 CFR 60.21(e).

[340] *Sierra Club* v. *Costle,* 657 F. 2d at 346 (''Our interpretation of section 111(a) is that the mandated balancing of cost, energy, and nonair quality health and environmental factors embraces consideration of technological innovation as part of that balance. The statutory factors which EPA must weigh are broadly defined and include within their ambit subfactors such as technological innovation.'').

[341] *See* S. Rep. No. 91–1196 at 16 (1970) (''Standards of performance should provide an incentive for industries to work toward constant improvement in techniques for preventing and controlling emissions from stationary sources''); S. Rep. No. 95–127 at 17 (1977) (cited in *Sierra Club* v. *Costle,* 657 F.2d at 346 n. 174) (''The section 111 Standards of Performance . . . sought to assure the use of available technology and to stimulate the development of new technology'').

[342] *See Portland Cement Ass'n* v. *Ruckelshaus,* 486 F.2d 375, 391 (D.C. Cir. 1973) (the best system of emission reduction must ''look[ ] toward what may fairly be projected for the regulated future, rather than the state of the art at present'').

[343] *See* 1970 Senate Committee Report No. 91–1196 at 15 (''The maximum use of available means of preventing and controlling air pollution is essential to the elimination of new pollution problems'').

[344] *See Sierra Club* v. *Costle,* 657 F.2d at 351 (upholding a standard of performance designed to promote the use of an emerging technology).

NSPS,'' [345] and emphasized that ''[t]he text gives the EPA broad discretion to weigh different factors in setting the standard.'' [346] In *Lignite Energy Council* v. *EPA,* 198 F.3d 930 (D.C. Cir. 1999), the Court reiterated:

> Because section 111 does not set forth the weight that should be assigned to each of these factors, we have granted the agency a great degree of discretion in balancing them. . . . EPA's choice [of the 'best system'] will be sustained unless the environmental or economic costs of using the technology are exorbitant. . . . EPA [has] considerable discretion under section 111.[347]

d. *Approach to the source category and subcategorizing.* Section 111 requires the EPA first to list source categories that may reasonably be expected to endanger public health or welfare and then to regulate new sources within each such source category. Section 111(b)(2) grants the EPA discretion whether to ''distinguish among classes, types, and sizes within categories of new sources for the purpose of establishing [new source] standards,'' which we refer to as ''subcategorizing.'' Section 111(d)(1), in conjunction with section 111(a)(1), simply requires the EPA to determine the BSER, does not prescribe the method for doing so, and is silent as to whether the EPA may subcategorize. The EPA interprets this provision to authorize the EPA to exercise discretion as to whether and, if so, how to subcategorize. In addition, the regulations under CAA section 111(d) provide that the Administrator will specify different emission guidelines or compliance times or both ''for different sizes, types, and classes of designated facilities when costs of the control, physical limitations, geographical location, or similar factors make subcategorization appropriate.'' [348]

As with any of its own regulations, the EPA has authority to interpret or revise these regulations.

Of course, regardless of whether the EPA subcategorizes within a source category for purposes of determining the BSER and the emissions performance level for the emission guideline, as part of its CAA section 111(d) plan, a state retains great flexibility in assigning standards of performance to its affected EGUs. Thus, the state may, if it wishes, impose different emission reduction obligations on different sources, as long as the overall level of emission limitation is at least as stringent as the emission guidelines.

2. The BSER for This Rule—Overview

a. *Summary.* This section describes the EPA's overall approach to establishing the BSER. This rule, promulgated under CAA section 111(d), establishes emission guidelines for states to use in establishing standards of performance for affected EGUs, and the BSER is the central determination that the EPA must make in formulating the guidelines. In order to establish the BSER we have considered the subcategory of the steam affected EGUs as a whole, and the subcategory of the combustion turbine affected EGUs as a whole, and have identified the BSER for each subcategory as the measures that the sources, viewed together and operating under the standards of performance established for them by the states, can implement to reduce their emissions to an appropriate amount, and that meet the other requirements for the BSER including, for example, cost reasonableness.[349] After identifying the BSER in this manner, the EPA determines the performance levels—in this case, the CO_2 emission performance rates—for the steam generators and for the combustion turbines.

In establishing the BSER the EPA also considered the set of actions that an EGU, operating under a standard of performance established by its state, may take to achieve the applicable performance rate, if the state adopts that rate as the standard of performance and applies it to the EGUs in its jurisdiction, or to achieve the equivalent mass-based limit, and that meet the other requirements for the BSER. These actions implement the BSER and may therefore be understood as part of the BSER.

An example illustrating the relationship between the measures determined to constitute the BSER for the source category and the actions that may be undertaken by individual sources that are therefore also part of the BSER is the substitution of zero-emitting generation for CO_2-emitting generation. This measure involves two distinct actions: Increasing the amount of zero-emitting generation and reducing the amount of CO_2-emitting generation. From the perspective of the source category, the two actions are halves of a single balanced endeavor, but from the perspective of any individual affected EGU, the two actions are separable, and a particular affected EGU may decide to implement either or both of the actions. Further, an individual source may choose to invest directly in actions at its own facility or an affiliated facility or to cross-invest in actions at other facilities on the interconnected electricity system.

To reiterate the overall context for the BSER: In this rule, the EPA determined the BSER, and applied it to the category of affected EGUs to determine the performance levels—that is, the CO_2 emission performance rates—for steam generators and for combustion turbines. States must impose standards of performance on their sources that implement the CO_2 emission performance rates, or, as an alternative method of compliance, in total, achieve the equivalent emissions performance level that the CO_2 emission performance rates would achieve if applied directly to each source as the standard or emissions limitation it must meet.[350] Each state has flexibility in how it assigns the emission limitations to its affected EGUs—and in fact, the state can be more stringent than the guidelines require—but one of the state's choices is to convert the CO_2 emission performance rates into standards of performance—which may incorporate emissions trading—for each of its affected EGUs. If a state does so, then the affected EGUs may achieve their emission limits by taking the actions that qualify as the BSER. Since the BSER and, in this case its constituent elements, reflect the criteria of reasonable cost and other BSER criteria, the BSER assures that there is at least one pathway—the CO_2 emission performance rates—for the state and its affected EGUs to take that achieves the requisite level of emission reductions, while, again, assuring that the affected EGUs can achieve those emission limits

[345] *Sierra Club* v. *Costle,* 657 F.2d at 319.

[346] *Sierra Club* v. *Costle,* 657 F.2d at 321; *see also New York* v. *Reilly,* 969 F. 2d at 1150 (because Congress did not assign the specific weight the Administrator should assign to the statutory elements, ''the Administrator is free to exercise [her] discretion'' in promulgating an NSPS).

[347] *Lignite Energy Council* v. *EPA,* 198 F.3d 930, 933 (D.C. Cir. 1999) (paragraphing revised for convenience). *See New York* v. *Reilly,* 969 F.2d 1147, 1150 (D.C. Cir. 1992) (''Because Congress did not assign the specific weight the Administrator should accord each of these factors, the Administrator is free to exercise his discretion in this area.''); *see also NRDC* v. *EPA,* 25 F.3d 1063, 1071 (D.C. Cir. 1994) (EPA did not err in its final balancing because ''neither RCRA nor EPA's regulations purports to assign any particular weight to the factors listed in subsection (a)(3). That being the case, the Administrator was free to emphasize or deemphasize particular factors, constrained only by the requirements of reasoned agency decisionmaking.'').

[348] 40 CFR 60.22(b)(5).

[349] In this rulemaking, our determination that the costs are reasonable means that the costs meet the cost standard in the case law no matter how that standard is articulated, that is, whether the cost standard is articulated through the terms that the case law uses, *e.g.,* ''exorbitant,'' ''excessive,'' etc., or through the term we use for convenience, ''reasonableness''.

[350] The approaches that states may take in their plans are discussed in section VIII.

at reasonable cost and consistent with the other factors for the BSER.

This section describes the EPA's process and basis for determining the BSER for the purpose of determining the CO_2 emission performance rates.[351] The EPA is identifying the BSER as a well-established set of measures that have been used by EGUs for many years to achieve various business and policy purposes, and have been used in recent years for the specific purpose of reducing EGUs' CO_2 emissions, and that are appropriate for carbon pollution (given its global nature and large quantities, and the limited means to control it) and afforded by the highly integrated nature of the utility power sector. We evaluated these measures with a view to the states' obligation to establish standards of performance and included in our BSER determination consideration of the range of options available for states to employ in establishing those standards of performance. These measures include: (i) Improving heat rate at existing coal-fired steam EGUs on average by a specified percentage (building block 1); (ii) substituting increased generation from existing NGCC units for reduced generation at existing steam EGUs in specified amounts (building block 2); and (iii) substituting increased generation from new zero-emitting RE generating capacity for reduced generation at existing fossil fuel-fired EGUs in specified amounts (building block 3). It should be noted that building block 2 incorporates reduced generation from steam EGUs and building block 3 incorporates reduced generation from all fossil fuel-fired EGUs.[352] Further, as discussed below, given the global nature of carbon pollution and the highly integrated utility power sector, each of the building blocks incorporates various mechanisms for facilitating cross-investment by individual affected EGUs in emission rate improvements or emission reduction activities at other locations on the interconnected electricity system. The range of mechanisms includes bilateral investment of various kinds; the issuance and acquisition of ERCs representing the emissions-reducing effects of specific activities, where available under state plans; and more general emissions trading using rate-based credits or mass-based allowances (as discussed in section V.A.2.f. below), where the affected EGUs are operating under standards of performance that incorporate emissions trading.[353]

The set of measures identified as the BSER for the source category encompasses a menu of actions that are part of the BSER and that individual affected EGUs may implement in different amounts and combinations in order to achieve their emission limits at reasonable cost. This menu includes actions that: (i) Affected steam EGUs can implement to improve their heat rates; (ii) affected steam EGUs can implement to increase generation from lower-emitting existing NGCC units in specified amounts; (iii) all affected EGUs can implement to increase generation from new low- or zero-carbon generation sources in specified amounts; (iv) all affected EGUs can implement to reduce their generation in specified amounts; and (v) all affected EGUs operating under a standard of performance that incorporates emissions trading can implement by means of purchasing rate-based emission credits or mass-based emission allowances from other affected EGUs, since the effect of the purchase would be the same as achieving the other listed actions through direct means.[354]

Importantly, affected EGUs also have available numerous other measures that are not included in the BSER but that could materially help the EGUs achieve their emission limits and thereby provide compliance flexibility. Examples include, among numerous other approaches, investment in demand-side EE, co-firing with natural gas (for coal-fired steam EGUs), and investment in new generating units using low- or zero-carbon generating technologies other than those that are part of building block 3.

b. *The EPA's review of measures for determining the BSER.* The EPA described in the proposal for this rule the analytical process by which the EPA determined the BSER for this source category. The EPA is finalizing large parts of that analysis, but the EPA is also refining that analysis as informed by the information and data discussed by commenters and our further evaluation. What follows is the EPA's final determination.

As described in the proposal, to determine the BSER, the EPA began by considering the characteristics of CO_2 pollution and the utility power sector. Not surprisingly, whenever the EPA begins the regulatory process under section 111, it initially undertakes these same inquiries and then proceeds to fashion the rule to fit the industry. For example, in 1979, the EPA finalized new standards of performance to limit emissions of SO_2 from new, modified, and reconstructed EGUs.[355] In assessing the final SO_2 standard, the EPA carried out extensive analyses of a range of alternative SO_2 standards ''to identify environmental, economic, and energy impacts associated with each of the alternatives considered at the national and regional levels.'' [356] In identifying the best system underlying the final standard, the EPA evaluated ''coal cleaning and the relative economics of FGD [flue gas desulfurization] and coal cleaning'' together as the ''best demonstrated system for SO_2 emission reduction.'' [357] The EPA also took into account the unique features of power transmission along the interconnected grid and the unique commercial relationships that rely on those features.[358]

Similarly, in 1996, the EPA finalized section 111(b) standards and 111(d) emission guidelines to ensure that certain municipal solid waste (MSW) landfills controlled landfill gases to the level achievable through application of the BSER.[359] EPA's identification of this BSER was critically influenced by the ''unique emission pattern of

[351] Other sections in this preamble describe how EPA calculated the CO_2 emission performance rates based on the BSER.

[352] The building block measures are not designed to reduce electricity generation overall; they are focused on maintaining the same level of electricity generation, but through less polluting processes.

[353] Conditions for the use of these mechanisms under various state plans are discussed in section VIII.

[354] Again, conditions for the use of these mechanisms under various state plans are discussed in section VIII.

[355] The need for new standards was due in part to findings that in 1976, steam electric generating units were responsible for ''65 percent of the SO_2 . . . emissions on a national basis.'' 44 FR 33580, 33587 (June 11, 1979). The EPA explained that [u]nder the current performance standards for power plants, national SO_2 emissions are projected to increase approximately 17 percent between 1975 and 1995. Impacts will be more dramatic on a regional basis.'' *Id.* Thus, ''[o]n January 27, 1977, EPA announced that it had initiated a study to review the technological, economic, and other factors needed to determine to what extent the SO_2 standard for fossil-fuel-fired steam generators should be revised.'' *Id.* at 33587–33588.

[356] 44 FR 33580, 33582 (June 11, 1979).

[357] 44 FR 33580, 33593. The EPA considered an investigation by the U.S. Department of the Interior regarding the amount of sulfur that could be removed from various coals by physical coal cleaning. *Id.* at 33593.

[358] *See* 44 FR 33580, 33597–33600 (taking into account ''the amount of power that could be purchased from neighboring interconnected utility companies'' and noting that ''[a]lmost all electric utility generating units in the United States are electrically interconnected through power transmission lines and switching stations'' and that ''load can usually be shifted to other electric generating units'').

[359] 61 FR 9905, 9905 (March 12, 1996). In the rule, the EPA referred to the BSER for both new and existing MSW landfills as ''the best demonstrated system of continuous emission reduction,'' as well as the ''BDT''—short for ''best demonstrated technology.'' *See, e.g., id.* at 9905–07, 9913–14.

landfills.'' [360] Unlike ''typical stationary source[s],'' which only generate emissions while in operation, MSW landfills can ''continue to generate and emit a significant quantity of emissions'' long after the facility has closed or otherwise stopped accepting waste.[361] In recognition of this salient and unique characteristic of landfills, the EPA set the BSER based on an emission-reducing system of gas collection and control that remained in place as long as emissions remained above a certain threshold—even after the regulated landfill had permanently closed.[362] The EPA acknowledged that for some landfills, it could take 50 to 100 years for emissions to drop below the cutoff.[363]

For this rule, we discuss at length in the proposed rule and in section II above the unique characteristics of CO_2 pollution. The salient facts include the global nature of CO_2, which makes the specific location of emission reductions unimportant; the enormous quantities of CO_2 emitted by the utility power sector, coupled with the fact that CO_2 is relatively unreactive, which make CO_2 much more difficult to mitigate by measures or technologies that are typically utilized within an existing power plant; the need to make large reductions of CO_2 in order to protect human health and the environment; and the fact that the utility power sector is the single largest source category by a considerable margin.

We also discuss at length in the proposal and in section II above the unique characteristics of the utility power sector. Topics of that discussion include the physical properties of electricity and the integrated nature of the electricity system. Here, we reiterate and emphasize that the utility power sector is unique in the extent to which it must balance supply and demand on a real-time basis, with limited electricity storage capacity to act as a buffer. In turn, the need for real-time synchronization across each interconnection has led to a uniquely high degree of coordination and interdependence in both planning and real-time system operation among the owners and operators of the facilities comprised within each of the three large electrical interconnections covering the contiguous 48 states. Given these unique characteristics, it is not surprising that the North American power system has been characterized as a ''complex machine.'' [364] The core function of providing reliable electricity service is carried out not by individual electricity generating units but by the complex machine as a whole. Important subsidiary functions such as management of costs and management of environmental impacts are also carried out to a great extent on a multi-unit basis rather than an individual-unit basis. Generation from one generating unit can be and routinely is substituted for generation from another generating unit in order to keep the complex machine operating while observing the machine's technical, environmental, and other constraints and managing its costs.

The EPA also reviewed broad trends within the utility power sector.[365] It is evident that, in the recent past, coal-fired electricity generation has been reduced, and projected future trends are for continued reduction. By the same token, lower-emitting NGCC generation and renewable generation have increased, and projected future trends are for continued increases.[366] A survey of integrated resource plans (IRPs), included in the docket, shows that fossil fuel-fired EGUs are taking actions to reduce emissions of both non-GHG air pollutants and GHGs.[367] Some fossil fuel-fired EGUs are investing in lower- or zero-emitting generation. In fact, our review indicates that the great majority of fossil fuel-fired generators surveyed are including new RE resources in their planning. In addition, some fossil fuel-fired EGUs are using those measures to replace their higher-emitting generation. Some fossil fuel-fired generators appear to be reducing their higher-emitting generation without fully replacing it themselves. These measures in aggregate result in the replacement of higher-emitting generation with lower- or zero-emitting generation, reflecting the integrated nature of the electricity system.

The EPA examined state and company programs intended at least in part to reduce CO_2 from fossil fuel-fired power plants. These programs include GHG performance standards established by states including California, New York, Oregon, and Washington; utility planning approaches carried out by companies in Colorado and Minnesota; and renewable portfolio standards (RPS) established in more than 25 states.[368] They also include market-based initiatives, such as RGGI and the GHG emissions trading program established by the California Global Warming Solutions Act, and conservation and demand reduction programs.

We also examined federal legislative and regulatory programs, as well as state programs currently in operation, that address pollutants other than CO_2 emitted by the power sector. These programs include, among others, the CAA Title IV program to reduce SO_2 and NO_X, the MATS program to reduce mercury and air toxic emissions, and the CSAPR program to reduce SO_2 and NO_X.[369] This analysis demonstrated that, among other measures, the application of control technology, fuel-switching, and improvements in the operational efficiency of EGUs all resulted in reductions in a range of pollutants. These programs also demonstrate that replacement of higher-emitting generation with lower-emitting generation—including generation shifts between coal-fired EGUs and natural gas-fired EGUs and generation shifts between fossil fuel-fired EGUs and RE generation—also reduces emissions. Some of these programs also include emissions trading among the power plants.

In this rule, when evaluating the types and amounts of measures that the source category can take to reduce CO_2 emissions, we have appropriately taken into account the global nature of the pollutant and the high degree to which each individual affected EGU is integrated into a ''complex machine'' that makes it possible for generation from one generating unit to be replaced with generation from another generating unit for the purpose of reducing generation from CO_2-emitting generating units. We have also taken into account the trends away from higher-carbon generation toward lower- and zero-carbon generation. These factors strongly support consideration of emission reduction approaches that

[360] 61 FR 9905, 9908; *see* 56 FR 24468, 24478 (May 30, 1991) (explaining at proposal that because landfill-gas emission rates ''gradually increase'' from zero after the landfill opens, and ''gradually decrease'' from peak emissions after closure, the EPA's identification of the BSER for landfills inherently requires a determination of ''when controls systems must be installed and when they may be removed'').

[361] *See* U.S. EPA, *Municipal Solid Waste Landfills, Volume 1: Summary of the Requirements for the New Source Performance Standards and Emission Guidelines for Municipal Solid Waste Landfills,* Docket No. EPA–453R/96–004 at 1–3 (February 1999).

[362] 61 FR 9905, 9907–08.

[363] 61 FR 9905, 9908.

[364] S. Massoud Amin, ''Securing the Electricity Grid,'' The Bridge, Spring 2010, at 13, 14; Phillip F. Schewe, The Grid: A Journey Through the Heart of Our Electrified World 1 (2007).

[365] These trends are discussed in more detail in sections V.D. and V.E. below.

[366] Demand-side energy efficiency measures have also increased, and the projected future trends are for continued increase.

[367] See memorandum entitled ''Review of Electric Utility Integrated Resource Plans'' (May 7, 2015) available in the docket.

[368] *See* 79 FR 34848–34850.

[369] Many of these programs are discussed in section II.

focus on the machine as a whole—that is, the overall source category—by shifting generation from dirtier to cleaner sources in addition to emission reduction approaches that focus on improving the emission rates of individual sources.

The factors just discussed that support consideration of emission reduction measures at the source-category level likewise strongly support consideration of mechanisms such as emissions trading approaches, especially since, as discussed in section VIII, the states will have every opportunity to design their section 111(d) plans to allow the affected EGUs in their respective jurisdictions to employ emissions trading approaches to achieve the standards of performance established in those plans. In short, as discussed in more detail in section V.A.2.f. below, it is entirely feasible for states to establish standards of performance that incorporate emissions trading, and it is reasonable to expect that states will do so. These approaches lower overall costs, add flexibility, and make it easier for individual sources to address pollution control objectives. To the extent that the purchase of an emissions credit or allowance represents the purchase of surplus emission reductions by an emitting source, emissions trading represents, in effect, the investment in pollution control by the purchasing source, notwithstanding that the control activity may be occurring at another source. As noted above, the utility power sector has a long history of using the ''complex machine'' to address objectives and constraints of various kinds. When afforded the opportunity to address environmental objectives on a multi-unit basis, the industry has done so. Congress and the EPA have selected emissions trading approaches when addressing regional pollution from the utility power sector contributing to problems such as acid precipitation and interstate transport of ozone and particulate matter. Similarly, states have selected market-based approaches for their own programs to address regional and global pollutants. The industry has readily adapted to that form of regulation, taking advantage of the flexibility and incorporating those programs into the planning and operation of the ''machine.'' Further reinforcing our conclusion that reliance on trading is appropriate is the extensive interest in using such mechanisms that states and utilities demonstrated through their formal comments and in discussions during the outreach process. The role of emissions trading is discussed further in section V.A.2.f. below.

This entire review has made clear that there are numerous measures that, alone or in various combinations, merit analysis for inclusion in the BSER. The review has also made clear that the unique characteristics of CO_2 pollution and the unique, interconnected and interdependent manner in which affected EGUs and other generating sources operate within the electricity sector make certain types of measures and mechanisms available and appropriate for consideration as the BSER for this rule that would not be appropriate for other pollutants and other industrial sectors. For purposes of this discussion, the measures can be categorized in terms of the essential characteristics of the four building blocks described in the proposal: measures that (i) reduce the CO_2 emission rate at the unit; (ii) substitute generation from existing lower-emitting fossil fuel-fired units for generation from higher-emitting fossil fuel-fired units; (iii) substitute generation from new low- or zero-emitting generating capacity, especially RE, for generation from fossil fuel-fired units; and (iv) increase demand-side EE to avoid generation from fossil fuel-fired units. In the proposal, we described our evaluations of various measures in each of these categories. In this rule, with the benefit of comments, we have refined our evaluation of which specific measures should comprise the first three building blocks, and, for reasons discussed below, we have determined that the fourth building block, demand-side EE, should not be included in the BSER in these guidelines.

The measures are discussed more fully below, but it should be noted here that because of the integrated nature of the utility power sector—in which individual EGUs' operations intrinsically depend on the operations of other generators—coupled with the sector's high degree of planning and reliability safeguards, the measures in the second and third categories (which involve generation shifts to lower- and zero-emitting sources) may occur through several different actions from the perspective of an individual source, all of which are equivalent from the perspective of the source category as a whole. First, a higher-emitting fossil unit may invest in cleaner generation without reducing its own generation, which, in the presence of requirements for the source category as a whole to reduce CO_2 emissions, would result in less demand for, and therefore reductions in generation by, other higher-emitting units. Second, a higher-emitting fossil unit may reduce its generation, which, in the presence of requirements for the source category as a whole to reduce CO_2 emissions, would result in increased demand for, and therefore increased amounts of, cleaner generation. Third, a higher-emitting fossil unit may do both of these things, directly replacing part of its generation with investments in lower- or zero-emitting generation. In addition, for measures in all of the categories, multiple mechanisms exist by which an individual affected EGU may make these investments, ranging from bilateral investments, to purchase of credits representing the emissions-reducing benefits of specific activities, to purchase of general rate-based emissions credits or mass-based emission allowances. As discussed below, mechanisms involving tradable credits or allowances are well within the realm of consideration for the standards of performance states can choose to apply to their EGUs and hence, are entirely appropriate for EPA to consider in evaluating these measures in the course of making its BSER determination.

c. State establishment of standards of performance and source compliance. Before identifying in detail the measures that the BSER comprises, it is useful to describe the process by which the states establish the standards of performance with which the affected EGUs must comply, and the implications for the sources that will be operating subject to those standards of performance. As part of the EPA's emission guidelines in this rule, and based on the BSER, the EPA is identifying CO_2 emission performance rates that reflect the BSER and, pursuant to subsection 111(d)(1), requiring states to establish standards of performance for affected EGUs in order to implement those rates. States, of course, could simply impose those rates on each affected EGU in their respective jurisdictions, but we are also offering states alternative approaches to carrying out their obligations. For purposes of defining these alternatives and facilitating states' efforts to formulate compliance plans encompassing maximum flexibilities, we are aggregating the performance rates into goals for each state. The state, in turn, has the option of setting specific standards of performance for its EGUs such that the emission limitations from the EGUs operating under those standards of performance together meet the performance rates or the state goal. To do this, the state must adopt a plan that establishes the EGUs' standards of performance and that implements and enforces those standards.

Each state has significant flexibility in several respects. For example, as mentioned, a state may impose standards of performance on its steam EGU sources and on its combustion turbine sources that simply reflect the respective CO_2 emission performance rates for those subcategories set in the emission guidelines. Alternatively, a state may impose standards with differing degrees of stringency on various sources, and, in fact, may be more stringent overall than its state goal requires. In addition—and most importantly for purposes of describing the BSER—a state may set standards of performance as mass limits (*e.g.,* tons of CO_2 per year) rather than as emission rates (*e.g.,* lbs of CO_2 per MWh). Moreover, a state may make the limits tradable (subject to conditions described in section VIII below), whether the limits are rate-based or mass-based. The form of the emission limits, whether emission rate limits or mass limits, has implications for what specific actions that are part of the BSER the individual affected EGUs may take to achieve those limits as well as what specific non-BSER measures are available to the individual affected EGUs for compliance flexibility. For example, if an individual source chooses to adopt building block 3 by both investing in lower- or zero-emitting generation and reducing its own generation, both those actions will be accounted for in its emission rate and both will therefore help the source meet its rate-based limit. If the same individual source takes the same actions but is subject to a mass-based limit, the action of reducing its generation will directly count in helping the source meet its own mass-based limit but the action of investing in cleaner generation will not. However, the investment in lower-or zero-emitting generation by that source and other sources collectively will help the overall source category achieve the emission limits consistent with the BSER and in doing so will make it easier for that source and other sources collectively to meet their mass-based limits.

In instances where a state establishes standards of performance that incorporate emissions trading, the tradable credits or allowances can serve as a medium through which affected EGUs can invest in any emission reduction measure.

d. *Identification of the BSER measures.* We now discuss the evaluation of potential measures for inclusion in the BSER for the source category as a whole.

(1) *Measures that reduce individual affected EGUs' CO_2 emission rates.*

As described in the proposal, the measures that the affected EGUs could implement to improve their CO_2 emission rates include a set of measures that the EPA determined would result in improvements in heat rate at coal-fired steam EGUs in the amount of 6 percent on average, and the EPA proposed that this set of measures qualifies as a component of the BSER. In this final rule, the EPA concludes that those measures do qualify as a component of the BSER. However, as described in section V.C. below, based on responsive comments and further evaluation, the EPA has refined its approach to quantifying the emission reductions achievable through heat rate improvements and no longer includes a separate increment of emission reductions attributable to equipment upgrades. Also, rather than evaluating the emission reductions available from these measures on a nationwide basis as in the proposal, the EPA has quantified the emission reductions achievable through building block 1 on a regional basis, consistent with the EPA's proposals to better reflect the regional nature of the interconnected electrical system and the treatment of the other building blocks in this final rule. As a result of these refinements, the EPA is identifying the heat rate improvements achievable by coal-fired steam EGUs as 4.3 percent for the Eastern Interconnection, 2.1 percent for the Western Interconnection, and 2.3 percent for the Texas Interconnection. The refinements are based, in significant part, on the numerous comments we received on our proposed approaches, especially those from states and utilities.

These heat rate improvement measures include best practices such as improved staff training, boiler chemical cleaning, cleaning air preheater coils, and use of various kinds of software, as well as equipment upgrades such as turbine overhauls. These are measures that the owner/operator of an affected coal-fired steam EGU may take that would have the effect of reducing the amount of CO_2 the source emits per MWh. As a result, these measures would help the source achieve an emission limit expressed as either an emission rate limit or as a mass limit. We note again that in the context both of the integrated electricity system and of available and anticipated state approaches to setting standards of performance, emissions trading approaches could be used as mechanisms through which one affected EGU could invest in heat rate improvements at another EGU. We note this aspect below in describing the actions an individual affected EGU can take to implement the BSER and discuss it in more detail in section V.A.2.f.

These heat rate improvements are a low-cost option that fit the criteria for the BSER, except that they lead to only small emission reductions for the source category.[370] Given the magnitude of the environmental problem and projections by climate scientists that much larger emission reductions are needed from fossil fuel-fired EGUs to address climate change, the EPA looked at additional measures to reduce emission rates. This reflects our conclusion that, given the availability of other measures capable of much greater emission reductions, the emission reductions limited to this set of heat rate improvement measures would not meet one of the considerations critical to the BSER determination—the quantity of emissions reductions resulting from the application of these measures is too small for these measures to be the BSER by themselves for this source category.

Specifically, as described in the proposal, the EPA also considered co-firing (including 100 percent conversion) with natural gas, a measure that presented itself in part because of the recent increase in availability and reduction in price of natural gas, and the industry's consequent increase in reliance on natural gas.[371] The EPA also considered implementation of carbon capture and storage (CCS).[372] The EPA found that some of these co-firing and CCS measures are technically feasible and within price ranges that the EPA has found to be cost effective in the context of other GHG rules, that a segment of the source category may implement these measures, and that the resulting emission reductions could be potentially significant.

However, these co-firing and CCS measures are more expensive than other available measures for existing sources. This is because the integrated nature of the electricity system affords significantly lower cost options, ones that fossil fuel-fired power plants

[370] As further discussed below, if heat rate improvements at coal-fired steam EGUs were implemented in isolation, without other measures to reduce CO_2 emissions, the heat rate improvements could lead to increases in competitiveness and utilization of the coal-fired EGUs—a so-called ''rebound effect''—causing increases in CO_2 emissions that could partially or even entirely offset the CO_2 emission reductions achieved through the reductions in the amount of CO_2 emissions per MWh of generation.

[371] The EPA further addressed co-firing in the October 30, 2014 NODA. 79 FR 64549–51.

[372] CCS is also sometimes referred to as carbon capture and sequestration.

throughout the U.S. and in foreign nations are already using to reduce their CO_2 emissions.

The less expensive options include shifting generation to existing NGCC units—an option that has become particularly attractive in light of the increased availability and lower prices of natural gas—as well as shifting generation to new RE generating units. A comparison of the costs of converting an existing coal-fired boiler to burn 100 percent natural gas compared to the cost of shifting generation to an existing NGCC unit illustrates this point. Because an NGCC unit burns natural gas significantly more efficiently than an affected steam EGU does, the cost of shifting generation from the steam EGU to an existing NGCC unit is significantly cheaper in most cases than more aggressive emission rate reduction measures at the steam EGU. As a result, as a practical matter, were the EPA to include co-firing and CCS in the BSER and promulgate performance standards accordingly, few EGUs would likely comply with their emission standards through co-firing and CCS; rather, the EGUs would rely on the lower cost options of substituting lower- or zero-emitting generation or, as a related matter, reducing generation.[373]

The EPA also considered heat rate improvement opportunities at oil- and gas-fired steam EGUs and NGCC units and found that the available emission reductions would likely be more expensive or too small to merit consideration as a material component of the BSER.

Thus, in reviewing the entire range of control options, it became clear that controlling CO_2 from affected EGUs at levels that are commensurate with the sector's contribution to GHG emissions and thus necessary to mitigate the dangers presented by climate change, could depend in part, but not primarily, on measures that improve efficiency at the power plants. Rather, most of the CO_2 controls need to come in the form of those other measures that are available to the utility power sector thanks specifically to the integrated nature of the electricity system, and that involve, in one form or another, replacement of higher emitting generation with lower- or zero-emitting generation.

Although the presence of lower-cost options that achieve the emission reduction goals means that the EPA is not identifying either natural gas co-firing or CCS at coal-fired steam EGUs, or heat rate improvements at other types of EGUs, as part of the BSER, those controls remain measures that some affected EGUs may be expected to implement and that as a result, will provide reductions that those affected EGUs may rely on to achieve their emission limits or may sell, through emissions trading, to other affected EGUs to achieve emission limits (to the extent permitted under the relevant section 111(d) plans). Another example of a non-BSER measure that an affected EGU in certain circumstances could choose to implement is the conversion of waste heat from electricity generation into useful thermal energy. The EPA further discusses the potential use of these non-BSER measures for compliance flexibility below.

The EPA's quantification of the CO_2 emission reductions achievable through heat rate improvements as a component of the BSER (building block 1) is discussed in section V.C. of this preamble and in the GHG Mitigation Measures TSD for the CPP Final Rule.

(2) *Measures available because of the integrated electricity system.*

To determine the BSER that meets the expectations and requirements of the CAA, including the achievement of meaningful reductions of CO_2, the EPA turned next to the set of measures that presented themselves as a result of the fact that the operations of individual affected EGUs are interdependent on and integrated with one another and with the overall electricity system. Those are the measures in the categories represented in the proposal by building blocks 2, 3, and 4. This section discusses the components of the BSER that relate to building blocks 2 and 3, which the EPA is finalizing as components of the BSER. This section also discusses the measures comprising the proposed building block 4, which the EPA is not including in the BSER in this final rule.

It bears reiterating that the extent to which the operations of individual affected EGUs are integrated with one another and with the overall electricity system is a highly salient and unique attribute of this source category. Because of this integration, the individual sources in the source category operate through a network that physically connects them to each other and to their customers, an interconnectedness that is essential to their operation under the status quo and by all indications is projected to be augmented further on a continual basis in the future to address fundamental objectives of reliability assurance and cost reduction. This physical interconnectedness exists to serve a set of interlocking regimes that, to a substantial extent, determine, if not dictate, any given EGU's operations on a nearly moment-to-moment basis. In analyzing BSER from the perspective of the overall source category, because the affected EGUs are connected to each other operationally, a combination of dispatching and investment in lower- and zero-emitting generation allows the replacement of higher-emitting generation with lower-emitting and zero-emitting generation (measures in building blocks 2 and 3), and thereby reduces emissions while continuing to serve load.

As noted above, substitution of higher-emitting generation for lower- or zero-emitting generation may include reduced generation, depending on the specific action taken by the individual EGU. Likewise, when incorporated into standards of performance, emissions trading mechanisms may be readily used for implementing these building blocks. We discuss these aspects below in describing the actions that individual sources may take to implement the building blocks.

(a) *Substituting generation from lower-emitting affected EGUs for generation from higher-emitting affected EGUs.*

In the proposal, the EPA observed that substantial CO_2 emission reductions could be achieved at reasonable cost by increasing generation from existing NGCC units and commensurately reducing generation from steam EGUs. Because NGCC units produce much less CO_2 per MWh of generation than steam EGUs—typically less than half as much CO_2 as coal-fired steam EGUs, which account for most generation from steam EGUs—this generation shift reduces CO_2 emissions. We also noted that because NGCC units can generate as much as 46 percent more electricity from a given quantity of natural gas than a steam unit can, generation shifting from coal-fired steam EGUs to existing NGCC units is a more cost-effective strategy for reducing CO_2 emissions from the source category than converting coal-fired steam EGUs to combust natural gas or co-firing coal and natural gas in steam EGUs. We proposed to find that shifting generation consistent with a 70 percent target utilization rate (based on nameplate capacity) for NGCC units was feasible and should be a component of the BSER.

As described in section V.D. below, analysis reflecting consideration of the many comments we received on the EPA's proposal with respect to this issue supports the inclusion of generation shifting from higher-emitting to lower-emitting EGUs as a component of the BSER. Shifting of generation

[373] Many EGUs would also rely on demand-side energy efficiency measures.

among EGUs is an everyday occurrence within the integrated operations of the utility power sector that is used to ensure that electricity is provided to meet customer demands in the most economic manner consistent with system constraints. Generation shifting to lower-emitting units has been recognized as an approach for reducing emissions in other EPA rules such as CSAPR.

The EPA's analysis continues to show that the magnitude of emission reductions included in the proposed rule from generation shifting is achievable. In response to our request for comment on the proposed target utilization rates, some commenters stated that summer capacity ratings are a more appropriate basis upon which to compute a target utilization than nameplate capacity ratings used at proposal. We agree, and accordingly, using the same data on historical generation as at proposal, we have reanalyzed feasible NGCC utilization levels expressed in terms of summer capacity ratings and have found that a 75 target utilization rate based on summer capacity ratings is feasible.

The EPA is finalizing a determination that generation shift from higher-emitting affected EGUs to lower-emitting affected EGUs is a component of the BSER (building block 2). Our quantification of the associated emission reductions is discussed in section V.D. of this preamble and in the GHG Mitigation Measures TSD for the CPP Final Rule.

(b) *Substituting increased generation from new low- or zero-carbon generating capacity for generation from affected EGUs.*

Reducing generation from fossil fuel-fired EGUs and replacing it with generation from lower- or zero-emitting EGUs is another method for reducing CO_2 emissions from the utility power sector. In the proposal, the EPA identified RE generating capacity and nuclear generating capacity as potential sources of lower- or zero-CO_2 generation that could replace higher-CO_2 generation from affected EGUs.

(i) *Increased generation from new RE generating capacity.*

The EPA's survey of trends and actions already being taken in the utility power sector indicated that RE generating capacity and generation have grown rapidly in recent years, in part because of the environmental benefits of shifting away from fossil fuel-fired generation and in part because of improved economics of RE generation relative to fossil fuel-fired generation. It is clear that increasing the amount of new RE generating capacity and allowing the increased RE generation to replace generation from fossil fuel-fired EGUs can reduce CO_2 emissions from the affected source category. Accordingly, we proposed to include replacement of defined quantities of fossil generation by RE generation in the BSER.

The EPA is finalizing the determination that substitution of RE generation from new RE generating capacity is a component of the BSER but, with the benefit of comments responding to the EPA's proposals on regionalization and techno-economic analytic approaches, the EPA has adjusted the approach for determining the quantities of RE generation. As part of the adjustment in approach, we have also refocused the quantification solely on generation from new RE generating capacity rather than total (new and existing) RE generating capacity as in the proposal. Our quantification of the RE generation component of the BSER is discussed in section V.E. of the preamble and in the GHG Mitigation Measures TSD for the CPP Final Rule.

(ii) *Increased and preserved generation from nuclear generating capacity.*

In the June 2014 proposal, the EPA also identified the replacement of generation from fossil fuel-fired EGUs with generation from nuclear units as a potential approach for reducing CO_2 emissions from the affected source category. We proposed to include two elements of nuclear generation in the BSER: An element representing projected generation from nuclear units under construction; and an element representing preserved generation from existing nuclear generating capacity at risk of retirement, and we took comment on all aspects of these proposals.

Like generation from new RE generating capacity, generation from new nuclear generating capacity can clearly replace fossil fuel-fired generation and thereby reduce CO_2 emissions. However, there are also important differences between these types of low- or zero-CO_2 generation. Investments in new nuclear capacity are very large capital-intensive investments that require substantial lead times. By comparison, investments in new RE generating capacity are individually smaller and require shorter lead times. Also, important recent trends evidenced in RE development, such as rapidly growing investment and rapidly decreasing costs, are not as clearly evidenced in nuclear generation. We view these factors as distinguishing the under-construction nuclear units from RE generating capacity, indicating that the new nuclear capacity is likely of higher cost and therefore less appropriate for inclusion in the BSER. Accordingly, as described in section V.A.3., the EPA is not finalizing increased generation from under-construction nuclear capacity as a component of the BSER.

The EPA is likewise not finalizing the proposal to include a component representing preserved existing nuclear generation in the BSER. On further consideration, we believe it is inappropriate to base the BSER on elements that will not reduce CO_2 emissions from affected EGUs below current levels. Existing nuclear generation helps make existing CO_2 emissions lower than they would otherwise be, but will not further lower CO_2 emissions below current levels. Accordingly, as described in section V.A.3., the EPA is not finalizing preservation of generation from existing nuclear capacity as a component of the BSER.

(iii) *Generation from new NGCC units.*

New NGCC units—that is, units that had not commenced construction as of January 8, 2014, the date of publication of the proposed CO_2 standards of performance for new EGUs under section 111(b)—are not subject to the standards of performance that will be established for existing sources under section 111(d) plans based on the BSER determined in this final rule. In the June 2014 proposed emission guidelines for existing EGUs, the EPA solicited comment on whether to include this measure in the BSER. Commenters raised numerous concerns, and after consideration of the comments, we are not including replacement of generation from affected EGUs through the construction of new NGCC capacity in the BSER. In this section, we discuss the reasons for our approach.

The EPA did not include reduced generation from affected EGUs achieved through construction and operation of new NGCC capacity in the proposed BSER because we expected that the CO_2 emission reductions achieved through such actions would, on average, be more costly than CO_2 emission reductions achieved through the proposed BSER measures. However, our determination not to include new construction and operation of new NGCC capacity in the BSER in this final rule rests primarily on the achievable magnitude of emission reductions rather than costs.

Unlike emission reductions achieved through the use of any of the building blocks, emission reductions achieved through the use of new NGCC capacity require the construction of additional CO_2-emitting generating capacity, a consequence that is inconsistent with the long-term need to continue reducing CO_2 emissions beyond the reductions that will be achieved through this rule. New generating assets are planned and built for long lifetimes—frequently 40 years or more—that are likely longer than the expected remaining lifetimes of the steam EGUs whose CO_2 emissions would initially be displaced be the generation from the new NGCC units. The new capacity is likely to continue to emit CO_2 throughout these longer lifetimes, absent decisions to retire the units before the end of their planned lifetimes or to install CCS technology in the future at substantial additional cost. Because of the likelihood of CO_2 emissions for decades, the overall net emission reductions achievable through the construction and operation of new NGCC are less than for the measures including in the BSER, such as increased generation at existing NGCC capacity, which would be expected to reach the end of its useful life sooner than new NGCC capacity, or construction and operation of zero-emitting RE generating capacity. We view the production of long-term CO_2 emissions that otherwise would not be created as inconsistent with the BSER requirement that we consider the magnitude of emissions reductions that can be achieved. For this reason, we are not including replacement of generation from affected EGUs through the construction and operation of new NGCC capacity in the final BSER.

Commenters also raised a concern with the interrelation of section 111(b) and section 111(d). New NGCC capacity is distinguished from the other non-BSER measures discussed above by the fact that its CO_2 emissions would be subject to the CO_2 standards for new EGUs being established under section 111(b). Section 111 creates an express distinction between the sources subject to section 111(b) and the sources subject to section 111(d), and commenters expressed concern that to allow section 111(b) sources to play a direct role in setting the BSER under section 111(d) would be inconsistent with congressional intent to treat the two sets of sources separately. Section VIII of this preamble includes a discussion of ways to address new NGCC capacity in the context of different types of section 111(d) plans.

(c) *Increasing demand-side EE to avoid generation and emissions from fossil fuel-fired EGUs.*

The final category of approaches for reducing generation and CO_2 emissions from affected EGUs that the EPA considered in the proposal involves increasing demand-side EE. When demand-side EE is increased, energy consumers need less electricity in order to provide the same level of electricity-dependent services—*e.g.,* heating, cooling, lighting, and use of motors and electronic devices. Through the integrated electricity system, including the connection of customers to affected EGUs through the electricity grid, reduced demand for electricity, in turn, leads to reduced generation and reduced CO_2 emissions. Our examination of actions and trends underway in the utility power sector confirmed that investments in demand-side EE programs are increasing. We proposed to include avoidance of defined quantities of fossil fuel-fired generation through increased demand-side EE as a component of the BSER (proposed building block 4). However, we also took comment on which building blocks should comprise the BSER and on our determination as to whether each building block met the various statutory factors.

Commenters expressed a wide range of views on the proposed reliance on demand-side EE in the BSER. Some commenters strongly supported the proposal, with suggestions for improvements, while some commenters strongly opposed the proposal and took the position that it exceeded the EPA's legal authority. We do not address the merits of these comments here because, for the reasons discussed in section V.B.3.c.(8) below, we are not finalizing the proposal to include avoided generation achieved through demand-side EE as a component of the BSER. However, we note that most commenters also supported the use of demand-side EE for compliance whether or not it is used in determining the BSER, and we are allowing demand-side EE to be used for that purpose. (We also emphasize that the emission limitations reflective of the BSER are achievable even if aggregate generation is not reduced through demand-side EE.)

(3) *Further analysis to quantify the BSER.*

While the discussion above summarizes how and why the components of the BSER were determined in terms of qualitative characteristics, it still leaves a wide range of potential stringencies for the BSER. As explained in sections V.C., V.D., and V.E. below, discussing building blocks 1, 2, and 3 respectively, the EPA has determined a reasonable level of stringency for each of the building blocks rather than the maximum possible level of stringency. We have taken this approach in part to ensure that there is ''headroom'' within the BSER measures that provides greater assurance of the achievability of the BSER for the source category and for individual sources. We believe this approach is permissible under the CAA. Another aspect of our methodology for computing the CO_2 emission performance rates, further described in section V.A.3.f. and section VI, is that the CO_2 emission performance rate applicable to a given source subcategory in all three interconnections reflects the emission rate achievable by that source subcategory through application of the building blocks in the interconnection where that achievable emission rate is the highest (*i.e.,* least stringent).[374] This aspect of our methodology not only ensures that the nationwide CO_2 emission performance rates are achievable by affected EGUs in all three interconnections but also provides additional headroom within the BSER for affected EGUs in the two interconnections that did not set the CO_2 emission performance rates ultimately used. Additional headroom within the BSER is available through the use of emissions trading approaches, because the final rule does not limit the use of these mechanisms to sources within the same interconnections. In fact, in response to proposals that emerged from the comment record and direct engagement with states and stakeholders reflecting their strong interest in pursuing multi-state approaches, the guidelines include mechanisms for implementing standards of performance that incorporate interstate trading, as discussed in section VIII. (In addition, as further discussed below, the rule also permits section 111(d) plans to allow the use of non-BSER measures for compliance in certain circumstances, increasing both compliance flexibility and the assurance that the emission limitations reflecting application of the BSER are achievable.)

Further, the sets of measures in each of these individual building blocks, in the stringency assigned in this rule, meet the criteria for the BSER. That is, they each achieve the appropriate level of reductions, are of reasonable cost, do not impose energy penalties on the

[374] Specifically, the annual CO_2 emission performance rates applicable to steam EGUs in all three interconnections are the annual emission rates achievable by that subcategory in the Eastern Interconnection through application of the building blocks. Similarly, the annual CO_2 emission performance rates applicable to stationary combustion turbines in all three interconnections are the annual emission rates achievable by that subcategory in the Texas Interconnection for years from 2022 to 2026, and in the Eastern Interconnection for years from 2027 to 2030, through application of the building blocks. Additional information is provided in the CO_2 Emission Performance Rate and State Goal Computation TSD in the docket.

affected EGUs and do not result in non-air quality pollutants, and have acceptable cost and energy implications on a source-by-source basis and for the energy sector as a whole. In addition, as explained below, each is adequately demonstrated. Importantly, past industry practice and current trends strongly support each of the building blocks, as do federal and state pollution control programs that require or result in similar measures.

For example, all of the measures in building blocks 2 and 3 have been implemented for decades, initially for reasons unrelated to pollution control, then in recent years in order to control non-GHG air pollutants, and more recently, for purposes of CO_2-emission control by states and companies. Moreover, Congress itself recognized in enacting the acid rain provisions of CAA Title IV that RE measures reduce CO_2 from affected EGUs. In addition, the EPA has relied on the measures in building blocks 2 and 3 in other rules.

It should also be noted that building blocks 2 and 3 also meet the criteria for the BSER in combination with one another and with building block 1, as described below.

e. *Actions that individual affected EGUs could take to apply or implement the building blocks.* We now turn to a summary of measures or actions that individual EGUs could take to apply or implement the building blocks and that are therefore, in that sense, part of the BSER.

(1) *Improvement in CO_2 emission rate at the unit.*

An affected EGU may take steps to improve its CO_2 emission rate as discussed above for the source category as a whole. As discussed in section V.C., the record makes clear that coal-fired steam EGUs can make, and have made, heat rate improvements to a greater or lesser degree, resulting in reductions in CO_2 emissions. The resulting improvement in an EGU's CO_2 emission rate would help the EGU achieve an emission limit imposed in the form of an emission rate. If the EGU's emission limit is imposed in the form of a mass standard, the heat rate improvement would also lower the EGU's mass emissions provided that the EGU held the amount of its generation constant or increased its generation by a smaller percentage than the efficiency improvement. Under a mass-based standard that incorporates emission trading, an EGU that improves its heat rate would need fewer emission allowances for each MWh of generation whatever level of generation it chose to produce.

(2) *Actions to implement measures in building blocks 2 and 3.*

Viewing the BSER from the perspective of an individual EGU, there are several ways that affected EGUs can access the measures in building blocks 2 and 3, thanks to the integrated nature of the electricity system, coupled with the system's high degree of planning and reliability mechanisms. The affected EGUs can: (a) Invest in lower- or zero-emitting generation, which will lead to reductions in higher-emitting generation at other units in the integrated system; (b) reduce their generation, which in the presence of emission reduction requirements applicable to the source category as a whole will have the effect of increasing demand for, and thereby incentivize investment in, the measures in the building blocks elsewhere in the integrated system; or (c) both invest in the measures in the building blocks and reduce their own generation, effectively replacing their generation with cleaner generation. The availability of these options is further enhanced where the individual EGU is operating under a standard of performance that incorporates emissions trading.

(a) *Investment in measures in building blocks 2 and 3.*

An affected EGU may take the following actions to invest in the measures in building blocks 2 and 3. For building block 2, the owner/operator of a steam EGU may increase generation at an existing NGCC unit it already owns, or one that it purchases or invests in. In addition, the owner/operator may, through a bilateral transaction with an existing NGCC unit, pay the unit to increase generation, and acquire the CO_2-reducing effects of that increased generation in the form of a credit, as discussed below.

Similarly, for building block 3, an owner/operator of an affected EGU may build, or purchase an ownership interest in, new RE generating capacity and acquire the CO_2-reducing effects of that increased generation. Alternatively, an owner/operator may, through bilateral transactions, purchase the CO_2-reducing effects of that increased generation from renewable generation providers, again, in the form of a credit.

In case of an investment in either building block 2 or building block 3 by a unit subject to a rate-based form of CO_2 performance standard, it would be reasonable for state plans to authorize affected EGUs to use an approved and validated instrument such as an ''emission rate credit'' (ERC) representing the emissions-reducing benefit of the investment.[375]

When combined with reduced generation, either at the affected EGU or elsewhere in the interconnected system, the types of actions listed above would be fully equivalent to building blocks 2 and 3 when viewed from the perspective of the overall source category. Thus, a source could achieve a standard of performance identical to the applicable CO_2 emission performance rate in the EPA emission guidelines, through implementation of the actions described above for building blocks 2 and 3, along with the actions described further above for building block 1.

The EPA anticipates that in instances where section 111(d) plans provide for the use of instruments such as ERCs as a mechanism to facilitate use of these measures, organized markets will develop so that owner/operators of affected EGUs that have invested in measures eligible for the issuance of ERCs will be able to sell those credits and other affected EGUs will be able to purchase them. Such markets have developed for other instruments used for emissions trading purposes. For example, liquid markets for SO_2 allowances developed rapidly following the implementation of Title IV of the 1990 Clean Air Act Amendments establishing the Acid Rain Program. Members of Congress and industry had expressed concern during the legislative debate that the lack of a liquid SO_2 allowance market would create challenges for affected sources that needed to acquire allowances to meet their compliance obligations. Congress added statutory provisions to ensure that, should a market not develop, sources could purchase needed allowances directly from the EPA. In fact, these provisions went unused because a liquid market for allowances did develop very quickly. Sources engaged in allowance transactions directly with other sources as they sought to lower compliance costs. Market intermediaries offered services to sources to match allowance buyers and sellers and helped sources understand their compliance options. Trade associations worked with members to develop standardized contracts and other tools to facilitate allowance transactions, thereby reducing transaction costs. Similar developments have occurred in state-

[375] Criteria for issuance of valid ERCs and for tracking credits after issuance are discussed in section VIII below.

level renewable portfolio standard programs.[376]

If states choose to allow through their section 111(d) plans mechanisms or standards of performance involving instruments such as ERCs, the EPA believes that there would be an ample supply of such credits, for several reasons. First, as discussed in sections V.D. and V.E., the EPA has established the stringencies for building blocks 2 and 3 at levels that are reasonable and not at the maximum achievable levels, providing headroom for investment in the measures in these building blocks beyond the amounts reflected in the CO_2 emission performance rates reflecting application of the BSER. In addition, if emission limits are set at the CO_2 emission performance rates, affected EGUs in two of the three interconnections on average do not need to implement the building blocks to their full available extent in order to achieve their emission limits (because the performance rates for each source category are the emission rates achievable by that source subcategory through application of the building blocks in the interconnection where that achievable emission rate is the highest), providing further opportunities in those interconnections to generate surplus emission reductions that could be used as the basis for issuance of ERCs. Further, to the extent that section 111(d) plans take advantage of the latitude the final guidelines provide for states to set standards of performance incorporating emissions trading on an interstate basis among affected EGUs in different interconnections, all sources can take advantage of the headroom available in other interconnections. As a result, significant amounts of existing NGCC capacity and potential for RE remain available to serve as the basis for issuance of ERCs for all affected EGUs in both source subcategories to rely on to achieve their emission limits. Because we recognize the ready availability to states of standards of performance that incorporate emissions trading—and because such standards can easily encompass interstate trading—this rule includes by express design a variety of options that states and utilities can select to pursue interstate compliance regimes that mirror the interconnected operation of the electricity system. As a result, the EPA believes that it is reasonable to anticipate that a virtually nationwide emissions trading market for compliance will emerge, and that ERCs will be effectively available to any affected EGU wherever located, as long as its state plan authorizes emissions trading among affected EGUs.[377]

It should also be noted that although in a state that sets emission limits in a rate-based form the measures in building blocks 2 and 3 can be taken into account directly in computations to determine whether an individual affected EGU has achieved its emission limit, in a state that sets emission limits in a mass-based form these measures are not taken into account directly in computations to determine whether an individual affected EGU has achieved its emission limit. However, by reducing generation and therefore CO_2 emissions from the group of affected EGUs within a region, in a state with mass-based limits implementation of these measures facilitates the ability of the individual EGUs within the region to achieve their limits by choosing to reduce their own generation and emissions.

(b) *Reduced generation.*

In addition, the owner/operator of an affected EGU may help itself meet its emission limit by reducing its generation. If the owner/operator reduces generation and therefore the amount of its CO_2 emissions, then, if the affected EGU is subject to an emission rate limit, the owner/operator will need to implement fewer of the building block measures, *e.g.,* buy fewer ERCs, to achieve its emission rate; and if the affected EGU is subject to a mass emission limit, the owner/operator will need fewer mass allowances. As discussed below, at the levels that the EPA has selected for the BSER, reduced generation at higher-emitting EGUs does not decrease the amount of electricity available to the system and end users because lower-emitting (or zero-emitting) generation will be available from other sources.

An owner/operator may take actions to ensure that it reduces its generation. For example, it may accept a permit restriction on the amount of hours that it generates. In addition or alternatively, it may represent the cost of additional emission credits or allowances that would be required due to incremental generation as an additional variable cost that increases the total variable cost considered when dispatch decisions are made for the unit.

Because of the integrated nature of the electricity system, combined with the system's high degree of planning and reliability safeguards, as well as the long planning horizon afforded by this rule, individual affected EGUs can implement the building blocks by reducing generation to achieve their emission performance standards.[378] Individual affected steam EGUs can reduce their generation in the amounts of building blocks 2 and 3, while individual affected NGCC units can reduce their generation in the amount of building block 3. With emission limits for the source category as a whole in place, the resulting reduction in supply of higher-emitting generation will incentivize additional utilization of existing NGCC capacity, the resulting reduction in overall fossil fuel-fired

[376] The emergence of markets under the Acid Rain Program and other environmental programs where trading has been permitted, as well as state and industry support for the development of markets under states' section 111(d) plans, is discussed in a recent report by the Advanced Energy Economy Institute. AEE Institute, *Markets Drive Innovation—Why History Shows that the Clean Power Plan Will Stimulate a Robust Industry Response* (July 2015), available at *https://www.aee.net/aeei/initiatives/epa-111d.html#epa-reports-and-white-papers.*

[377] There is a theoretical possibility—which we view as extremely unlikely—that the affected EGUs in a given state or group of states that has chosen to pursue a technology-specific rate-based approach could have insufficient access to ERCs because of the choices of certain other states to pursue mass-based or blended-rate approaches. We view this as very unlikely in part because of the conservative assumptions used in calculating the emission reductions available through the building blocks and the broad availability of non-BSER emission reduction opportunities, such as energy efficiency, that will generate ERCs. If such a situation arises, and the state or states implementing the technology-specific rates does not have, within the state or states, sufficient ERC-generation potential to match their compliance requirements, the EPA will work with the state or states to ensure that there is a mechanism that the state or states can include in their state plans to allow the affected EGUs in the state or states to generate additional ERCs where the state or states can demonstrate that the ERCs do not represent double-counting under other state programs. One potential mechanism would be to assume for purposes of demonstrating compliance with their standards of performance that the generation replacing any reductions in generation at those affected EGUs that was not paired with verified ERCs came from existing NGCC units in other states from which ERCs were not accessible. In other words, any reductions in fossil steam generation from 2012 levels in a state or states that was implementing technology-specific rates that could not be matched by increases in NGCC generation or by ERCs from zero-emitting sources, and for which it could be demonstrated that no further ERCs can be procured, could generate building block 2 ERCs as if that level of displaced generation were NGCC generation. A demonstration that no further ERCs are procurable would have to include demonstrations that the capacity factor of all NGCC generation in the state or states was expected to be greater than 75 percent and that further deployment of RE would go beyond the amounts found available in the BSER. States could distribute these additional ERCs to ensure compliance by affected EGUs. Before such ERCs could be created by a state or states, a framework would have to be submitted to the EPA for approval including documentation of the levels of fossil steam and NGCC generation in the state or states, a demonstration that no further ERCs are accessible, and the total amount of building block 2 ERCs to be created.

[378] For purposes of this discussion, we assume that coal-fired steam generators also implement building block 1 measures so that they will implement the full set of measures needed to achieve their emission limit.

generation will incentivize investment in additional RE generating capacity, and the integrated system's response to these incentives will ensure that there will be sufficient electricity generated to continue to meet the demand for electricity services.

(c) *Emissions trading.*

As described above, viewed from the perspective of the source category as a whole, it is reasonable for our analysis of the BSER to include an element of source-category-wide multi-unit compliance which could be implemented via a state-set standard of performance incorporating emissions trading, under which EGUs could engage in trading of rate-based emission credits or mass-based emission allowances. By the same token, viewed from the perspective of an individual EGU, consideration of the ready availability to states of the opportunity to establish standards of performance that incorporate emissions trading is integral to our analysis. Accordingly, our assessment of the actions available to individual EGUs for achieving standards of performance reflecting the BSER includes the purchase of rate-based emission credits or mass-based emission allowances, because one of the things an affected EGU can do to achieve its emission limit is to buy a credit or an allowance from another affected EGU that has over-complied. The use of purchased credits or allowances would have to be authorized, of course, in the purchasing EGUs' states' section 111(d) plans and would have to meet conditions set out for such approaches in section VIII below. The role of emissions trading in the BSER analysis is discussed further in section V.A.2.f. below.

f. *The role of emissions trading.* In making its BSER determination here, the EPA examined a number of technologies and emission reduction measures that result in lower levels of CO_2 emissions and evaluated each one on the basis of the several criteria on which the EPA relies in determining the BSER. In contrast to section 111(b), however, section 111(d)(1) obliges the states, not the EPA, to set standards of performance for the affected EGUs in order to implement the BSER. Accordingly, with respect to each measure or control strategy under consideration, the EPA also evaluated whether or not the states could establish standards of performance for affected EGUs that would allow those sources to adopt the measure in question. In this case, the EPA identified a host of factors that persuaded us that states could— and, in fact, may be expected to—establish standards of performance that incorporate emissions trading.[379] These wide-ranging factors include (i) the global nature of the air pollutant in question—*i.e.,* CO_2; (ii) the transactional nature of the industry; (iii) the interconnected functioning of the industry and the coordination of generation resources at the level of the regional grid; (iv) the extensive experience that states—and EGUs—already have with emissions trading; and (v) material in the record demonstrating strong interest on the part of many states and affected EGUs in using emissions trading to help meet their obligations.[380]

The states' and EGUs' interest in emissions trading is rooted in the well-recognized benefits that trading provides. The experience of multiple trading programs over many years has shown that some units can achieve emission reductions at lower cost than others, and a system that allows for those lower-cost reductions to be maximized is more cost-effective overall to the industry and to society. Trading provides an affected EGU other options besides direct implementation of emission reduction measures in its own facility or an affiliated facility when lower-cost emission reduction opportunities exist elsewhere. Specifically, the affected EGU can cross-invest, that is, invest in actions at facilities owned by others, in exchange for rate-based emission credits or mass-based emission allowances. Through cross-investment, trading allows each affected EGU to access the control measures that other affected EGUs decide to implement, which in this case include all the building blocks as well as other measures.

Accordingly, our analysis of the measures under consideration in our BSER determination reflected the well-

[379] As an alternative to authorizing trading that would still provide a degree of multi-unit flexibility, a state could choose in its state plan to give an owner of multiple affected EGUs flexibility regarding how the owner distributes any credits or allowances it acquires among its affected EGUs.

[380] Numerous states submitted comments urging the EPA to allow states to develop trading programs, as suggested in the proposal, including interstate trading programs. They include, for example, Alabama (EPA should develop and issue guidelines that allow options for multi-state plans and interstate credit trading programs, comment 23584), California (EPA should provide flexibility for allowance trading programs to be integrated into state plans, comment 23433), Hawaii (supports use of emission credit trading with other entities to achieve compliance, comment 23121), Massachusetts (EPA should explore possibility of hosting a third-party emissions trading bank that can allow states interested in allowance trading to plug and play in to a wider, more cost-effective market, comment 31910), Michigan (supports emissions trading programs, comment 23987), Minnesota (develop model trading rule that states could incorporate by reference as part of plan and automatically be included in multi-state mass trading program, comment 23987), North Carolina (EPA should examine a system of banking and trading for energy efficiency, comment 23542), Oregon (EPA should expand the explicit options for multi-state plans beyond cap-and-trade, comment 20678), Washington (supporting trading, comment 22764), Wisconsin (requesting EPA to develop a national trading program, Post-111(d) Proposal Questions to EPA WI Questions for 7/16 Hub call).

In addition, several groups of states supported trading programs: Georgetown Climate Center (a group of state environmental agency leaders, energy agency leaders, and public utility commissioners from California, Colorado, Connecticut, Delaware, Illinois, Maine, Maryland, Massachusetts, Minnesota, New Hampshire, New York, Oregon, Rhode Island, Vermont, and Washington) (''We believe states should have maximum flexibility to determine what kinds of collaborations might work for them. These could include submission of joint plans, standardized approaches to trading renewable or energy efficiency credits. . . . We also encourage EPA to help facilitate such interstate agreements or multi-state collaborations by working with states to either identify or provide a platform or framework that states may elect to use for the tracking and trading of avoided generation or emissions credits due to interstate efficiency or renewable energy.'' comment 23597, at 39–40); RGGI (including Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, Vermont) (''[E]very serious proposal to reduce carbon emissions from EGUs, from proposed US legislation to programs in place in California and Europe, has identified allowance trading as the best approach.'' Comment 22395 at 7–8); Western States Center for New Energy Economy (including Arizona, California, Colorado, Idaho, Montana, Nevada, Oregon, South Dakota, Utah, Washington) (''Some degree of RE and EE credit trading among states may support compliance, even in the absence of a comprehensive regional plan. Therefore, EPA should support approaches which allow states flexibility to allocate credit for these zero-carbon resources, along with approaches which allow states to reach agreements on the allocation of carbon liabilities. This includes ensuring that existing tracking mechanisms for renewable energy in the West, such as the Western Renewable Energy Generation Information System (WREGIS), are compatible with the final proposal.'' Comment 21787 at 5); Midcontinent States Environmental and Energy Regulators (including Arkansas, Illinois, Michigan, Minnesota Missouri, Wisconsin) (EPA should also provide states with optional . . . systems (or system) for tracking emissions, allowances, reduction credits, and/or generation attributes that states may choose to use in their 111(d) plans,'' comment 22535 at 3).

In addition, trading programs were supported by, among others, a group of Attorneys General from 11 states and the District of Columbia. Comment 25433 (Attorneys General from New York, California, Connecticut, Maine, Maryland, Massachusetts, New Mexico, Oregon, Rhode Island, Vermont, Washington, District of Columbia, and New York City Corporation Counsel).

Numerous industry commenters also supported trading, including Alliant Energy Corporate Services, Inc. (comment 22934), Calpine (comment 23167), DTE Energy (comment 24061), Exelon (comment 23428 and 23155), Michigan Municipal Electric Association (MMEA) (comment 23297), National Climate Coalition (comment 22910), Pacific Gas and Electric Company (comment 23198), Western Power Trading Forum (WPTF) (comment 22860). Environmental advocates also supported trading, including Clean Air Task Force (comment 22612), Environmental Defense Fund (comment 23140), Institute for Policy Integrity, New York University School of Law (comment 23418).

founded conclusion that it is reasonable for states to incorporate emissions trading in the standards of performance they establish for affected EGUs and that many, if not all, would do so.[381]

Whether viewed from the perspective of an individual EGU or the source category as a whole, emissions trading is thus an integral part of our BSER analysis. Again, we concluded that this is reasonable given the global nature of the pollutant, the transactional and interconnected nature of this industry, and the long history and numerous examples demonstrating that, in this sector, trading is integral to how regulators have established, and sources have complied with, environmental and similar obligations (such as RE standards) when it was appropriate to do so given the program objective. The reasonableness is further demonstrated by the numerous comments (some of which are noted above) from industry, states, and other stakeholders in this rulemaking that supported allowing states to adopt trading programs to comply with section 111(d) and encouraged EPA to facilitate trading across state lines through the use of trading-ready state plans. The EPA's reliance on trading in its BSER determination does not mean, however, that states are required to establish trading programs (just as states are not required to implement the building blocks that comprise BSER). Nor does it mean that trading is the only transactional approach that we could have considered in setting the BSER or that states could use to effectuate the building blocks were they to decide that they did not want to take on the responsibility of running a trading program. Rather, it is simply a recognition of the nature of this industry and the long history of trading as an important regulatory tool in establishing regulatory regimes for this industry and its reasonable availability to states in establishing standards of performance.

As an initial matter, trading is permissible for these emission guidelines because CO_2 is a global pollutant; the location of its emission does not affect the location of the environmental harm it causes. For CO_2, it is the total amount of emissions from the source category that matters, not the specific emissions from any one EGU. The fact that trading allows sources to shift emissions from one location to another does not impede achievement of the environmental goal of reducing CO_2 pollution. In its character as a pollutant whose impacts extend beyond local areas, CO_2 pollution resembles to some extent the regional SO_2 pollution that Congress chose to address with the emissions trading program enacted in Title IV of the 1990 CAA Amendments. The argument in support of trading approaches is even stronger for CO_2 pollution, whose adverse effects are global rather than merely regional like the SO_2 emissions contributing to acid precipitation.

Further, as discussed elsewhere in the preamble, the utility power sector—and the affected EGUs and other generation assets that it encompasses—has a long history of working on a coordinated basis to meet operating and environmental objectives, necessitated and facilitated by the unique interconnectedness and interdependence of the sector. That history includes joint dispatch for economic and reliability purposes, both within large utility systems and in multi-utility power pools that have evolved into RTOs; joint power plant ownership arrangements; and long-term and short-term bilateral power purchase arrangements. More recently, the sector's history also includes emissions trading programs designed by Congress, the EPA, and the states to address regional environmental problems and, most recently, climate change. Examples of such programs are noted below.

Essentially, trading does nothing more than commoditize compliance, with the following two important results emerging from that: It reduces the overall costs of controls and spreads those costs among the entire category of regulated entities while providing a greater range of options for sources that may not want to make on-site investments for controlling their emissions and may prefer to make the same investment, via the purchase of the tradable compliance instrument, at another generating source. Building blocks 2 and 3 entail affected EGUs investing in increased generation from existing NGCC units and RE. The affected EGUs could do so in any number of ways, including acquiring ownership interests in existing NGCC or RE facilities or entering into bilateral transactions with the owners of existing NGCC facilities or RE sources. As discussed elsewhere, it is reasonable to expect that these actions can develop into discrete, tradable commodities (*e.g.,* an ERC) and that liquid markets will develop, which would reduce transaction costs and allow an affected EGU to comply with its emission limits by purchasing discrete units in amounts tailored closely to its compliance needs. The existence of such tradable commodities also incentivizes over-compliance by affected EGUs, which can then sell their over-compliance in the form of ERCs or allowances to other affected EGUs. Moreover, as noted elsewhere, the opportunity to trade is consistent with the EPA's regional approach for the building blocks.

By the same token, the opportunity to trade incentivizes affected EGUs to over-comply with building block 1. Thus, the opportunity to trade supports the EPA's assumptions about what an average affected EGU can achieve with regards to heat rate improvement even if each and every affected EGU cannot achieve that level of improvement. In addition, trading incentivizes affected EGUs to consider low-cost, non-BSER methods to reduce emissions as well, and, as discussed below, there are numerous non-BSER methods, ranging from implementation of demand-side EE programs to natural gas co-firing.

Trading has become an important mechanism for achieving environmental goals in the electricity sector in part because trading allows environmental regulators to set an environmental goal while preserving the ability of the operators of the affected EGUs to decide the best way to meet it taking account of the full range of considerations that govern their overall operations. For example, commenters were concerned that because of building block 2, the emission guidelines would require state environmental regulators to make dispatch decisions for the electricity markets, a role that state environmental regulators do not currently play. Although building block 2 entails substituting existing NGCC generation for steam generation, implementing the emission limits that are based in part on building block 2 through a trading program provides the individual affected EGUs with a great deal of control over their own generation while the industry as a whole achieves the environmental goals. For example, individual steam generators have the option of maintaining their generation as long as they acquire additional ERCs. Moreover, trading provides a way for states to set standards of performance that realize the required emissions reduction without requiring any form of ''environmental dispatch'' because, as many existing trading programs have shown, monetization of the environmental constraint is consistent with a least-cost dispatch system. Trading also supports the EPA's approach to the ''remaining useful life'' provision in section 111(d)(1) because with trading, an affected EGU with a

[381] As discussed in the Legal Memorandum, the EPA has promulgated other rulemakings, including the transport rulemakings—the NO_X SIP Call and CAIR, which required states to submit SIPs, and CSAPR, which allows SIPs—on the premise of interstate emission trading.

limited remaining useful life can avoid the need to implement long-term emission reduction measures and can instead purchase ERCs or other tradable instruments, such as mass-based allowances, thereby allowing the state to meet the requirements of this rule.

The EPA's job in issuing these emission guidelines is to determine the BSER that has been adequately demonstrated and to set emission limitations that are achievable through the application of the BSER and implementable through standards of performance established by the states. The three building blocks are the EPA's determination of what technology is adequately demonstrated. We also consider trading an integral part of the BSER analysis because, in addition to being available to states for incorporation in the standards of performance they set for affected EGUs, trading has been adequately demonstrated for this industry in circumstances where systemic rather than unit-level reductions are central. Congress, the EPA, and state regulators have established successful environmental programs for this industry that allow trading of environmental (or similar) attributes, and trading has been widely used by the industry to comply with these programs. Examples include the CAA Title IV Acid Rain Program, the NO_X SIP Call (currently referred to as the NO_X Budget Trading Program), the Clean Air Interstate Rule (CAIR), the Cross-State Air Pollution Rule (CSAPR),[382] the Regional Haze trading programs, the Clean Air Mercury Rule,[383] RGGI, the trading program established by California AB32, and the South Coast Air Quality Management District RECLAIM program. We describe these programs in section II.E. of this preamble. In addition, we note in the Legal Memorandum accompanying this preamble that Congress, in enacting the Title IV acid rain trading program, and the EPA, in promulgating the regulatory trading programs listed, recognized both the suitability of trading for the EGU industry and the benefits of trading in reducing costs, spreading costs to affected EGUs throughout the sector, and facilitating the ability of affected EGUs to comply with their emission limits. In addition, as we discuss in section V.E. of this preamble, many states have adopted RE standards that promote RE through the trading of renewable energy certificates (RECs).

Based on this history, it is reasonable for the EPA to determine that states can establish standards of performance that incorporate trading and, as a result, for the purpose of making a BSER determination here to evaluate prospective emission control measures in light of the availability of trading. Trading is a regulatory mechanism that works well for this industry. The environmental attributes in the preceding programs (representing emissions of air pollutants) are identical to or similar in nature to the environmental attribute here (CO_2 emissions). The markets for RECs show that robust markets for RE, in particular, already exist.

Given the benefits of trading and the background of multi-unit coordination grounded in the nature of the utility power sector, it is natural for sources and states to look for opportunities to apply similar coordination to a regional problem such as reduction of CO_2 emissions from the sector. As noted earlier, the EPA heard this interest expressed during the outreach process for this rulemaking and saw it reflected in comments on the proposal. Emissions trading was prominent in these expressions of interest; while the proposal allowed trading and encouraged the development of multi-state plans which would allow the benefits of trading to extend over larger regions, we heard that interest was even greater in ''trading-ready'' plans that would use trading mechanisms and market-based coordination, rather than state-to-state coordination, as the primary means of facilitating multi-unit approaches to compliance. The general industry and state preference for multi-unit compliance approaches makes great sense in the context of the industry and this pollutant, as does the specific preference for trading-ready section 111(d) plans, and we have made efforts in the final rule to accommodate trading-ready plans as described in section VIII.

g. *Measures that reduce CO_2 emissions or CO_2 emission rates but are not included in the BSER.* There are numerous other measures that are available to at least some affected EGUs to help assure that they can achieve their emission limits, even though the EPA is not identifying these measures as part of the BSER. These measures include demand-side EE implementable by affected EGUs; new or uprated nuclear generation; renewable measures other than those that are part of building block 3, including distributed generation solar power and off-shore wind; combined heat and power and waste heat power; and transmission and distribution improvements. In addition, a state may implement measures that yield emission reductions for use in reducing the obligations on affected EGUs, such as demand-side EE measures not implementable by affected EGUs, including appliance standards, building codes, and drinking water or wastewater system efficiency measures. The availability of these measures further assures that the appropriate level of emission reductions can be achieved and that affected EGUs will be able to achieve their emission limits.

h. *Ability of EGUs to implement the BSER.* The EPA's analysis, based in part on observed decades-long behavior of EGUs, shows that all types and sizes of affected EGUs in all locations are able to undertake the actions described as the BSER, including investor-owned utilities, merchant generators, rural cooperatives, municipally-owned utilities, and federal utilities. Some may need to focus more on certain measures; for example, an owner of a small generation portfolio consisting of a single coal-fired steam EGU may need to rely more on cross-investment approaches, possibly including the purchase of emission credits or allowances, because of a lack of sufficient scale to diversify its own portfolio to include NGCC capacity and RE generating capacity in addition to coal-fired capacity. As a legal matter, it is not necessary that each affected EGU be able to implement the BSER, but in any event, in this rule, all affected EGUs can do so. Since states can reasonably be expected to establish standards of performance incorporating emissions trading, affected EGUs may rely on emissions trading approaches authorized under their states' section 111(d) plans to, in effect, invest in building block measures that are physically implemented at other locations. As discussed above, the EPA's quantification of the CO_2 emission performance rates in a manner that provides headroom within the BSER also contributes to the ability of all

[382] For example, in CSAPR, which covered the states in the eastern half of the U.S., the EPA assumed the existence of trading across those states in the rule's cost estimates contained in the RIA. ''Regulatory Impact Analysis for the Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone in 27 States; Correction of SIP Approvals for 22 States'' 32 (June 2011), *http://www.epa.gov/airtransport/CSAPR/pdfs/FinalRIA.pdf.* In addition, the rule is being implemented either through federal implementation plans (FIPs) that authorize interstate emission trading or SIPs that authorize interstate emissions trading.

[383] Although the CAMR trading program never took effect because the rule was vacated on other grounds, it consisted of a nationwide trading program that the EPA adopted under CAA section 111(d). Some states declined to allow their sources to participate in the trading program on the grounds that nationwide trading was not appropriate for the air pollutant at issue, mercury, a HAP that caused adverse local impacts.

affected EGUs to implement the BSER and achieve emissions limitations consistent with those performance rates.

i. *Subcategorization.* As noted above, in this rule, we are treating all fossil fuel-fired EGUs as a single category, and, in the emission guidelines that we are promulgating with this rule, we are treating steam EGUs and combustion turbines as separate subcategories. We are determining the BSER for steam EGUs and the BSER for combustion turbines, and applying the BSER to each subcategory to determine a performance rate for that subcategory. We are not further subcategorizing among different types of steam EGUs or combustion turbines. As we discuss below, this approach is fully consistent with the provisions of section 111(d), which simply require the EPA to determine the BSER, do not prescribe the method for doing so, and are silent as to subcategorization. This approach is also fully consistent with other provisions in section 111, which require the EPA first to list source categories that may reasonably be expected to endanger public health or welfare and then to regulate new sources within each such source category, and which grant the EPA discretion whether to subcategorize the sources for purposes of determining the BSER.

As discussed below, each affected EGU can achieve the performance rate by implementing the BSER, specifically, by taking a range of actions—some of which depend on features of the section 111(d) plan chosen by the state, such as the choice of rate-based or mass-based standards of performance and the choice of whether and how to permit emissions trading—including investment in the building blocks, replaced or reduced generation, and purchase of emission credits or allowances. Further, in the case of a rate-based state plan, several other compliance options not included in the BSER for this rule are also available to all affected EGUs, including investment in demand-side EE measures. Such compliance options may also indirectly help affected EGUs achieve compliance under a mass-based plan.

Our approach of subcategorizing between steam EGUs and combustion turbines is reasonable because building blocks 1 and 2 apply only to steam EGUs. Moreover, our approach of not further subcategorizing as between different types of steam EGUs or combustion turbines reflects the reasonable policy that affected EGUs with higher emission rates should reduce their emissions by a greater percentage than affected EGUs with lower emission rates and can do so at a reasonable cost using the approaches we have identified as the BSER as well as other available measures.

Of course, a state retains great flexibility in assigning standards of performance to its affected EGUs and can impose different emission reduction obligations on its sources, as long as the overall level of emission limitation is at least as stringent as the emission guidelines, as discussed below.

3. Changes From Proposal

For the BSER determined in this final rule, based on consideration of comments responding to a broad array of topics considered in the proposal, the EPA has adopted certain modifications to the proposed BSER. In this subsection we describe the most important modifications, including some that relate to individual building blocks and some that are more general. Additional modifications that relate to individual building blocks are discussed in the respective sections for those building blocks below (sections V.C. through V.E.).

We note that taken together, the modifications yield emission reductions requirements that commence more gradually than the proposed goals but are projected to produce greater overall annual emission reductions by 2030.[384] We also note that the modifications lead to requirements that are more uniform across states than the proposed state goals (consistent with the direction of certain alternatives on which we sought comment in the proposal), with the final requirements generally becoming more stringent (compared to the proposal) in states with the highest 2012 CO_2 emission rates and less stringent in states with lower 2012 CO_2 emission rates.

a. *Interpretations of CAA section 111.* In the June 2014 proposal, the EPA proposed interpretations of section 111(a)(1) and (d), and applied these interpretations to existing fossil fuel-fired EGUs.[385] Informed by comments, the EPA has clarified some of these interpretations, and has developed a more refined understanding of how some of these interpretations should be applied. The clarified and more refined interpretations replace the proposed interpretations.

Two of these points merit mention here. First, the EPA is clarifying in this rule that the interpretation of ''system of emission reduction'' does not include emission reduction measures that the states have authority to mandate without the affected EGUs being able to implement the measures themselves (*e.g.,* appliance standards or building codes). In the final rule, we have clarified that the components of the BSER must be implementable by the affected EGUs, not just by the states, and we show that all the components of the BSER have been demonstrated to be achievable on that basis without reliance on actions that can be accomplished only through government mandates. Further discussion of these points can be found throughout this section on the BSER and the following sections on the individual building blocks.

Second, the EPA has adopted a combined interpretation of sections 111(a)(1) and 111(d) that, compared to the proposal, better reflects the historical interpretations of section 111(a)(1), which have generally supported emissions standards that are nationally uniform for sources incorporating a given technology, and gives less weight to the state-focused character of section 111(d), which calls for emissions standards to be implemented through the development of individual state plans. The proposed state goals were heavily (although not entirely) dependent on the emission reduction opportunities available to the EGUs in each individual state, and because the relative magnitudes of these opportunities varied by state, states with similar EGU fleet compositions could have faced state goals of different stringencies, potentially making it difficult for multiple states to set the same standards of performance for affected EGUs using the same technologies (assuming the states were interested in setting standards of performance for their various affected EGUs in such a manner). Some commenters viewed this potential result as inconsistent with section 111(a)(1), inequitable, or both. In response, we took further comment on these potential disparities in the October 30, 2014 NODA. In this final rule, we are obviating those concerns by assessing the emission reduction opportunities at an appropriate regional scale, consistent with alternatives on which we sought comment, and using this regional information to reformulate the proposed emissions standards as nationally

[384] For the proposed rule, the EPA projected total CO_2 emission reductions from 2005 levels of 29% in 2025 and 30% in 2030. For the final rule, the EPA projects total CO_2 emissions reductions from 2005 levels of 28% in 2025 and 32% in 2030. See Regulatory Impact Analysis for the CPP Proposed Rule, Table 3–6, and Regulatory Impact Analysis for the CPP Final Rule, Table 3–6, available in the docket.

[385] The June 2014 proposal in part referenced proposed interpretations of section 111(a)(1) that the EPA explained in the January 2014 proposal to address CO_2 emissions from new fossil fuel-fired EGUs under section 111(b).

uniform emissions standards for the emission guidelines.[386] National uniformity is consistent with prior section 111 rulemaking and advances a number of other goals central to this rulemaking. The methodological refinements related to regional assessment of emission reduction opportunities and the use of uniform emissions standards by technology subcategory are further discussed below.

b. *Approach to quantification of emission reductions from increased RE generation.* In the June 2014 proposal, the EPA described two possible approaches for quantifying the amount of emission reductions achievable from affected EGUs through the use of RE generation. The proposed approach used information on state RPS aggregated at a regional level along with historical RE generation data to project the amount of RE generation used in quantifying the emission reductions achievable through the BSER. The alternative approach used information on the technical and market potential for development of renewable resources in each state to project the RE-related emission reductions. In the October 30, 2014 NODA, we sought comment on an additional approach of aggregating the state-level information to a regional level, as suggested by some commenters. In this final rule we are adopting a combination of these approaches that uses historical RE generating capacity deployment data aggregated to a regional level, supported and confirmed by projections of market potential developed through a techno-economic approach.

In the June 2014 proposal, RE generation was also quantified as generation from total—that is, existing and new—RE generating capacity, a formulation that was consistent with the formulation of most RPS, which are typically framed in terms of total rather than incremental generation. In response to the EPA's request for comment on this approach, commenters observed that the approach was inconsistent with the approach taken for other building blocks, and that generation from RE generating capacity that already existed as of 2012 should not be treated as reducing emissions of affected EGUs from 2012 levels. As just noted, we are not using the RPS-based methodology in the final rule, and we agree with comments that quantification of RE generation on an incremental basis is both more consistent with the treatment of other building blocks and more consistent with the general principle that the BSER should comprise incremental measures that will reduce emissions below existing levels, not measures that are already in place, even if those in-place measures help current emission levels be lower than would be the case without the measures. The final rule therefore defines the RE component of the BSER in terms of incremental rather than total RE generation.[387] Further details regarding the final rule's quantification of RE generation are provided in section V.E. below.

c. *Exclusion from the BSER of emission reductions from use of under-construction or preserved nuclear capacity.* In the June 2014 proposal, the EPA included in building block 3 provisions reflecting the ability for nuclear generation to replace fossil generation and thereby reduce CO_2 emissions at affected EGUs. We proposed to include in building block 3 the potential generation from five under-construction nuclear generating units whose construction had commenced prior to the issuance of the proposal. In addition, to address the potential that some currently operating nuclear facilities may shut down prior to 2030, the proposal incorporated into the BSER for each state with nuclear capacity a projected 5.8 percent reduction in nuclear generation, based on an estimate of potential nationwide loss of nuclear generation from existing units. We sought comment on all aspects of these proposed approaches. While we recognize the important role nuclear power plants have to play in providing carbon-free generation in an all-of-the-above energy system, for this final rule, the BSER does not include either of the components related to nuclear generation.

The EPA received numerous comments on the proposed BSER components related to nuclear power. With respect to generation from under-construction nuclear units, some commenters expressed strong opposition to the inclusion of this generation in the BSER and the setting of state goals, stating that inclusion would result in very stringent state goals for the states where the units are being built and that the inclusion of the generation in the goals is premature because the units' actual completion dates could be delayed. Commenters also stated that inclusion of the under-construction nuclear generation in the BSER would be inequitable because states where the same heavy investment in zero-CO_2 generation was not being made would have relatively less stringent goals.

With respect to generation from existing nuclear units, some commenters stated that our method of accounting for potential unit shutdowns was flawed, observing that even if the prediction of a 5.8 percent nationwide loss of nuclear generation were accurate, the actual shutdowns would occur in a handful of states, resulting in much larger losses of generation in those particular states.

Upon consideration of comments and the accompanying data, the EPA has determined that the BSER should not include either of the components related to nuclear generation from the proposal. With respect to nuclear units under construction, although we believe that other refinements to this final rule would address commenters' concerns that goals for the particular states where the units are located would be overly stringent either in absolute terms or relative to other states, we also acknowledge that, in comparison to RE generating technology, investments in new nuclear units tend to be individually much larger and to require longer lead times. Also, important recent trends evidenced in RE development, such as rapidly growing investment and rapidly decreasing costs, are not as clearly evidenced in nuclear generation. We view these factors as distinguishing the under-construction nuclear units from RE generating capacity, indicating that the new nuclear capacity is likely of higher cost and therefore less appropriate for inclusion in the BSER. Excluding the under-construction nuclear units from the BSER, but allowing emission reductions attributable to generation from the units to be used for compliance as discussed below and in section VIII, will recognize the CO_2 emission reduction benefits achievable through the significant ongoing commitment required to complete these major investments.

With respect to existing nuclear units, although again we believe that other refinements in the final rule would address the concern about disparate impacts on particular states, we acknowledge that we lack information on shutdown risk that would enable us to improve the estimated 5.8 percent factor for nuclear capacity at risk of

[386] Of course, a source in one state may face different requirements than similar sources in other states, depending on whether the state adopts the state measures approach or, if it adopts the emission standards approach, whether it imposes a mass limit or an emission rate and, if the latter, at what level.

[387] Generation from existing RE capacity will continue to make compliance with mass-based standards easier to achieve by making the overall amount of fossil fuel-fired generation that is required to meet the demand for energy services lower than it would otherwise be, thereby keeping CO_2 emissions lower than they would otherwise be.

retirement. Further, based in part on comments received on another aspect of the proposal—specifically, the proposed inclusion of existing RE generation in the goal-setting computations—we believe that it is inappropriate to base the BSER in part on the premise that the preservation of existing low- or zero-carbon generation, as opposed to the production of incremental, low- or zero-carbon generation, could reduce CO_2 emissions from current levels. Accordingly, we have determined not to reflect either of the nuclear elements in the final BSER.

Generation from under-construction or other new nuclear units and capacity uprates at existing nuclear units would still be able to help sources meet emission rate-based standards of performance through the creation and use of credits, as noted in section V.A.6.b. and section VIII.K.1.a.(8), and would help sources meet mass-based standards of performance through reduced utilization of fossil generating capacity leading to reduced CO_2 emissions at affected EGUs. However, consistent with the reasons just discussed for not reflecting preservation of existing nuclear capacity in the BSER—namely, that such preservation does not actually reduce existing levels of emissions from affected EGUs—the rule does not allow preservation of generation from existing or relicensed nuclear capacity to serve as the basis for creation of credits that individual affected EGUs could use for compliance, as further discussed in section VIII.K.1.a.(8).[388]

d. *Exclusion from the BSER of emission reductions from demand-side EE.* The June 2014 proposal included demand-side EE measures in building block 4 as part of the BSER. The EPA took comment on the attributes of each of the proposed building blocks, and building block 4 was a topic of considerable controversy among commenters. While many commenters recognized demand-side EE as an integral part of the electricity system, emphasized its cost-effectiveness as a means of reducing CO_2 emissions from the utility power sector, and strongly supported its inclusion in the BSER, other commenters expressed significant concerns.

As explained in section V.B.3.c.(8) below, our traditional interpretation and implementation of CAA section 111 has allowed regulated entities to produce as much of a particular good as they desire provided that they do so through an appropriately clean (or low-emitting) process. While building blocks 1, 2, and 3 fall squarely within this paradigm, the proposed building block 4 does not. In view of this, since the BSER must serve as the foundation of the emission guidelines, the EPA has not included demand-side EE as part of the final BSER determination.

It should be noted that commenters also took the position that the EPA should allow demand-side EE as a means of compliance with the requirements of this rule, and, as discussed in section V.A.6.b. and section VIII below, we agree.

e. *Consistent regionalized approach to quantification of emission reductions from all building blocks.* In the June 2014 proposal, the EPA treated each of the building blocks differently with respect to the regional scale on which the building block was applied for purposes of assessing the emission reductions achievable through use of that building block. Building block 1 was quantified at a national scale, identifying a single heat rate improvement opportunity applicable on average to all coal-fired steam EGUs. Building block 2 was quantified at the scale of each individual state, considering the amount of generation that could be shifted from steam EGUs to NGCC units within the state, although we solicited comment on considering generation shifts at a broader regional scale. The RE component of building block 3 was quantified at a regional scale using RPS information as a proxy for RE development potential, and the regional results were then applied to each state in the region using the state's baseline data; an alternative methodology on which we requested comment quantified the RE component using a techno-economic approach on a state-specific basis. In the October 2014 NODA, we requested comment on using a techno-economic approach to quantify RE generation potential at a regional scale and took broad comment on strategies for better aligning the BSER with the regionally interconnected electrical grid.[389] We also solicited comment on the appropriate regional boundaries or regional structure to facilitate this approach.

For the final rule, with the benefit of comments received in response to these proposals and alternatives, we have adopted a consistent regionalized approach to quantification of emission reductions achievable through all the building blocks. Under this approach, each of the building blocks is quantified and applied at the regional level, resulting in the computation for each region of a performance rate for steam EGUs and a performance rate for NGCC units. For each of the technology subcategories, we identify the most conservative—that is, the least stringent —of the three regional performance rates. We then apply these least stringent subcategory-specific performance rates to the baseline data for the EGU fleet in each state to establish state goals of consistent stringency across the country. (Note that the actual state goals vary among states to reflect the differences in generation mix among states in the baseline year.) Further description of the steps in this overall process is contained in the preamble sections addressing the individual building blocks (sections V.C., V.D., and V.E.), CO_2 emission performance rate computation (section VI), and state goal computation (section VII), as well as the GHG Mitigation Measures TSD for the CPP Final Rule and the CO_2 Emission Performance Rate and Goal Computation TSD for the CPP Final Rule available in the docket.

Compared to the more state-focused quantification approach selected in the proposal, and as recognized in the NODA, a regionalized approach better reflects the interconnected system within which interdependent affected EGUs actually carry out planning and operations in order to meet electricity demand. We have already discussed the relevance of the interconnected system and the interdependent operations of EGUs as factors supporting consideration of building blocks 2 and 3 as elements of the BSER for this pollutant and this industry, and these same factors support quantifying the emission reductions achievable through building blocks 2 and 3 on a regionalized basis. Because it better reflects how the industry works, a regionalized approach also better represents the full scope of emission reduction opportunities available to individual affected EGUs through the normal transactional processes of the industry, which do not stop at state borders but rather extend throughout these interconnected regions. With respect to building block 1, which comprises types of emission reduction measures that in other rulemakings under CAA section 111 would typically be evaluated on a nationwide basis, for this rule, as discussed in section V.C. below, we are quantifying the emission reductions achievable through building

[388] As with generation from existing RE capacity, generation from existing nuclear capacity will continue to make compliance with mass-based standards easier to achieve by making the overall amount of fossil fuel-fired generation that is required to meet the demand for energy services lower than it would otherwise be, thereby keeping CO_2 emissions lower than they would otherwise be.

[389] 79 FR 64543, 64551–52.

block 1 on a regional basis in order to treat the building blocks consistently and to ensure that for each region the quantification of the BSER represents only as much potential emission reduction from building block 1 as our analysis of historical data indicates can be achieved on average by the affected EGUs in that region.

Characterizing and quantifying the measures included in the BSER on a regional basis rather than a state-limited basis is also appropriate because states can establish standards of performance that incorporate emissions trading, including trading between and among EGUs operating in different states, and thus provide EGUs the opportunity to trade. Emissions trading provides at least one mechanism by which owners of affected EGUs can access any of the building blocks at other locations. With emissions trading, an affected EGU whose access to heat rate improvement opportunities, incremental generation from existing NGCC units, or generation from new RE generating capacity is relatively favorable can overcomply with its own standard of performance and sell rate-based emission credits or mass-based emission allowances to other affected EGUs. Purchase of the credits or allowances by the other EGUs represents cross-investment in the emission reduction opportunities, and such cross-investment can be carried out on as wide a geographic scale as trading rules allow.

The regions we have determined to be appropriate for the regionalized approach in the final rule are the Eastern, Western, and Texas Interconnections.[390] In determining that the appropriate regional level for quantification of the BSER was the level of the interconnection, the EPA considered several factors. First, consistent with our goal of aligning regulation with the reality of the interconnected electricity system, we considered the regional scale on which electricity is actually produced, physically coordinated, and consumed in real time—specifically the Eastern, Western, and Texas Interconnections. The Bulk Power System (BPS) in the contiguous U.S. (including adjacent portions of Canada and Mexico) consists of these three interconnections, which are alternating current (AC) power grids where power flows freely from generating sources to consuming loads. These interconnections are separately planned and operated; they are connected to each other only through low-capacity direct current (DC) tie lines. Each interconnection is managed to maintain a single frequency and to maintain stable voltage levels throughout the interconnection. Physically, each interconnection functions as a large pool, where all electricity delivered to the electric grid flows by displacement over all transmission lines in the interconnection and must be continually balanced with load to ensure reliable electricity service to customers throughout each interconnection. ''Since power flows on all transmission paths, it is not uncommon to find circumstances in which part of a power delivery within one balancing area flows on transmission lines in adjoining areas, or part of a power delivery between two balancing areas flows over the transmission facilities of a third area.'' [391] The interconnections are the ''complex machines'' within which EGUs plan, coordinate, and operate, manifesting a degree of both long-term and real-time interdependence that is unique to this industry. We concluded that, absent a compelling reason to adopt a smaller regional scale for evaluation of CO_2 emission reduction opportunities for the electric power sector—which we have not found, as discussed below—the interconnections should be the regions used for evaluation of the BSER for CO_2 emission reductions from the electric power sector because of the fundamental characteristics of electricity, the industry's basic interconnected physical infrastructure, and the interdependence of the affected EGUs within each interconnection.

Second, we considered whether the interconnection subregions for which various planning and operational functions are carried out by separate institutional actors would represent more appropriate regions than the entire interconnnections, and concluded that they would not. Interconnection planning and management follows the NERC functional model, which defines subregional areas and regional entities within each interconnection for the purposes of balancing generation with load and ensuring that reliability is maintained. While a variety of organizations plan and operate these subregions, those activities always occur in the context of the interconnections, and the subregions cannot be operated autonomously. The need to maintain common frequency and stable voltage levels throughout the interconnections requires constantly changing flows of electricity between the planning and operating subregions within each interconnection.

Because each interconnection is a freely flowing AC grid, any power generated or consumed flows through the entire interconnection in real time; as a result of this highly interconnected nature of the power system, the management of generation and load on the grid must be carefully maintained. This management is carried out principally by subregional entities responsible for the operation of the grid, but this operation must be coordinated in real time to ensure the reliability of the system. Regional operators must coordinate the dispatch of power, not only in their own areas, but also with the other subregions within the interconnection. Although this coordination has always been important, grid planning and management has evolved to be increasingly interconnection-wide, through the development of larger regional entities, such as RTO/ISOs, or large-utility dispatch across multiple balancing areas. As a result, the fact that much of the necessary coordination for the interconnections is performed regionally on a partially decentralized basis (at least in the case of the Eastern and Western Interconnections) or occurs through the operation of automated equipment and the physics of the grid does not render the subregions more relevant than the interconnections as the ultimate regions within which electricity supply and demand must balance.

Moreover, some planning and standard setting activities are undertaken explicitly at the interconnection level. For example, interconnections also have interconnection reliability operating limits (IROLs).[392] A joint FERC–NERC report on the September 8, 2011 Arizona-Southern California outages outlined the importance of IROLs.[393]

[390] The Texas Interconnection encompasses the portion of the Texas electricity system commonly known as ERCOT (for the Electric Reliability Council of Texas). The state of Texas has areas within the Eastern and Western Interconnections as well as the Texas Interconnection.

[391] Casazza, J. and Delea, F., *Understanding Electric Power Systems,* IEEE Press, at 188 (2d ed. 2010).

[392] For example, the Eastern Interconnection has Reliability Standard IRO–006–EAST–1, Transmission Loading Relief Procedure for the Eastern Interconnection, *available at http://www.nerc.com/files/IRO–006–EAST–1.pdf* (providing an ''Interconnection-wide transmission loading relief procedure (TLR) for the Eastern Interconnection that can be used to prevent and/or mitigate potential or actual System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances to maintain reliability of the Bulk Electric System (BES).'').

[393] FERC–NERC, *Arizona-Southern California Outages on September 8, 2011: Causes and*

Continued

The report noted that to ensure the reliable operation of the bulk power system, entities must identify a plan for IROLs to avoid cascading outages. ''In order to ensure the reliable operation of the BPS, entities are required to identify and plan for IROLs, which are SOLs that, if violated, can cause instability, uncontrolled separation, and cascading outages. Once an IROL is identified, system operators are then required to create plans to mitigate the impact of exceeding such a limit to maintain system reliability.'' [394]

Congress recognized the significance of the three interconnections in the American Recovery and Reinvestment Act of 2009 (Recovery Act) when it provided $80 million in funding for interconnection-based transmission planning.[395] In order to fulfill this Congressional mandate, DOE and FERC signed a memorandum of understanding to enumerate their roles ''for activities related to the Resource Assessment and Interconnection Planning project funded by the American Recovery and Reinvestment Act of 2009 (Recovery Act). Among the objectives of the project is to facilitate the development or strengthening of capabilities in each of the three interconnections serving the contiguous lower forty-eight States, to prepare analyses of transmission requirements under a broad range of alternative futures and develop long-term interconnection-wide transmission plans.'' [396] DOE issued awards to five organizations that performed work in the Western, Eastern, and Texas Interconnections to develop long-term interconnection-wide transmission expansion plans.[397]

In Order No. 1000, FERC also took a broader regional view of transmission planning.[398] FERC required each public utility transmission provider to participate in a regional transmission planning process that produces a regional transmission plan. FERC also required neighboring transmission planning regions to coordinate with each other. This interregional coordination includes identifying methods for evaluating interregional transmission facilities as well as establishing a common method or methods of cost allocation for interregional transmission facilities.

In addition to Congressional, DOE, and FERC recognition of the importance of the three interconnections, NERC also considers them to be significant. NERC Organizational Standards ''are based upon certain Reliability Principles that define the foundation of reliability for North American bulk electric systems.'' [399] These principles take a broad view of electric system reliability, considering the reliability of interconnected bulk electric systems. For example, Reliability Principle 1 states, ''Interconnected bulk electric systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC standards.'' [400] NERC took a similarly broad view of system reliability when it delegated its authority to monitor and enforce mandatory reliability standards to a single Regional Entity in both the Western and Texas Interconnections (WECC in the West and the Texas Reliability Entity in the ERCOT region of Texas).[401] Moreover, both WECC and ERCOT have interconnection-wide reliability standards.[402] The Eastern Interconnection has multiple reliability regions with some differences in standards, but power flows and reliability are managed through a single Reliability Coordinator Information System that tracks power flows for all transmission transactions.[403]

The importance that Congress, DOE, FERC, and NERC each place upon the interconnections for electric reliability and operational issues is another factor supporting our decision to set the interconnections as the regional boundaries for the establishment of BSER. The utilization of the three interconnections for both planning and reliability purposes is a clear indication of the importance that electricity system regulators, operators, and industry place upon the interconnections. Those responsible for the electricity system recognize the need to ensure that there is a free flow of electricity throughout each interconnection such that transmission planning and reliability analysis are occurring at the interconnection level. Further, this vigilance with respect to considering reliability from an interconnection-wide basis recognizes that each of the interconnections behaves as a single machine where ''outages, generation, transmission changes, and problems in any one area in the synchronous network can affect the entire network.'' [404] By setting the three interconnections as the regions for purposes of BSER, we are acting consistent with the way in which planning, reliability, and industry experts view the electricity system.

An additional factor weighing against the use of planning or operational subregions of the interconnections as the regions for our BSER analysis for this rule is that the borders of those subregions occasionally change as planning and management functions evolve or as owners of various portions of the grid change affiliations. This is not a merely theoretical consideration; numerous ISO/RTO and other regional boundaries have substantially changed in recent years. For example, in 2012, Duke Energy Ohio and Duke Energy Kentucky integrated into PJM.[405] The following year, in December 2013, Entergy and its six utility operating companies joined MISO, creating the MISO South Region.[406] The integration

Recommendations (Apr. 2012), *available at http://www.ferc.gov/legal/staff-reports/04–27–2012-ferc-nerc-report.pdf.*

[394] FERC–NERC, *Arizona-Southern California Outages on September 8, 2011: Causes and Recommendations,* at 97 (Apr. 2012), *available at http://www.ferc.gov/legal/staff-reports/04–27–2012-ferc-nerc-report.pdf.*

[395] American Reinvestment and Recovery Act of 2009, Title IV, Public Law 111–5 (2009).

[396] Memorandum of Understanding Between the U.S. Department of Energy and the Federal Energy Regulatory Commission, *available at http://www.ferc.gov/legal/mou/mou-doe-ferc.pdf.*

[397] DOE, *Recovery Act Interconnection Transmission Planning, available at http://energy.gov/oe/services/electricity-policy-coordination-and-implementation/transmission-planning/recovery-act.*

[398] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities,* Order No. 1000, FERC Stats. & Regs. ¶ 31,323 (2011), *order on reh'g,* Order No. 1000–A, 139 FERC ¶ 61,132, *order on reh'g,* Order No. 1000–B, 141 FERC ¶ 61,044 (2012), *aff'd sub nom. S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d 41 (D.C. Cir. 2014).

[399] NERC, *Reliability and Market Interface Principles,* at 1, *available at http://www.nerc.com/pa/Stand/Standards/ReliabilityandMarketInterfacePrinciples.pdf.*

[400] NERC, *Reliability and Market Interface Principles,* at 1, *available at http://www.nerc.com/pa/Stand/Standards/ReliabilityandMarketInterfacePrinciples.pdf.*

[401] NERC, *Key Players, available at http://www.nerc.com/AboutNERC/keyplayers/Pages/default.aspx.*

[402] WECC, *Standards, available at https://www.wecc.biz/Standards/Pages/Default.aspx* (last visited July 3, 2015); Texas Reliability Entity, *Reliability Standards, available at http://www.texasre.org/standards_rules/Pages/Default.aspx* (last visited July 3, 2015).

[403] The NERC glossary defines the Reliability Coordinator Information System as the ''system that Reliability Coordinators use to post messages and share operating information in real time.'' NERC, *Glossary of Terms Used in Reliability Standards* (Apr. 20, 2009), *available at http://www.eia.gov/electricity/data/eia411/nerc_glossary_2009.pdf.*

[404] Casazza, J. and Delea, F., *Understanding Electric Power Systems,* IEEE Press, at 159 (2d ed. 2010).

[405] PJM, *Duke Energy Ohio, Inc., and Duke Energy Kentucky, Inc., Successfully Integrated Into PJM* (Jan. 3, 2012), *available at http://www.pjm.com/~/media/about-pjm/newsroom/2012-releases/20120103-duke-ohio-and-kentucky-integrate-into-pjm.ashx.*

[406] *South Region Integration, available at https://www.misoenergy.org/WhatWeDo/StrategicInitiatives/SouthernRegionIntegration/Pages/SouthernRegionIntegration.aspx* (noting that the creation of the MISO South Region ''brought over 18,000 miles of transmission, ~50,000

of MISO South correspondingly led to changes in NERC's regional assessment areas.[407] FERC also recently approved the integration of the Western Areas Power Administration—Upper Great Plains, Basin Electric Power Cooperative, and Heartland Consumers Power District into SPP.[408] Additionally, PacifiCorp and the CAISO recently began operating the western Energy Imbalance Market (EIM).[409] Other entities such as NV Energy, Arizona Public Service Co., and Puget Sound Energy are planning to participate in the EIM in the future.[410] The EIM ''creates significant reliability and renewable integration benefits for consumers by sharing and economically dispatching a broad array of resources.'' [411] This history of changing regional boundaries leads us to the conclusion that selecting smaller regional boundaries for purposes of setting the BSER would merely represent a snapshot of current, changeable regional boundaries. As we have seen with recent, large-scale changes regarding ISO/RTO boundaries and NERC reliability assessment areas, such regions would likely not stand the test of the time, nor would smaller regional boundaries accurately reflect electricity flows on the grid. The EPA believes that the interconnections are the most stable and reasonable regional boundaries for setting BSER.

Third, we considered whether transmission constraints, and the fact that the specific locations of generation resources and loads within each interconnection clearly matter to grid planning and operations, necessitate evaluation of the emission reductions available from the building blocks at scales smaller than the interconnections. We concluded that no reduction in scale was needed due to such constraints. The same industry trends that are reflected in the BSER—the changing efficiencies and mix of existing fossil EGUs and the development of RE throughout each interconnection—as well as the management of the interconnected grid as loads are reduced through EE, which is not reflected in the final BSER, are already driving power system development and are being managed through interconnection-wide planning, coordination and operations, and will continue to be managed in that manner in the future with or without this rule. While electricity supply and demand must be balanced in real time in a manner that observes all security constraints at that point in time, and key aspects of that management are carried out at a subregional scale, the emissions standards established in this rule can be met over longer timeframes through processes managed at larger geographic scales, just as they are today. We believe this rule will reinforce these developments and help provide a secure basis for moving forward. If a local transmission constraint requires that for reliability reasons a higher-emitting resource must operate during a certain period of time in preference to a lower-emitting resource that would otherwise be the more economic choice when all costs are considered, nothing in this rule prevents the higher-emitting source from being operated. If the same transmission constraint causes the same conditions to occur frequently, the extra cost associated with finding alternative ways to reduce emissions will provide an economic incentive for concerned parties to explore ways to relieve the transmission constraint. If relieving the constraint would be more costly than employing alternative measures to reduce emissions, the rule allows parties to pursue those alternative emission reduction measures. Accommodation of intermittent constraints and evaluation of alternatives for relieving or working around them have been routine operating and planning practices within the utility power sector for many years; the rule will not change these basic economic practices that occur today. The 2022–29 schedule for the rule's interim goals and the 2030 schedule for the rule's final goals allow time for planning and investment comparable to the sector's typical planning horizons.

Finally, the EPA also considered whether the smaller geographic scales on which affected EGUs may typically engage in energy and capacity transactions necessitate evaluating the emission reductions available from the building blocks at scales smaller than the interconnections, and again concluded that a smaller scale was not necessary or justified. We first note that electricity trading occurs today throughout the interconnection through RTO/ISO markets and active spot markets, often over large areas such as RTO/ISOs, or managed over large dispatch areas outside RTOs. These trades result in interconnection-wide changes in flow that are managed in real time. Moreover, the exchange of power is not limited to these areas. For example, RTOs regularly manage flows between RTOs, and EGUs near the boundaries of RTOs impact multiple subregions across the interconnections, so that any subregional boundaries that might be evaluated for potential relevance as trading region boundaries will change as conditions and EGU choices change, while interconnection boundaries will remain stable.

In addition, the final rule permits trading of rate-based emission credits or mass-based emission allowances. Emission allowances and other commodities associated with electricity generation activities, such as RECs, which, again, represent investments in pollution control measures, are already traded separately from the underlying electric energy and capacity. There is no reason that whatever geographic limits may exist for electricity and capacity transactions by an affected EGU should also limit the EGU's transactions for validly issued rate-based emission credits or mass-based emission allowances. In fact, as discussed below, the final rule not only allows national trading without regard to the interconnection boundaries, but also includes a number of options that readily facilitate states' and utilities' very extensive reliance on emissions trading. It is appropriate for the rule to take this approach, in part, because the non-local nature of the impacts of CO_2 pollution do not necessitate geographic constraints, and in the absence of a policy reason to constrain the geographic scope of trading, the largest possible scope is the most efficient scope.

f. *Uniform CO_2 emission performance rates by technology subcategory.* In conjunction with the refinements to the interpretations of section 111 reflected in the final rule, the EPA has refined the methodology for applying the BSER to the affected EGUs so as to incorporate performance rates that are uniform across technology subcategories.

megawatts of generation capacity, and ~30,000 MW of load into the MISO footprint.'').

[407] NERC previously included Entergy and its six operating areas as part of the SERC Assessment Areas. NERC, *2014 Summer Reliability Assessment* (May 2014), *available at http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2014SRA.pdf.* ''MISO now coordinates all RTO activities in the newly combined footprint, consisting of all or parts of 15 states with the integration of Entergy and other MISO South entities. This transition has led to substantial changes to MISO's market dispatch, creating the potential for unanticipated flows across the following systems: Tennessee Valley Authority (TVA), Associated Electric Cooperative Inc. (AECI), and Southern Balancing Authority.'' *Id. at 7.*

[408] SPP, *FERC approves Integrates System joining SPP* (Nov. 12, 2014), *available at http://www.spp.org/publications/FERC%20approves%20IS%20membership.pdf.*

[409] NREL, *Energy Imbalance Market, available at http://www.nrel.gov/electricity/transmission/energy_imbalance.html.*

[410] CAISO, *EIM Company Profiles* (May 2015), *available at http://www.caiso.com/Documents/EIMCompanyProfiles.pdf.*

[411] CAISO, *Energy Imbalance Market, available at http://www.caiso.com/informed/pages/stakeholderprocesses/energyimbalancemarket.aspx.*

Specifically, the final rule establishes a performance rate of 1305 lbs. per net MWh for all affected steam EGUs nationwide and a performance rate of 771 lbs. per net MWh for all affected stationary combustion turbines nationwide. The computations of these performance rates and the determinations of state goals reflecting the performance rates are described in sections VI and VII of the preamble, respectively. As described above, in its proposed rule and NODA, the EPA solicited comment on a number of proposals to reflect the regional nature of the electricity system in the methodology for quantifying the emission limitations reflective of the BSER. At the same time, the EPA also consistently emphasized the need for strategies to ensure the achievability and flexibility of the established emission limitations and to increase opportunities for interstate and industry-wide coordination. This modification is consistent with a number of comments we received in response to those proposals. The commenters took the position that the proposed state goals varied too much among states and unavoidably implied, or would inevitably result in, states establishing inconsistent standards of performance for sources of the same technology type in their respective states, which in the commenters' view was not appropriate under section 111.

Having determined to adopt regional alternatives for computing the emission reductions achievable under each building block, the EPA has further determined to exercise discretion not to subcategorize based on the regions, and instead to apply a nationally uniform CO_2 emission performance rate for each source subcategory. Evaluating the emission reduction opportunities achievable through application of the BSER on a broad regionalized basis, which is appropriate for the reasons discussed above, makes it possible to express the degree of emission limitation reflecting the BSER as CO_2 emission performance rates that are uniform for all affected EGUs in a technology subcategory within each region. However, the goals and strategies embodied in the EPA's proposed rule are best effected by setting uniform emission performance rates nationally and not just regionally, as recognized by commenters favoring the use of nationally uniform performance rates by technology subcategory. Nationally uniform emission performance rates create greater parity among the emission reduction goals established for states across the contiguous U.S. and increase the ability of states and affected EGUs to coordinate emission reduction strategies, including through the use of emission trading mechanisms if states choose to allow such mechanisms, which we consider likely.

Having determined that the performance rates computed on a regional basis merit consideration as nationally applicable performance rates, we are also determining that the objectives of achievability and flexibility would best be met by using the least stringent of the regional performance rates for the three interconnections for each technology subcategory as the basis for nationally uniform performance rates for that technology subcategory rather than by using the most stringent of the regional performance rates.[412] Under this approach, the CO_2 emission performance rate reflecting the BSER for all steam EGUs is uniform across the contiguous U.S., regardless of the state or interconnection where the steam EGUs are located. While it is true that steam EGUs in the Western and Texas Interconnections have opportunities to implement the measures in the building blocks to a greater extent than the steam EGUs in the Eastern Interconnection—for example, under building block 2, they have relatively greater amounts of incremental NGCC generation available to replace their generation in all years for which performance rates were computed—we do not conclude that this means that the EGUs in all three interconnections should be assigned the most stringent CO_2 emission performance rate computed for any of the three regions. Applying nationally the performance rate computed for the interconnection with the lease stringent rate ensures that the emission limitations are achievable by the affected EGUs in all three interconnections. The use of a common CO_2 emission performance rate across all of the steam EGUs in all three regions also allocates the burdens of the BSER equally across the steam EGU source subcategory. The same is true for the combustion turbine source subcategory, even though, in any year for which emission performance rates are computed, the combustion turbines in two of the interconnections have relatively greater opportunities to replace their generation with generation from new RE generating capacity than combustion turbines in the third interconnection.[413]

In addition, using the least stringent rate provides greater ''headroom''—that is, emission reduction opportunities beyond those reflected in the performance rates—to affected EGUs in the interconnections that do not set the nationwide level. This greater ''headroom'' provides greater nationwide compliance flexibility and assurance that the standards set by the states based on the emission guidelines will be achievable at reasonable cost and without adverse impacts on reliability. This is because affected EGUs in the interconnections that do not set the nationwide level have more opportunities to directly invest in each of the building blocks in their respective regions, and affected EGUs in the interconnection that does set the nationwide level may in effect invest in the opportunities in the other interconnections through trading. At the same time, our approach still represents the degree of emission limitation achievable through use of an appropriately large and diverse set of emission reduction opportunities and can therefore reasonably be considered the ''best'' system of emission reduction for each technology subcategory.

Our approach in this rulemaking thus not only addresses the comments we received regarding potentially disparate impacts of the approach presented in the proposal, it is also generally consistent with the approach we have taken in other NSPS rulemakings, where standards of performance or emission guidelines have typically been established at uniform stringencies for all units in a given source subcategory, and where once the best system of emission reduction has been identified, stringencies are generally set based on what is reasonably achievable using that system.

[412] The Eastern, Western, and Texas Interconnections each encompass large and diverse populations of EGUs with numerous and diverse opportunities to reduce CO_2 emissions through application of the measures in each of the three building blocks. Based on these considerations of scale and diversity, we conclude that each of the interconnections is sufficiently representative of the source subcategories and emission reduction opportunities encompassed in the BSER to potentially serve as the basis for CO_2 emission performance rates applicable to the respective source subcategories on a nationwide basis.

[413] As discussed in section VI and the CO_2 Emission Performance Rate and State Goal Computation TSD, the emission performance rates for each technology subcategory are computed by region for each year from 2022 through 2030, and the region with the least stringent emission rate for a particular subcategory, whose rate therefore is used for all three regions, can differ across years. In the case of the steam EGU subcategory, the nationwide rate for all years is the rate computed for the Eastern Interconnection. In the case of the NGCC subcategory, the nationwide rate is the rate computed for the Texas Interconnection for the years from 2022 through 2026 and the rate computed for the Eastern Interconnection for the years from 2027 through 2030.

Providing each state with a state-specific weighted average rate-based goal allows the state to determine how the emission reduction requirements should be allocated among the state's affected EGUs. We continue to believe that, as in the proposal, this is an important source of flexibility for states in developing their section 111(d) plans. Accordingly, in this final rule we are providing uniform CO_2 emission performance rates for each source subcategory and also translating those rates to state-specific weighted average rate-based goals. For additional flexibility, we are also translating the state-specific rate-based goals into state-specific mass-based goals. Our determinations of the emission performance rates are described in section VI below, and our determinations of the rate-based and mass-based state goals are described in section VII below.

We note here that the weighted-average state goals reflect the application of the uniform CO_2 emission performance rates for affected steam EGUs and affected NGCC units to the respective units in each subcategory in each state. Each state goal therefore reflects uniform stringency of emission reduction requirements with respect to affected units in each source subcategory, but also reflects the EGU fleet composition and historical generation specific to that particular state. Compared to the computation approach reflected in the proposed state goals, the revised approach to quantify the BSER on a regional basis and to translate the results into nationally uniform emission performance rates by source subcategory results in more stringent goals (compared to the proposal) for states whose generation has historically been most heavily concentrated at coal-fired steam EGUs. This shift is an expected consequence of the use of uniform performance rates by source subcategory. At proposal, these states' goals reflected artificial assumptions in the selected goal quantification methodology that to a considerable extent limited their emission reduction opportunities based on their states' borders, and the proposed goals therefore were less stringent in states which had substantial coal generation and little local NGCC capacity. The final rule more realistically recognizes that emission reduction opportunities, like other aspects of the interconnected electricity system, are regional and are not constrained by state borders. The final rule also reflects the EPA's emphasis in the proposal on ensuring the achievability and flexibility of the emission guidelines and increasing opportunities for interstate and industry-wide coordination. We consequently apply the same emission performance rates to coal-fired units in states with heavy reliance on coal-fueled generation as we do to coal-fired units in other states, which produces more stringent state goals than at proposal for the states with the highest concentrations of coal-fired generation. At the same time, the final goals for some states are less stringent than their proposed goals. For example, a goal based on the least stringent regional rates is less stringent for some states than a goal based on state-specific emission reduction opportunities would be. Accordingly, the differences among the final state goals are generally smaller than the differences among the proposed state goals. All of the final rate-based state goals are necessarily in the range bounded by the CO_2 emission performance rate for NGCC units and the CO_2 emission performance rate for steam EGUs because all of the state goals are computed as a weighted average of those two performance rates, and this range is narrower than the range of state goals in the proposal.

The computations of the uniform CO_2 emission performance rates are shown in the CO_2 Emission Performance Rate and Goal Computation TSD for the CPP Final Rule. These uniform emission performance rates are applicable to the states and areas of Indian country [414] located in the contiguous U.S. that have affected EGUs.[415] We have not in this rule applied the uniform emission performance rates to Alaska, Hawaii, Puerto Rico, or Guam—states and territories that have otherwise affected EGUs but are isolated from the three major interconnections—and will determine how to address the requirements of section 111(d) with respect to these jurisdictions at a later time. Further discussion regarding the isolated jurisdictions can be found in section VII.F. of the preamble.

g. *Establishment of a 2022–2029 interim compliance period.* The June 2014 proposal separately quantified emission limitations applicable to an interim 2020–29 period and to the period beginning in 2030. The EPA took broad comment on this proposed timing. Although the proposal provided flexibility in the timing with which emission reductions could be made over the course of the 2020–2029 period in order to achieve compliance with the emission limitations applicable to that interim period, many commenters perceived the start of the period as too soon and stated that it provided insufficient time for planning and investments necessary for sources to begin implementation activities while maintaining reliable electricity supplies.

The EPA has considered these comments and in the final rule has established an interim compliance period of 2022–2029, providing two additional years for planning and investment before the start of compliance. We are persuaded by comments and by our own further analysis that this timeframe is appropriate and will, in combination with the glide path of emission reductions reflected in the final building blocks and the states' flexibility to define their own paths of emission reductions over the interim period (as discussed in section VIII), provide adequate time for necessary planning and investment activities. This will enable the final rule's requirements to be implemented in an orderly manner while reliability of electricity supplies is maintained. Further discussion is provided in the sections of the preamble addressing the individual building blocks (sections V.C., V.D., and V.E.) and on electricity system reliability (section VIII.G.2.).

The initial compliance date of 2022, coupled with the fact that the 2030 standard is phased in over the subsequent eight years, affords affected EGUs the benefit of having an extended planning period before they need to incur any significant obligations. Where needed, states may take the period through September 2018 to develop their final plans, and affected EGUs will be able to work with the states during that period to develop compliance approaches. States will also have the flexibility to select their own emissions trajectories in such a way that certain emission reduction measures could be implemented later in the interim period (again, provided that their affected EGUs still meet the interim performance rates or interim goal over the interim period as a whole). As a result, if the affected EGUs in those states need to incur any expenses before the adoption of the final state plans, those expenses need not be more than minimal. It is worth noting that an earlier state plan submission date provides regulated sources with more certainty and time to

[414] As explained in section III.A. above, an Indian tribe whose area of Indian country has affected EGUs will have the opportunity but not the obligation to seek authority to develop and implement a section 111(d) plan. If no tribal plan is approved, the EPA has the responsibility to establish a plan if it determines that such a plan is necessary or appropriate.

[415] As noted earlier, there are currently no affected EGUs in Vermont or the District of Columbia.

plan for compliance, but has no effect on the time when compliance must be achieved, as the mandatory compliance period begins in 2022 for all states. Some states that already have established programs for limiting CO_2 emissions from power plants may adopt and submit to the EPA state plans by September 6, 2016. In those states, sources will already have developed compliance approaches to meet state law requirements. Other states that submit plans by September 6, 2016, may be expected to work with their affected EGUs to determine a reasonable compliance approach, in light of the fact that compliance is not required to begin until 2022. It is also possible that some states will submit neither final state plans nor initial submittals by September 6, 2016, and that the EPA will promulgate federal plans. Sources in those states will have more than five years to meet their 2022 compliance obligations, a lengthy period that will afford them the opportunity to plan before incurring significant expenditures.

These periods of time are consistent with current industry practice in changing generation or adding new generation. For example, in June 2015, Alabama Power Company announced plans to acquire 500 MW of RE generation over the next six years. This amount would make up between four and five percent of Alabama Power's generation mix.[416] In addition, the study of utility IRPs placed in the docket for this rulemaking[417] shows that sources are able to replace coal-fired generation with natural-gas fired generation and add incremental amounts of RE (as well as take other actions, such as implement demand-side EE programs), on a gradual basis, after a several-year lead time, over an extended period, as provided for under the final rule.

h. *Refinements to stringency for individual building blocks.* For each individual building block, the EPA has reexamined the data and assumptions used at proposal in light of comments solicited and has made a number of refinements in the final rule based on that information. The refinements are discussed in the preamble sections for each building block (sections V.C., V.D., and V.E.) and emission performance rate computation (section VI) and in the GHG Mitigation Measures TSD for the CPP Final Rule and the CO_2 Emission Performance Rate and Goal Computation TSD for the CPP Final Rule. As previously noted, viewed in terms of projected nationwide emission reductions (but not necessarily with respect to each individual state), these refinements generally tend to make the interim goals somewhat less stringent than at proposal and the 2030 goals somewhat more stringent than at proposal. In addition to the changes described above, the refinements include the following:

• Use of regional rates ranging from 2.1 percent to 4.3 percent (rather than 6 percent) as the average heat rate improvement opportunity achievable by steam units under building block 1.

• Use of 75 percent of summer capacity (rather than 70 percent of nameplate capacity) as the target capacity factor for existing NGCC units under building block 2.

• Use of updated information from the National Renewable Energy Laboratory (NREL) on RE costs and potential, and revision of the list of quantified RE technologies to exclude landfill gas under building block 3.

4. Determination of the BSER

In this rule, the EPA is finalizing as the BSER a combination of building blocks 1, 2, and 3, with refinements as discussed below. The building blocks constitute the BSER from the perspective of the source category as a whole. Each building block can be implemented through standards of performance set by the states and includes a set of actions that individual sources can use to achieve the emission limitations reflecting the BSER. These actions and mechanisms, which include reduced generation and emissions trading approaches where the state-set standards of performance incorporate trading and which may be understood as part of the BSER, will be discussed below in section V.A.5. Each of the building blocks consists of measures that the source category and individual affected EGUs have already demonstrated the ability to implement. In quantifying the application of each building block, the EPA has identified reasonable levels of stringency rather than the maximum possible levels.

As discussed above, one of the modifications being made in this rule is the establishment of uniform performance rates by technology subcategory, which enhances the rule's achievability and flexibility and facilitates coordination among the states and across the industry. However, in the first instance, the emission reductions achievable through use of the building blocks are being evaluated on a regional basis that reflects the regional nature of the interconnected electricity system and the region-wide scope of opportunities available for affected EGUs to access emission reduction measures. The EPA recognizes that the emission reduction opportunities under these building blocks vary by region because of regional differences in the existing mix of types of fossil fuel-fired EGUs and the available opportunities to increase low- and zero-carbon generation. Consequently, in order to achieve uniform performance rates by technology subcategory, while respecting these regional differences in emission reduction opportunities, we have determined that it is reasonable not to establish the stringency of the BSER separately by region based on the maximum emission reduction that would be achievable in that region, but instead to establish uniform stringency across all regions at a level that is achievable at reasonable cost in any region. Thus, for each technology subcategory, the BSER is the combination of the elements described above at the combined stringency that is reasonably achievable in the region where the CO_2 emission performance rates determined to be achievable at reasonable cost by the EGUs in that subcategory through application of the building blocks were least stringent.[418]

This approach is consistent with the EPA's efforts to enhance the achievability and flexibility of the rule and to promote interstate and industry coordination and reflects the regional strategies emphasized in the proposal and the NODA. It is also consistent with the approach we have taken in other NSPS rulemakings, where the degree of emission limitation achievable through

[416] Alabama Power Co., "Petition for a Certificate of Convenience and Necessity," submitted to the Alabama Public Service Commission (June 25, 2015) (petition requests "a certificate of convenience and necessity for the construction or acquisition of renewable energy and environmentally specialized generating resources and the acquisition of rights and the assumption of payment obligations under power purchase arrangements pertaining to renewable energy and environmentally specialized generating resources, together with all transmission facilities, fuel supply and transportation arrangements, appliances, appurtenances, equipment, acquisitions and commitments necessary for or incident thereto") (included in the docket for this rulemaking). *See* Swartz, Kristi, "Alabama Power plan would dramatically boost its renewables portfolio," E&E Publishing, July 16, 2015.

[417] See memorandum entitled "Review of Electric Utility Integrated Resource Plans" (May 7, 2015) available in the docket.

[418] The determinations of stringency for each source subcategory were made independently for each year from 2022 through 2030, and in the case of the NGCC category, the limiting region changed over time. Thus, for the NGCC category, the uniform CO_2 emission performance rate is based on the stringency achievable in the Texas Interconnection for the years from 2022 through 2026 and the stringency achievable in the Eastern Interconnection for the years from 2027 through 2030. For the steam EGU subcategory, the uniform CO_2 emission performance rate is based on the stringency achievable in the Eastern Interconnection in all years.

the application of the BSER for each subcategory of affected sources generally has been determined not on the basis of what is achievable by the sources that can reduce emissions most easily, but instead on the basis of what is reasonably achievable through the application of the BSER across a range of sources. This approach also provides compliance headroom—in addition to the headroom provided by our approach to setting the stringency for each individual building block—for affected EGUs in regions where additional emission reductions can be achieved at reasonable cost, thereby promoting nationwide compliance flexibility. Further, because we are authorizing states to establish standards of performance that incorporate trading without geographic restrictions, the opportunity of affected EGUs to engage in emissions trading, to the extent allowed under the relevant section 111(d) plans, ensures the availability of additional, lower-cost emission reduction opportunities in other regions that will also promote compliance flexibility and reduce compliance costs.

As discussed in section XI of the preamble and the Regulatory Impact Analysis, application of the BSER determined as summarized above is projected to result in substantial and meaningful reductions of CO_2 emissions.

Briefly, the elements of the BSER are:

Building block 1: Improving heat rate at affected coal-fired steam EGUs in specified percentages.

Building block 2: Substituting increased generation from existing affected NGCC units for generation from affected steam EGUs in specified quantities.

Building block 3: Substituting generation from new zero-emitting RE generating capacity for generation from affected EGUs in specified quantities.

a. *Building block 1.* Building block 1—improving heat rate at affected coal-fired steam EGUs—is a component of the BSER with respect to coal-fired steam EGUs [419] because the measures the affected EGUs may undertake to achieve heat rate improvements are technically feasible and of reasonable cost, and perform well with respect to other factors relevant to a determination of the ''best system of emission reduction . . . adequately demonstrated.'' Building block 1 is a ''system of emission reduction'' for steam EGUs because owners of these EGUs can take actions that will improve their heat rates and thereby reduce their rates of CO_2 emissions with respect to generation.

The EPA has analyzed the technical feasibility, costs, and magnitude of CO_2 emission reductions achievable through heat rate improvements at coal-fired steam EGUs based on engineering studies and on these EGUs' reported operating and emissions data. We conclude that taking action to improve heat rates is a common and well-established practice within the industry that is capable of achieving meaningful reductions in CO_2 emissions at reasonable cost, although, as discussed earlier, we also conclude that the quantity of emission reductions achievable through heat rate improvement measures is insufficient for these measures alone to constitute the BSER. Specifically, we have determined that an average heat rate improvement ranging from 2.1 to 4.3 percent by all affected coal-fired EGUs, depending on the region, is an element of the BSER, based on the inclusion of those amounts of improvement in the three regions, determined through our regional analysis. Our analysis and conclusions are discussed in Section V.C. below and in the GHG Mitigation Measures TSD for the CPP Final Rule. Additional analysis and conclusions with respect to cost reasonableness are discussed in section V.A.4.d. below.

Consideration of other BSER factors also favors a conclusion that building block 1 is a component of the BSER. For example, with respect to non-air health and environmental impacts, heat rate improvements cause fuel to be used more efficiently, reducing the volumes of, and therefore the adverse impacts associated with, disposal of coal combustion solid waste products. By definition, heat rate improvements do not cause increases in net energy usage. Although we are justifying building block 1 as part of the BSER without reference to technological innovation, we also consider technological innovation in the alternative, and we note that building block 1 encourages the spread of more advanced technology to EGUs currently using components with older designs.

As noted in the June 2014 proposal, the EPA is concerned about the potential ''rebound effect'' associated with building block 1 if applied in isolation. More specifically, we noted that in the context of the integrated electricity system, absent other incentives to reduce generation and CO_2 emissions from coal-fired EGUs, heat rate improvements and consequent variable cost reductions at those EGUs would cause them to become more competitive compared to other EGUs and increase their generation, leading to smaller overall reductions in CO_2 emissions (depending on the CO_2 emission rates of the displaced generating capacity). Unless mitigated, the occurrence of a rebound effect would reduce the emission reductions achieved by building block 1, exacerbating the inadequacy of emission reductions that is the basis for our conclusion that building block 1 alone would not represent the BSER for this industry. However, we believe that our concern about the potential rebound effect can be readily addressed by ensuring that the BSER also reflects other CO_2 reduction strategies that encourage increases in generation from lower- or zero-carbon EGUs, thereby allowing building block 1 to be considered an appropriate part of the BSER for CO_2 emissions at affected EGUs as long as the building block is applied in combination with other building blocks.

b. *Building block 2.* Building block 2—substituting generation from less carbon-intensive affected EGUs (specifically ''existing'' NGCC units, meaning units that were operating or had commenced construction as of January 8, 2014) for generation from the most carbon-intensive affected EGUs—is a component of the BSER for steam EGUs because generation shifts that will reduce the amount of CO_2 emissions at higher-emitting EGUs and from the source category as a whole are technically feasible, are of reasonable cost, and perform well with respect to other factors relevant to a determination of the ''best system of emission reduction . . . adequately demonstrated.'' Building block 2 is a ''system of emission reduction'' for steam EGUs because incremental generation from existing NGCC units will result in reduced generation and emissions from steam EGUs, and owners of steam EGUs can, and many do, invest in incremental generation from NGCC units through a variety of possible mechanisms. A steam EGU investing in incremental generation from NGCC units may choose to reduce its own generation or may maintain its generation level and choose to allow the reduction in generation to occur at other steam EGUs through the coordinated planning and operation of the interconnected electricity system. An

[419] For the reasons discussed in the proposal, the EPA is not determining that heat rate improvements at other types of affected EGUs, such as NGCC units and oil-fired and natural gas-fired steam EGUs, are components of the BSER. However, all types of affected EGUs would be able to employ heat rate improvements as measures to help achieve compliance with their assigned standards of performance.

affected EGU may also invest in emission reductions from building block 2 through the mechanism of engaging in emissions trading where the EGU is operating under a standard of performance that incorporates trading.

The EPA's analysis and conclusions regarding the technical feasibility, costs, and magnitude of CO_2 emission reductions achievable at high-emitting EGUs through generation shifts to lower-emitting affected EGUs are discussed in Section V.D. below. Additional analysis and conclusions with respect to cost reasonableness are discussed in section V.A.4.d. below. We consider generation shifts among the large number of diverse EGUs that are linked to one another and to customers by extensive regional transmission grids to be a routine and well-established operating practice within the industry that is used to facilitate the achievement of a wide variety of objectives, including environmental objectives, while meeting the demand for electricity services. In the interconnected and integrated electricity industry, fossil fuel-fired steam EGUs are able to reduce their generation and NGCC units are able to increase their generation in a coordinated manner through mechanisms—in some cases centralized and in others not—that regularly deal with such changes on both a short-term and a longer-term basis. Our analysis demonstrates that the emission reductions that can be achieved or supported by such generation shifts are substantial and of reasonable cost. Further, both the achievability of this building block and the reasonableness of its costs are supported by the fact that there has been a long-term trend in the industry away from coal-fired generation and toward NGCC generation for a variety of reasons.

Building block 2 is adequately demonstrated as a ''system of emission reduction'' for affected steam EGUs. As discussed in section V.B., since the time of the 1970 CAA Amendments, the utility power sector has recognized that generation shifts are a means of controlling air pollutants; in the 1990 CAA Amendments, Congress recognized that generation shifts among EGUs are a means of reducing emissions from this sector; and generation shifts similarly have been recognized as a means of reducing emissions under trading programs established by the EPA to implement the Act's provisions. It is common practice in the industry to account for the cost of emission allowances as a variable cost when making security-constrained, cost-based dispatch decisions; doing so integrates generation shifts into the operating practices used to achieve compliance with environmental requirements in an economical manner. These industry trends are further discussed in section V.D. Thus, legislative history, regulatory precedent, and industry practice support interpreting the broad term ''system of emission reduction'' as including substituting lower-emitting generation for higher-emitting generation through generation shifts among affected EGUs.

An important additional consideration supporting the determination that building block 2 is adequately demonstrated as a ''system of emission reduction'' is that owners of affected steam EGUs have the ability to invest in generation shifts as a way of reducing emissions. The owner of an affected EGU could invest in such generation shifts in several ways, including by increasing operation of an NGCC unit that it already owns or by purchasing an existing NGCC unit and increasing operation of that unit. Increases in generation by NGCC units over baseline levels can also serve as the basis for creation of CO_2 ERCs—that is, instruments representing the ability of incremental electricity generated by NGCC units to cause emission reductions at affected steam EGUs, as distinct from the incremental electricity itself. Again, it is important to note that the acquisition of such ERCs represents an investment in the actions of the facility or facilities whose alteration of utilization levels generated the emissions rate improvement or reduction. In the context of the BSER, purchase of instruments representing the emissions-reducing benefit of an action is simply a medium of investment in the underlying emissions reduction action. These mechanisms are discussed further in section V.A.5. In this rule, the EPA is establishing minimum criteria for the creation of valid ERCs by NGCC units and for the use of such ERCs by affected steam EGUs for demonstrating compliance with emission rate-based standards of performance established under state plans. The existence of minimum criteria will ensure that crediting mechanisms are feasible and will facilitate the development of organized markets to simplify the process of buying and selling ERCs. The minimum criteria are discussed in section VIII of this preamble.

We note that an affected EGU investing in building block 2 to reduce emissions may, but need not, also choose to reduce its own generation as part of its approach for meeting the standard of performance assigned to it by its state. Through the coordinated operation of the integrated electricity system, subject to the collective emission reduction requirements that will be imposed on affected EGUs in order to meet the emissions standards representing the BSER, an increase in NGCC generation will be offset elsewhere in the interconnection by a decrease in other generation. Because of the need to meet the collective emission reduction requirements, the decrease in generation resulting from that coordinated operation is most likely to be generation from an affected steam EGU. Measures taken by affected EGUs that result in emission reductions from other EGUs in the source category may appropriately be deemed measures to implement or apply the ''system of emission reduction'' of substituting lower-emitting generation for higher-emitting generation.

Consideration of other BSER factors also supports a determination to include building block 2 as a component of the BSER. For example, we expect that building block 2 would have positive non-air health and environmental impacts. Coal combustion for electricity generation produces large volumes of solid wastes that require disposal, with some potential for adverse environmental impacts; these wastes are not produced by natural gas combustion. The intake and discharge of water for cooling at many EGUs also carries some potential for adverse environmental impacts; NGCC units generally require less cooling water than steam EGUs.[420] With respect to energy impacts, building block 2 represents replacement of electrical energy from one generator with electrical energy from another generator that consumes less fuel, so the overall energy impact should be a reduction in fuel consumption by the overall source category as well as by individual affected coal-fired steam EGUs. Although for purposes of this rule we consider the incentive for technological innovation only in the alternative, we note that building block 2 promotes greater use of the NGCC technology installed in the existing fleet of NGCC units, which is newer and more advanced than the technology installed in much of the older existing fleet of steam EGUs. For all these reasons, the

[420] For example, according to a DOE/NETL study, the relative amount of water consumption for a new pulverized coal plant is 2.5 times the consumption for a new NGCC unit of similar size. ''Cost and Performance Baseline for Fossil Energy Plants: Volume 1: Bituminous Coal and Natural Gas to Electricity,'' Rev 2a, September 2013, National Energy Technology Laboratory Report DOE/NETL–2010/1397. EPA believes the difference would on average be even more pronounced when comparing existing coal and NGCC units.

measures in building block 2 qualify as a component of the ''best system of emission reduction . . . adequately demonstrated.''

It should be observed that, by definition of the elements of this building block, the shifts in generation taking place under building block 2 occur entirely among existing EGUs subject to this rulemaking.[421] Through application of this building block considered in isolation, some affected EGUs—mostly coal-fired steam EGUs—would reduce their generation and CO_2 emissions, while other affected EGUs—NGCC units—would increase their generation and CO_2 emissions. However, because for each MWh of generation, NGCC units produce fewer CO_2 emissions than coal-fired steam EGUs, the total quantity of CO_2 emissions from all affected EGUs in aggregate would decrease without a reduction in total electricity generation. In the context of the integrated electricity system, where the operation of affected EGUs of multiple types is routinely coordinated to provide a highly substitutable service, and in the context of CO_2 emissions, where location is not a consideration (in contrast with other pollutants), a measure that takes advantage of that integration to reduce CO_2 emissions from the overall set of affected EGUs is readily understood as a means to implement a ''system of emission reduction'' for CO_2 emissions at affected EGUs even if the measure would increase CO_2 emissions from a subset of those affected EGUs. Indeed, some industry participants are already moving in this direction for this purpose (while other participants are moving in the same direction for other purposes). Standards of performance that incorporate emissions trading can facilitate the implementation of such a ''system'' and such approaches have already been used in the electricity industry to address CO_2 as well as other pollutants, as discussed above.

c. *Building block 3.* Building block 3—substituting generation from expanded RE generating capacity for generation from affected EGUs—is a component of the BSER because the expansion and use of renewable generating capacity to reduce emissions from affected EGUs is technically feasible, is of reasonable cost, and performs well with respect to other factors relevant to a determination of the ''best system of emission reduction . . . adequately demonstrated.'' Building block 3 is a ''system of emission reduction'' for all affected EGUs because incremental RE generation will result in reduced generation and emissions from affected EGUs, and owners or operators of affected EGUs can apply or implement building block 3 through a number of actions. For example, they can invest in incremental RE generation either directly or through the purchase of ERCs. An affected EGU investing in incremental RE generation may choose to reduce its own generation by a corresponding amount or may choose to allow the reduction in generation to occur at other affected EGUs through the coordinated planning and operation of the interconnected electricity system. An affected EGU can also invest in RE generation by means of engaging in emissions trading where the EGU is operating under a standard of performance that incorporates trading.

The EPA's analysis and conclusions regarding the technical feasibility, costs, and magnitude of the measures in building block 3 are discussed in Section V.E. below. Additional analysis and conclusions with respect to cost reasonableness are discussed in section V.A.4.d. below. We consider construction and operation of expanded RE generating capacity to be proven, well-established practices within the industry consistent with recent industry trends. States are already pursuing policies that encourage production of greater amounts of RE, such as the establishment of targets for procurement of renewable generating capacity. Moreover, as discussed earlier, markets are likely to develop for ERCs that would facilitate investment in increased RE generation as a means of helping sources comply with their standards of performance; indeed, markets for RECs, which similarly facilitate investment in RE for other purposes, are already well-established. As noted in Section V.A.5. below, an allowance system or tradable emission rate system would provide incentives for affected EGUs to reduce their emissions as much as possible where such reductions could be achieved economically (taking into account the value of the emission credits or allowances), including by substituting generation from new RE generating capacity for their own generation, or could provide a mechanism, as stated above, for such sources to invest in or acquire such generation.

Building block 3 is adequately demonstrated as a ''system of emission reduction'' for all affected EGUs. As discussed in section II, RE generation has been relied on since the 1970s to provide energy security by replacing some fossil fuel-fired generation. Both Congress and the EPA have previously established frameworks under which RE generation could be used as a means of achieving emission reductions from the utility power sector, as discussed in section V.B. Investment in RE generation has grown rapidly, such that in recent years the amount of new RE generating capacity brought into service has been comparable to the amount of new fossil fuel-fired capacity. Rapid growth in RE generation is projected to continue as costs of RE generation fall relative to the costs of other generation technologies. These trends are further discussed in section V.E. Interpretation of a ''system of emission reduction'' as including RE generation for purposes of this rule is thus supported by legislative history, regulatory precedent, and industry practice.

Also supporting the determination that building block 3 is adequately demonstrated as a ''system of emission reduction'' is the fact that owners of affected EGUs have the ability to invest in RE generation as a way of reducing emissions. As with building block 2, this can be accomplished in several ways. For example, the owner of an affected EGU could invest in new RE generating capacity and operate that capacity in order to obtain ERCs. Alternatively, the affected EGU could purchase ERCs created based on the operation of an unaffiliated RE generating facility, effectively investing in the actions at another site that allow CO_2 emission reductions to occur. These mechanisms are discussed further in section V.A.5. As with building block 2, in this rule the EPA is establishing minimum criteria for the creation of valid ERCs by new RE generators and for the use of such ERCs by affected EGUs for demonstrating compliance with emission rate-based standards of performance established under state plans. The existence of minimum criteria will ensure that crediting mechanisms are feasible and will facilitate the development of organized markets to simplify the process of buying and selling credits. The minimum criteria are discussed in section VIII of the preamble.

As with building block 2, an affected EGU investing in building block 3 to reduce emissions may, but need not, also choose to reduce its own generation as part of its approach for meeting the standard of performance assigned to it by its state. Through the coordinated operation of the integrated electricity system, subject to the collective requirements that will be imposed on affected EGUs in order to meet the

[421] For purposes of this rulemaking, ''existing'' EGUs include units under construction as of January 8, 2014, the date of publication in the **Federal Register** of the proposed carbon pollution standards for new fossil fuel-fired EGUs.

emissions standards representing the BSER, an increase in RE generation will be offset elsewhere in the interconnection by a decrease in other generation. Because of the need to meet the collective requirements, the decrease in generation resulting from that coordinated operation is most likely to be generation from an affected EGU. Measures taken by affected EGUs that result in emission reductions from other sources in the source category may appropriately be deemed methods to implement the ''system of emission reduction.''

The renewable capacity measures in building block 3 generally perform well against other BSER criteria. Generation from wind turbines and solar voltaic installations, two common renewable technologies, does not produce solid waste or require cooling water, a better environmental outcome than if that amount of generation had instead been produced at a typical range of fossil fuel-fired EGUs. With respect to energy impacts, fossil fuel consumption will decrease both for the source category as a whole and for individual affected EGUs. Although the variable nature of generation from renewable resources such as wind and solar units requires special consideration from grid operators to address possible changes in operating reserve requirements, renewable generation has grown quickly in recent years, as discussed above, and grid planners and operators have proven capable of addressing any consequent changes in requirements through ordinary processes. The EPA believes that planners and operators will be similarly capable of addressing any changes in requirements due to future growth in renewable generation through ordinary processes, but notes that in addition, the reliability safety valve in this rule, discussed in section VIII.G.2, will ensure the absence of adverse energy impacts. With respect to technological innovation, which we consider for the BSER only in the alternative, incentives for expansion of renewable capacity encourage technological innovation in improved renewable technologies as well as more extensive deployment of current advanced technologies. For all these reasons, the measures in building block 3 qualify as a component of the ''best system of emission reduction . . . adequately demonstrated.''

d. *Combination of all three building blocks.* The final BSER includes a combination of all three building blocks. For the reasons described below, and similar to each of the building blocks, the combination must be considered a ''system of emission reduction.'' Moreover, as also discussed below, the combination qualifies as the ''best'' system that is ''adequately demonstrated.'' The combination is technically feasible; it is capable of achieving meaningful reductions in CO_2 emissions from affected EGUs at a reasonable cost; it also performs well against the other BSER factors; and its components are well-established. The combination of the three building blocks will achieve greater CO_2 emission reductions at reasonable costs than possible combinations with fewer building blocks and will also perform better against other BSER factors. We therefore find the combination of all three building blocks to be the ''best system of emission reduction . . . adequately demonstrated'' for reducing CO_2 emissions at affected EGUs.

As already discussed, each of the individual building blocks generally performs well with respect to the BSER factors identified by the statute and the D.C. Circuit. (The exception, which we have pointed out above, is that building block 1, if implemented in isolation, would achieve an insufficient magnitude of emission reductions to be considered the BSER.) The EPA expects that combinations of the building blocks would perform better than the individual building blocks. Beginning with the most obvious and important advantage, combinations of the building blocks will achieve greater emission reductions than the individual building blocks would in isolation, assuming that the building blocks are applied with the same stringency. Because fossil fuel-fired EGUs generally have higher variable costs than other EGUs, it will generally be fossil fuel-fired generation that is replaced when low-variable cost RE generation is increased. At the levels of stringency determined to be reasonable in this rule, opportunities to deploy building block 2 to replace higher-emitting generation and to deploy building block 3 to replace any emitting generation are not exhausted. Thus, as the system of emission reduction is expanded to include each of these building blocks, the emission reductions that will be achieved increase.

Because the stringency and timing of emission reductions achievable through use of each individual building block have been set based on what is achievable at reasonable cost rather than the maximum achievable amount, the stringency of the combination of building blocks is also reasonable, and the combination provides headroom and additional flexibility for states in setting standards of performance and for sources in complying with those standards to choose among multiple means of reducing emissions.

With respect to the quantity of emission reductions expected to be achieved from building block 1 in particular, the BSER encompassing all three building blocks is a substantial improvement over building block 1 in isolation. As noted earlier, the EPA is concerned that implementation of building block 1 in isolation not only would achieve insufficient emission reductions assuming generation levels from affected steam EGUs were held constant, but also has the potential to result in a ''rebound effect.'' The nature of the potential rebound effect is that by causing affected steam EGUs to improve their heat rates and thereby lower their variable operating costs, building block 1 if implemented in isolation would make those EGUs more competitive relative to other, lower-emitting fossil fuel-fired EGUs, possibly resulting in increased generation and higher emissions from the affected steam EGUs in spite of their lower emission rates. Combining building block 1 with the other building blocks addresses this concern by ensuring that owner/operators of affected steam EGUs as a group would have appropriate incentives not only to improve the steam EGUs' efficiency but also to reduce generation from those EGUs consistent with replacement of generation by low- or zero-emitting EGUs. While combining building block 1 with either building block 2 or 3 should address this concern, the combination of all three building blocks addresses it more effectively by strengthening the incentives to reduce generation from affected steam EGUs.

The combination of all three building blocks is also of reasonable cost, for a number of independent reasons described below. The emission reductions associated with the BSER determined in this rule are significant, necessary, and achievable. As discussed in section V.A.1. above, the Administrator must take cost into account when determining that the measures constituting the BSER are adequately demonstrated, and the Administrator has done so here. Below, we summarize information on the cost of the building block measures and discuss the several independent reasons for the Administrator's determination that the costs of the building block 1, 2, and 3 measures, alone or in combination, are reasonable. In considering whether these costs are reasonable, the EPA considered the costs in light of both the observed and projected effects of GHGs in the atmosphere, their effect on climate, and the public health and welfare risks and impacts associated with such climate change, as described in Section II.A. The EPA focused on public health and welfare impacts within the U.S., but the impacts in other world regions strengthen the case for action because impacts in other world regions can in turn adversely affect the U.S. or its citizens. In looking at whether costs were reasonable, the EPA also considered that EGUs are by far the largest emitters of GHGs among stationary sources in the U.S., as more fully set forth in section II.B.

As described in sections V.C. through V.E. and the GHG Mitigation Measures TSD, the EPA has determined that the cost of each of the three building blocks is reasonable. In summary, these cost estimates are $23 per ton of CO_2 reductions for building block 1, $24 per ton for building block 2, and $37 per ton for building block 3. The EPA estimates that, together, the three building blocks are able to achieve CO_2 reductions at an average cost of $30 per ton, which the EPA likewise has determined is reasonable. The $30 per ton estimate is an average of the estimates for each building block, weighted by the total estimated cumulative CO_2 reductions for each of these building blocks over the 2022–2030 period. While it is possible to weight each building block by other amounts, the EPA believes that weighting by cumulative CO_2 reductions best reflects the average cost of total reduction potential across the three building blocks. The EPA considers each of these cost levels reasonable for purposes of the BSER established for this rule.

The EPA views the weighted average cost estimate as a conservatively high estimate of the cost of deploying all three building blocks simultaneously. The simultaneous application of all three building blocks produces interactive dynamics, some of which could increase the cost and some of which could decrease the cost represented in the individual building blocks. For example, one dynamic that would tend to raise costs (and whose omission would therefore make the weighted average understate costs) is that the emission reduction measures associated with building blocks 2 and 3 both prioritize the replacement of higher-cost generation (from affected steam EGUs in the case of building block 2 and from all affected EGUs in the case of building block 3). The EPA recognizes that the increased magnitude of generation replacement when building blocks 2 and 3 are implemented together necessitates that some of the generation replacement will occur at more efficient affected EGUs, at a relatively higher cost; however, this is a consequence of the greater emission reductions that can be achieved by combining building blocks, not an indication that any individual building block has become more expensive because of the combined deployment.

Also, the EPA recognizes that when building block 1 is combined with the other building blocks, the combination has the potential to raise the cost of the portion of the overall emission reductions achievable through heat rate improvements relative to the cost of those same reductions if building block 1 were implemented in isolation (assuming for purposes of this discussion that the rebound effect is not an issue and that the affected steam EGUs would in fact reduce their emissions if building block 1 were implemented in isolation).[422] However, we believe that the cost of emission reductions achieved through heat rate improvements in the context of a three-building block BSER will remain reasonable for two reasons. First, as discussed in section V.C. below, even when conservatively high investment costs are assumed, the cost of CO_2 emission reductions achievable through heat rate improvements is low enough that the cost per ton of CO_2 emission reductions will remain reasonable even if that cost is substantially increased. Second, although under a BSER encompassing all three building blocks the volume of coal-fired generation will decrease, that decrease is unlikely to be spread uniformly among all coal-fired EGUs. It is more likely that some coal-fired EGUs will decrease their generation slightly or not at all while others will decrease their generation by larger percentages or cease operations altogether. We would expect EGU owners to take these changes in EGU operating patterns into account when considering where to invest in heat rate improvements, with the result that there will be a tendency for such investments to be concentrated in EGUs whose generation output is expected to decrease the least. This enlightened bias in spending on heat rate improvements—that is, focusing investments on EGUs where such improvements will have the largest impacts and produce the highest returns, given consideration of projected changes in dispatch patterns—will tend to mitigate any deterioration in the cost of CO_2 emission reductions achievable through heat rate improvements.

In contrast with those prior examples, combining the building blocks also produces interactive dynamics that significantly reduce the cost for CO_2 reductions represented in the individual building blocks (and whose omission would therefore make the weighted average overstate costs). Foremost among these dynamics is the stabilization of wholesale power prices. When assessed individually, building blocks 2 and 3 have opposite impacts on wholesale power prices, although in each case, the direction of the wholesale power price impact corresponds to an increasing cost of that building block in isolation. For example, building block 2 promotes more utilization of existing NGCC capacity, which (assessed on its own) would increase natural gas consumption and therefore price, in turn raising wholesale power prices (which are often determined by gas-fired generators as the power supplier on the margin); this dynamic puts upward pressure on the cost of achieving CO_2 reductions through shifting generation from steam EGUs to NGCC units.[423] Meanwhile, building block 3 increases RE deployment; because RE generators have very little variable cost, an increase in RE generation replaces other supply with higher variable cost, which would yield lower wholesale power prices. Lower wholesale power prices would make further RE deployment less competitive against generation from existing emitting sources; while this dynamic would generally reduce electricity prices to consumers, it also puts upward pressure on the cost of achieving CO_2 reductions through increased RE deployment.[424] Applying building blocks 2 and 3 together produces significantly more CO_2 reductions at a relatively lower cost because the countervailing nature of these wholesale power price dynamics mitigates the primary cost drivers for each building block.[425]

[422] If an EGU produces less generation output, then an improvement in that EGU's heat rate and rate of CO_2 emissions per unit of generation produces a smaller reduction in CO_2 emissions. If the investment required to achieve the improvement in heat rate and emission rate is the same regardless of the EGU's generation output, then the cost per unit of CO_2 emission reduction will be higher when the EGU's generation output is lower. Commenters have also stated that operating at lower capacity factors may cause units to experience deterioration in heat rates.

[423] The EPA's cost-effectiveness estimate of $24 per ton for building block 2 reflects these market dynamics.

[424] The EPA's cost-effectiveness estimate of $37 per ton for building block 3 reflects these market dynamics.

[425] Notwithstanding the interactive dynamics that improve the cost effectiveness of emission reductions when building blocks 2 and 3 are implemented together, we also consider each of these building blocks to be independently of reasonable cost, so that either building block 2 or

Continued

The EPA believes the dynamics tending to cause the weighted average above to overstate costs of the combination of building blocks are greater than the dynamics tending to cause costs to be understated, and that the weighted average costs are therefore conservatively high. Analysis performed by the EPA at an earlier stage of the rulemaking supports this conclusion. At proposal, the EPA evaluated the cost of increasing NGCC utilization (building block 2) and deploying incremental RE generation (building block 3) independently, as well as the cost of simultaneously increasing NGCC utilization and incremental RE generation. The average cost (in dollars per ton of CO_2 reduced) was less for the combined building block scenario, showing that the net outcome of the interactivity effects described above is a reduction in cost per ton when compared to cost estimates that do not incorporate this interactivity.[426]

A final reason why the EPA considers the weighted-average cost above conservatively high is that simply combining the building blocks at their full individual stringencies overstates the stringency of the BSER. As discussed in section V.A.3.f and section VI, the BSER reflects the combined degree of emission limitation achieved through application of the building blocks in the least stringent region. By definition, in the other two regions, the BSER is less stringent than the simple combination of the three building blocks whose stringency is represented in the weighted-average cost above.

The cost estimates for each of the three building blocks cited above—$23, $24, and $37 per ton of CO_2 reductions from building blocks 1, 2, and 3, respectively—are each conservatively high for the reasons discussed in section V.C., V.D., and V.E. below. Likewise, the $30 per ton weighted-average cost of all three building blocks is a conservatively high estimate of the cost of the combination of the three individual building block costs, as described above. While conservatively high, and especially so in the case of the $30 per ton weighted-average cost, these estimates fall well within the range of costs that are reasonable for the BSER for this rule.

In assessing cost reasonableness for the BSER determination for this rule, the EPA has compared the estimated costs discussed above to two types of cost benchmark. The first type of benchmark comprises costs that affected EGUs incur to reduce other air pollutants, such as SO_2 and NO_X. In order to address various environmental requirements, many coal-fired EGUs have been required to decide between either shutting down or installing and operating flue gas desulfurization (FGD) equipment—that is, wet or dry scrubbers—to reduce their SO_2 emissions. The fact that many of these EGUs have chosen scrubbers in preference to shutting down is evidence that scrubber costs are reasonable, and we believe that the cost of these controls can reasonably serve as a cost benchmark for comparison to the costs of this rule. We estimate that for a 300–700 MW coal-fired steam EGU with a heat rate of 10,000 Btu per kWh and operating at a 70 percent utilization rate, the annualized costs of installing and operating a wet scrubber are approximately $14 to $18 per MWh and the annualized costs of installing and operating a dry scrubber are approximately $13 to $16 per MWh.[427]

In comparison, we estimate that for a coal-fired steam EGU with a heat rate of 10,000 Btu per kWh, assuming the conservatively high cost of $30 per ton of CO_2 removed through the combination of all three building blocks, the cost of reducing CO_2 emissions by the amount required to achieve the uniform CO_2 emission performance rate for steam EGUs of 1,305 lbs. CO_2 per MWh would be equivalent to approximately $11 per MWh. The comparable costs for achieving the required emission performance rate for steam EGUs through use of the individual building blocks range from $8 to $14 per MWh. For an NGCC unit with a heat rate of 7,800 Btu per kWh, assuming a conservatively high cost of $37 per ton of CO_2 removed through the use of building block 3,[428] the cost of reducing CO_2 emissions by the amount required to achieve the uniform CO_2 emission performance rate for NGCC units of 771 lbs. CO_2 per MWh would be equivalent to approximately $3 per MWh.[429] These estimated CO_2 reduction costs of $3 to $14 per MWh to achieve the CO_2 emission performance rates are either less than the ranges of $14 to $18 and $13 to $16 per MWh to install and operate a wet or dry scrubber, or in the case of CO_2 emission reductions at a steam unit achieved through building block 3, near the low end of the ranges of scrubber costs. This comparison demonstrates that the costs associated with the BSER in this rule are reasonable compared to the costs that affected EGUs commonly face to comply with other environmental requirements.

The second type of benchmark comprises CO_2 prices that owners of affected EGUs use for planning purposes in their IRPs. Utilities subject to requirements to prepare IRPs commonly include assumptions regarding future environmental regulations that may become effective during the time horizon covered by the IRP, and assumptions regarding CO_2 regulations are often represented in the form of assumed prices per ton of CO_2 emitted or reduced. A survey of the CO_2 price assumptions from 46 recent IRPs shows a range of CO_2 prices in the IRPs' reference cases of $0 to $30 per ton, and a range of CO_2 prices in the IRPs' high cases from $0 to $110 per ton.[430] In comparison, the conservatively high, weighted-average cost of $30 per ton removed described above is at the high end of the range of reference case assumptions but at the low end of the range of the high case assumptions. The costs of the individual building blocks are likewise well within the range of the high case assumptions, and either at or slightly above the high end of the reference case assumptions. This comparison demonstrates that the costs associated with the BSER in this rule are reasonable compared to the expectations of the industry for the potential costs of CO_2 regulation.

In addition to comparison to these benchmarks, there is a third independent way in which EPA has considered cost. In light of the severity of the observed and projected climate change effects on the U.S., U.S. interests, and U.S. citizens, combined with EGUs' large contribution to U.S. GHG emissions, the costs of the BSER measures are reasonable when compared to other potential control measures for this sector available under

3 alone, or combinations of the building blocks that include either but not both of these two building blocks, could be the BSER if a court were to strike down the other building block, as discussed in section V.A.7. below. (We also note in section V.A.7. that a combination of building blocks 2 and 3 without building block 1 could be the BSER if a court were to strike down building block 1.)

[426] Specifically, at proposal the EPA quantified the average cost, in dollar per ton of CO_2 reduced, of building blocks 1, 2, and 3 ($22.5 per ton) to be less than the cost of either building block 2 ($28.9 per ton) or building block 3 ($23.4 per ton) alone.

[427] For details of these computations, see the memorandum ''Comparison of building block costs to FGD costs'' available in the docket.

[428] The comparison for an NGCC unit considers only building block 3 because building blocks 1 and 2 do not apply to NGCC units.

[429] For details of these computations, see the memorandum ''Comparison of building block costs to FGD costs'' available in the docket.

[430] *See* Synapse Energy Economics Inc., 2015 Carbon Dioxide Price Forecast (March 3, 2015) at 25–28, *available at http://www.synapse-energy.com/sites/default/files/2015%20Carbon%20Dioxide%20Price%20Report.pdf.*

section 111. Given EGUs' large contribution to U.S. GHG emissions, any attempt to address the serious public health and environmental threat of climate change must necessarily include significant emission reductions from this sector. The agency would therefore consider even relatively high costs—which these are not—to be reasonable. Imposing only the lower cost reduction measures in building block 1 would not achieve sufficient reductions given the scope of the problem and EGUs' contribution to it. While the EPA also considered measures such as CCS retrofits for all fossil-fired EGUs or co-firing at all steam units, the EPA determined that these costs were too high when considered on a sector-wide basis. Furthermore, the EPA has not identified other measures available under section 111 that are less costly and would achieve emission reductions that are commensurate with the scope of the problem and EGUs' contribution to it. Thus, the EPA determined that the costs of the measures in building blocks 1, 2 and 3, individually or in combination, are reasonable because they achieve an appropriate balance between cost and amount of reductions given the other potential control measures under section 111.

As required under Executive Order 12866, the EPA conducts benefit-cost analyses for major Clean Air Act rules.[431] While benefit-cost analysis can help to inform policy decisions, as permissible and appropriate under governing statutory provisions, the EPA does not use a benefit-cost test (*i.e.,* a determination of whether monetized benefits exceed costs) as the sole or primary decision tool when required to consider costs or to determine whether to issue regulations under the Clean Air Act, and is not using such a test here.[432] Nonetheless, the EPA observes that the costs of the building block 1, 2 and 3 measures, both individually and combined as discussed in this section above, are less than the central estimates of the social cost of carbon. Developed by an interagency workgroup, the social cost of carbon (SC–CO_2) is an estimate of the monetary value of impacts associated with marginal changes in CO_2 emissions in a given year.[433] It is typically used to assess the avoided damages as a result of regulatory actions (*i.e.,* benefits of rulemakings that lead to an incremental reduction in cumulative global CO_2 emissions).[434] The central values for the SC–CO_2 range from $40 per short ton in 2020 to $48 per short ton in 2030.[435] The weighted-average cost estimate of $30 per ton is well below this range.

Finally, the EPA notes that the combination of all three building blocks would perform consistently with the individual building blocks with respect to non-air energy and environmental impacts. There is no reason to expect an adverse non-air environmental or energy impact from deployment of the combination of the three building blocks, whether considered on a source-by-source basis, on a sector-wide or national basis, or both. In fact, the combination of the building blocks, like the building blocks individually, as discussed above, would be expected to produce non-air environmental co-benefits in the form of reduced water usage and solid waste production (and, in addition to these non-air environmental co-benefits, would also be expected to reduce emissions of non-CO_2 air pollutants such as SO_2, NO_X, and mercury). Likewise, with respect to technological innovation, which we consider only in the alternative, the building blocks in combination would have the same positive effects that they would have if implemented independently.

e. *Other combinations of the building blocks.* The EPA has considered whether other combinations of the building blocks, such as a combination of building blocks 1 and 2 or a combination of building blocks 1 and 3, could be the BSER. We believe that any such combination is technically feasible and would be a ''system of emission reduction'' capable of achieving meaningful reductions in CO_2 emissions from affected EGUs at a reasonable cost. As with the combination of three building blocks discussed above, any combination of building blocks would achieve greater emission reductions than the individual building blocks encompassed in that combination would achieve if implemented in isolation. Further, the cost of any combination would be driven principally by the combined stringency and would remain reasonable in aggregate, such that the conclusions on cost reasonableness discussed in section V.A.4.d. would continue to apply. We have already noted our determination that building block 1 in isolation is not the BSER because it would not produce a sufficient quantity of emission reductions. A combination of building block 1 with one of the other building blocks would produce greater emission reductions and would not be subject to this concern. Any combination of building blocks including building block 1 and at least one other building block would also address the concern about potential ''rebound effect,'' discussed above, that could occur if building block 1 were implemented in isolation. Finally, there is no reason to expect any combination of the building blocks to have adverse non-air energy or environmental impacts, and the implications for technological innovation, which we consider only in the alternative, would likewise be positive for any combination of the building blocks because those implications are positive for the individual building blocks and there is no reason to expect negative interaction from a combination of building blocks.

For these reasons, any combination of the building blocks (but not a BSER comprising building block 1 in isolation) could be the BSER if it were not for the fact that a BSER comprising all three of the building blocks will achieve greater emission reductions at a reasonable cost and is therefore ''better.'' As discussed below in section V.A.7., we intend for the individual building blocks to be severable, such that if a court were to deem building block 2 or 3 defective, but not both, the BSER would comprise the remaining building blocks.

f. *Achievability of emission limits.* As noted, based on the BSER, the EPA has

[431] The EPA's regulatory impact analysis for this rule, which appropriately includes a representation of the flexibility available under the rule to comply using a combination of BSER and non-BSER measures (such as demand-side energy efficiency) is discussed in section XI of the preamble.

[432] See memo entitled ''Consideration of Costs and Benefits Under the Clean Air Act'' available in the docket.

[433] Estimates are presented in the *Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866 (May 2013, Revised July 2015),* Interagency Working Group on Social Cost of Carbon, with participation by Council of Economic Advisers, Council on Environmental Quality, Department of Agriculture, Department of Commerce, Department of Energy, Department of Transportation, Environmental Protection Agency, National Economic Council, Office of Energy and Climate Change, Office of Management and Budget, Office of Science and Technology Policy, and Department of Treasury (May 2013, Revised July 2015). Available at: *https://www.whitehouse.gov/sites/default/files/omb/inforeg/scc-tsd-final-july-2015.pdf*> Accessed 7/11/2015.

[434] The SC–CO_2 estimates do not include all important damages because of current modeling and data limitations. The 2014 IPCC report observed that SC–CO_2 estimates omit various impacts that would likely increase damages. *See* IPCC, 2014: *Climate Change 2014: Impacts, Adaptation, and Vulnerability.* Contribution of Working Group II to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change. Cambridge University Press, Cambridge. *https://www.ipcc.ch/report/ar5/wg2/.*

[435] The 2010 and 2013 TSDs present SC–CO_2 in 2007$ per metric ton. The unrounded estimates from the current TSD were adjusted to (1) 2011$ using GDP Implicit Price Deflator (1.061374), *http://www.bea.gov/iTable/index_nipa.cfm* and (2) short tons using the conversion factor of 0.90718474 metric tons in a short ton. These estimates were rounded to two significant digits.

established a source subcategory-specific emission performance rate for fossil steam units and one for NGCC units. As discussed in section V.A.1.c., for new sources, standards of performance must be ''achievable'' under CAA section 111(a)(1), and the D.C. Circuit has identified criteria for achievability.[436] In this rule, the EPA is taking the approach that while the states are not required to adopt those source subcategory-specific emission performance rates as the standards of performance for their affected EGUs, those rates must be achievable by the steam generator and NGCC subcategories, respectively. In addition, the EPA is assuming that the achievability criteria in the case law for new sources apply to existing sources under section 111(d). For the reasons discussed next, for this rule, the source subcategory-specific emission performance rates are achievable in accordance with those criteria in the case law.

As noted, the building blocks include several features that assure that affected EGUs may implement them. The building blocks may be implemented through a range of methods, including through the purchase of ERCs and emission trading. In addition, the building blocks incorporate ''headroom.'' Moreover, the source subcategory-specific emission performance rates apply on an annual or longer basis, so that short-term issues need not jeopardize compliance. In addition, we quantify the emission performance rates based on the degree of emission limitation achievable by affected EGUs in the region where application of the combined building blocks results in the least stringent emission rate. Because the means to implement the building blocks are widely available and because of the just-noted flexibilities and approaches to the emission performance rates, all types of affected steam generating units, operating throughout the lower-48 states and under all types of regulatory regimes, are able to implement building blocks 1, 2 and 3 and thereby achieve the emission performance rate for fossil steam units, and all types of NGCC units operating in all states under all types of regulatory requirements are able to implement building block 3 and thereby achieve the emission performance rate for NGCC units.[437]

Commenters have raised questions about whether particular circumstances could arise, such as the sudden loss of certain generation assets, that would cause the implementation of the building blocks to cause reliability problems, and have cautioned that these circumstances could preclude implementation of the building blocks and thus achievement of the emission performance rates. Commenters have also raised concerns about whether affected EGUs with limited remaining useful lives can implement the building blocks and achieve the emission performance rates. We address those concerns in section VIII, where we authorize state plans to include a reliability mechanism and discuss affected EGUs with limited remaining useful lives. Accordingly, we conclude that the source subcategory-specific emission performance standards are achievable in accordance with the case law.

5. Actions Under the BSER That Sources Can Take To Achieve Standards of Performance

Based on the determination of the BSER described above, the EPA has identified a performance rate of 1305 lbs. per net MWh for affected steam EGUs and a performance rate of 771 lbs. per net MWh for affected stationary combustion turbines. The computations of these performance rates and the determinations of state goals reflecting these rates are described in sections VI and VII of the preamble, respectively.

Under section 111(d), states determine the standards of performance for individual sources. The EPA is authorizing states to express the standards of performance applicable to affected EGUs as either emission rate-based limits or mass-based limits. As described above, the sets of actions that sources can take to comply with these standards implement or apply the BSER and, in that sense, may be understood as part of the BSER.

A source to which a state applies an emission rate-based limit can achieve the limit through a combination of the following set of measures (to the extent allowed by the state plan), all of which are components of the BSER, again, in the sense that they implement or apply it:

- Reducing its heat rate (building block 1).
- Directly investing in, or purchasing ERCs created as a result of, incremental generation from existing NGCC units (building block 2).
- Directly investing in, or purchasing ERCs created as a result of, generation from new or uprated RE generators (building block 3).
- Reducing its utilization, coupled with direct investment in or purchase of ERCs representing building blocks 2 and 3 as indicated above.
- Investing in surplus emission rate reductions at other affected EGUs through the purchase or other acquisition of rate-based emission credits.

A source to which a state applies a mass-based limit can achieve the limit through a combination of the following set of measures (to the extent allowed by the state plan), all of which are likewise components of the BSER:

- Reducing its heat rate (building block 1).
- Reducing its utilization and allowing its generation to be replaced or avoided through the routine operation of industry reliability planning mechanisms and market incentives.
- Investing in surplus emission reductions at other affected EGUs through the purchase or other acquisition of mass-based emission allowances.

The EPA has determined appropriate CO_2 emission performance rates for each of the two source subcategories as a whole achievable through application of the building blocks. The wide ranges of measures included in the BSER and available to individual sources as indicated above provide assurance that the source category as a whole can achieve standards of performance consistent with those emissions standards using components of the BSER, whether states choose to establish emission rate-based limits or mass-based limits. The wide ranges of measures included in the BSER also provide assurance that each individual affected EGU could achieve the standard of performance its state establishes for it using components of the BSER. Of course, sources may also employ measures not included in the BSER, to the extent allowed under the applicable state plan.

In the remainder of this subsection, we discuss further how affected EGUs can use each of the measures listed above to achieve emission rate-based forms of performance standards and mass-based forms of performance standards, indicating that all types of owner/operators of affected EGUs—*i.e.,* vertically integrated utilities and merchant generators; investor-owned, government-owned, and customer-owned (cooperative) utilities; and owner/operators of large, small, and single-unit fleets of generating units—have the ability to implement each of the building blocks in some way. In the following subsection we discuss the use

[436] *See Essex Chem. Corp.* v. *Ruckelshaus,* 486 F.2d 427, 433–34 (D.C. Cir. 1973), *cert. denied,* 416 U.S. 969 (1974); *Nat'l Lime Ass'n* v. *EPA,* 627 F.2d 416, 433, n.46 (D.C. Cir. 1980); *Sierra Club* v. *Costle,* 657 F.2d 298, 377 (D.C. Cir. 1981) (citing *Nat'l Lime Ass'n* v. *EPA,* 627 F.2d 416 (D.C. Cir. 1980).

[437] We discuss the ability of affected EGUs to implement the building blocks in more detail in sections V.C., V.D., and V.E. and the accompanying support documents.

of measures not in the BSER that can help sources achieve the standards of performance.

a. *Use of BSER measures to achieve an emission rate-based standard.* Under an emission-rate based form of performance standards, compliance is nominally determined through a comparison of the affected EGU's emission rate to the emission rate standard. The emissions-reducing impact of BSER measures that reduce CO_2 emissions through reductions in the quantity of generation rather than through reductions in the amount of CO_2 emitted per unit of generation would not be reflected in an affected EGU's emission rate computed solely based on measured stack emissions and measured electricity generation but can readily be reflected in an emission rate computation by averaging ERCs acquired by the affected EGU into the rate computation.

In section VIII.K, we discuss the processes for issuance and use of ERCs that can be included in the emission rate computations that affected EGUs perform to demonstrate compliance with an emission rate standard. This ERC mechanism is analogous to the approach the EPA has used to reflect building blocks 2 and 3 in the uniform emission rates representing the BSER, as discussed in section VI below. As summarized below and as discussed in greater detail in section VIII.K, the existence of a clearly feasible path for usage of ERCs ensures that emission reductions achievable through implementation of the measures in building blocks 2 and 3 are available to assist all affected EGUs in achieving compliance with standards of performance based on the BSER.

(1) *Building block 1.*

The owner/operator of an affected steam EGU can take steps to reduce the unit's heat rate, thereby lowering the unit's CO_2 emission rate. Examples of actions in this category are included in section V.C. below and in the GHG Mitigation Measures TSD for the CPP Final Rule. Any type of owner/operator can take advantage of this measure.

(2) *Building block 2.*

The owner/operator of an affected EGU can average the EGU's emission rate with ERCs issued on the basis of incremental generation from an existing NGCC unit. As permitted under the EGU's state's section 111(d) plan, the owner/operator of the affected EGU could accomplish this through either common ownership of the NGCC unit, a bilateral transaction with the owner/operator of the NGCC unit, or a transaction for ERCs through an intermediary, which could but need not involve an organized market.[438] As discussed earlier, based on observation of market behavior both inside and outside the electricity industry, we expect that intermediaries will seek opportunities to participate in such transactions and that organized markets are likely to develop as well if section 111(d) plans authorize the use of ERCs. While the opportunity to acquire ERCs through common ownership of NGCC facilities might not extend to owner/operators of single EGUs or small fleets, all owner/operators would have the ability to engage in bilateral or intermediated purchase transactions for ERCs just as they can engage in transactions for other kinds of goods and services.

In section VIII.K below, the EPA sets out the minimum criteria that must be satisfied for generation and issuance of a valid ERC based upon incremental electricity generation by an existing NGCC unit. Those criteria generally concern ensuring that the physical basis for the ERC—*i.e.,* qualifying generation by an existing NGCC unit and the NGCC unit CO_2 emissions associated with that qualifying generation—is adequately monitored and that there is an adequate administrative process for tracking credits to avoid double-counting. In the case of ERCs related to building block 2, the monitoring criteria would generally be satisfied by standard 40 CFR part 75 monitoring.

The owner/operator of an affected steam EGU would use the ERCs it has acquired for compliance—whether acquired through ownership of NGCC capacity, a bilateral transaction, or an intermediated transaction—by adding the ERCs to its measured net generation when computing its CO_2 emission rate for purposes of demonstrating compliance with its emission rate-based standard of performance.

(3) *Building block 3.*

The owner/operator of an affected EGU can average the EGU's emission rate with ERCs issued on the basis of generation from new (*i.e.,* post-2012) RE generating capacity, including both newly constructed capacity and new uprates to existing RE generating capacity. As permitted under the EGU's state's section 111(d) plan, the owner/operator of the affected EGU could accomplish this through either common ownership of the RE generating capacity, a bilateral transaction with the owner/operator of the RE generating capacity, or a transaction for ERCs through an intermediary, which could, but need not, involve an organized market.[439] As discussed earlier, based on observation of market behavior both inside and outside the electricity industry, we expect that intermediaries will seek opportunities to participate in such transactions and that organized markets are likely to develop as well if section 111(d) plans authorize the use of ERCs. While the opportunity to acquire ERCs through common ownership of RE generating facilities might not extend to owner/operators of single EGUs or small fleets, all owner/operators would have the ability to engage in bilateral or intermediated purchase transactions for ERCs just as they can engage in transactions for other kinds of goods and services.

In section VIII.K below, the EPA sets out the minimum criteria that must be satisfied for generation and issuance of a valid ERC based upon generation from new RE generating capacity. Those criteria generally concern assuring that the physical basis for the ERC—*i.e.,* generation by qualifying new RE capacity—is adequately monitored and that there is an adequate administrative process for tracking credits to avoid double-counting.[440]

As with building block 2, the owner/operator of an affected EGU would use the ERCs it has acquired for compliance—whether acquired through ownership of qualifying RE generating capacity, a bilateral transaction, or an intermediated transaction—by adding the ERCs to its measured net generation when computing its CO_2 emission rate for purposes of demonstrating compliance with its emission rate-based standard of performance.

(4) *Reduced generation.*

The owner/operator of an affected EGU can reduce the unit's generation and reflect that reduction in the form of a lower emission rate provided that the owner/operator also acquires some amount of ERCs to use in computing the unit's emission rate for purposes of demonstrating compliance. As

---

[438] Each of these methods of implementing building block 2 meets the criteria for the BSER in that (i) as we discuss in section V.D. and supporting documents, each of these methods is adequately demonstrated;(ii) the costs of each of these methods on a source-by-source basis are reasonable, as discussed above; and (iii) none of these methods causes adverse energy impacts or non-quality environmental impacts.

[439] As with building block 2, each of these methods of implementing building block 3 meets the criteria for the BSER in that (i) as we discuss in section V.E. and supporting documents, each of these methods is adequately demonstrated; (ii) the costs of each of these methods on a source-by-source basis are reasonable, as discussed above; and (iii) none of these methods causes adverse energy impacts or non-quality environmental impacts.

[440] The possible use of types of RE generating capacity that are not included in the BSER is discussed in section V.A.6. and section VIII of the preamble.

permitted under the EGU's state's section 111(d) plan, the ERCs could be acquired through investment in incremental generation from existing NGCC capacity, generation from new RE generating capacity, or purchase from an entity with surplus ERCs. If the owner/operator does not average any ERCs into the unit's emission rate, reducing the unit's own generation will proportionately reduce both the numerator and denominator of the fraction and therefore will not affect the computed emission rate (unless the unit retires, reducing its emission rate to zero). However, if the owner/operator does average ERCs into the unit's emission rate, then a proportional reduction in both the numerator and the portion of the denominator representing the unit's measured generation will amplify the effect of the acquired ERCs in the computation, with the result that the more the unit reduces its generation, the fewer ERCs will be needed to reach a given emission rate-based standard of performance. All owner/operators have the ability to reduce generation, and as discussed above all also would be capable of acquiring ERCs, so all would be capable of reflecting reduced utilization in their emission rates for purposes of demonstrating compliance.

(5) *Emissions trading approaches.*

To the extent allowed under standards of performance that incorporate emissions trading or otherwise through the relevant section 111(d) plans, the owner/operator of an affected EGU can acquire tradable rate-based emission credits representing an investment in surplus emission rate reductions not needed by another affected EGU and can average those credits into its own emission rate for purposes of demonstrating compliance with its rate-based standard of performance. The approach would have to be authorized in the appropriate section 111(d) plan and would have to conform to the minimum conditions for such approaches described in section VIII below. As we have repeatedly noted, based on our reading of the comment record and the discussions that occurred during the outreach process, it is reasonable to presume that such authorization will be forthcoming from states that submit plans establishing rate-based standards of performance for their affected EGUs.

Under a rate-based emissions trading approach, credits are initially created and issued according to processes defined in the state plan. After credits are initially issued, the owner/operator of an affected EGU needing additional credits can acquire credits through common ownership of another affected EGU or through a bilateral transaction with the other affected EGU, or the owner/operator of the affected EGU can acquire credits in a transaction through an intermediary, which could, but need not, involve an organized market. As discussed earlier, based on observation of market behavior both inside and outside the electricity industry, we expect that intermediaries will seek opportunities to participate in such transactions and that organized markets are likely to develop as well if section 111(d) plans and/or standards of performance established thereunder authorize emissions trading. While the opportunity to acquire credits through common ownership might not extend to owner/operators of single EGUs or small fleets, all owner/operators would have the ability to engage in bilateral or intermediated purchase transactions for credits just as they can engage in transactions for other kinds of goods and services.

Further details regarding the possible use of rate-based emission credits in a state plan (using ERCs issued on the basis of investments in building blocks 2 and 3 and potentially other measures as the credits) are provided in section VIII.K.

b. *Use of BSER measures to achieve a mass-based standard.* Under a mass-based form of the standard, compliance is determined through a comparison of the affected EGU's monitored mass emissions to a mass-based emission limit. Although a state could choose to impose specific mass-based limits that each EGU would be required to meet on a physical basis, in past instances where mass-based limits have been established for large numbers of sources it has been typical for the limit on each affected EGU to be structured as a requirement to periodically surrender a quantity of emission allowances equal to the source's monitored mass emissions. The EPA believes that section 111(d) encompasses the flexibility for plans to impose mass-based standards in the typical manner where the standard of performance for each affected EGU consists of a requirement to surrender emission allowances rather than a requirement to physically comply with a unit-specific emissions cap.

Measurements of mass emissions at a given affected EGU capture reductions in the EGU's emissions arising from both reductions in generation and reductions in the emission rate per MWh. Accordingly, under a mass-based standard there is no need to provide a mechanism such as the ERC mechanism described above in order to properly account for emission reductions attributable to particular types of BSER measures. The relative simplicity of the mechanics of monitoring and determining compliance are significant advantages inherent in the use of mass-based standards rather than emission rate-based standards.

(1) *Building block 1.*

The owner/operator of an affected steam EGU can take steps to reduce the unit's heat rate, thereby lowering the unit's CO_2 mass emissions. Examples of actions in this category are included in section V.C. below and in the GHG Mitigation Measures TSD for the CPP Final Rule. Any type of owner/operator can take advantage of this measure.

(2) *Reduced generation.*

The owner/operator of an affected EGU can reduce its generation, thereby lowering the unit's CO_2 mass emissions. Any type of owner/operator can take advantage of this measure. Although some action or combination of actions to increase lower-carbon generation or reduce electricity demand somewhere in the interconnected electricity system of which the affected EGU is a part will be required to enable electricity supply and demand to remain in balance, the affected EGU does not need to monitor or track those actions in order to use its reduction in generation to help achieve compliance with the mass-based standard. Instead, multiple participants in the interconnected electricity system will act to ensure that supply and demand remain in balance, subject to the complex and constantly changing set of constraints on operation of the system, just as those participants have routinely done for years.

Of course, if the owner/operator of the affected EGU wishes to play a direct role in driving the increase in lower-carbon generation or demand-side EE required to offset a reduction in the affected EGU's generation, the owner/operator may do so as part of whatever role it happens to play as a participant in the interconnected electricity system. However, the owner/operator will achieve the benefit that reduction in generation brings toward compliance with the mass-based standard whether it takes those additional actions itself or instead allows other participants in the interconnected electricity system to play that role.

(3) *Emissions trading approaches.*

To the extent allowed under the relevant section 111(d) plans—as the record indicates that it is reasonable to expect it will be—the owner/operator of an affected EGU can acquire tradable mass-based emission allowances representing investment in surplus emission reductions not needed by another affected EGU and can aggregate those allowances with any other allowances it already holds for purposes of demonstrating compliance with its mass-based standard of performance. The approach would have to be authorized in the appropriate section 111(d) plan and would have to conform to the minimum conditions for such approaches described in section VIII below.

Under a mass-based emissions trading approach, the total number of allowances to be issued is defined in the state plan, and affected EGUs may obtain an initial quantity of allowances through an allocation or auction process. After that initial process, the owner/operator of an affected EGU needing additional allowances can acquire allowances through common ownership of another affected EGU or through a bilateral transaction with the other affected EGU, or the owner/operator of the affected EGU can acquire allowances in a transaction through an intermediary, which could but need not involve an organized market. As discussed earlier, based on observation of market behavior both inside and outside the electricity industry, we expect that intermediaries will seek opportunities to participate in such transactions and that organized markets are likely to develop as well if section 111(d) plans authorize the use of emissions trading. While the opportunity to acquire allowances through common ownership might not extend to owner/operators of single EGUs or small fleets, all owner/operators would have the ability to engage in bilateral or intermediated purchase transactions for allowances just as they can engage in transactions for other kinds of goods and services.

Further details regarding the possible use of mass-based emission allowances in a state plan are provided in section VIII.J.

6. Use of Non-BSER Measures To Achieve Standards of Performance

In addition to the BSER-related measures that affected EGUs can use to achieve the standards of performance set in section 111(d) plans, there are a variety of non-BSER measures that could also be employed (to the extent permitted under a given plan). This final rule does not limit the measures that affected EGUs may use for achieving standards of performance to measures that are included in the BSER; thus, the existence of these non-BSER measures provides flexibility allowing the individual affected EGUs and the source category to achieve emission reductions consistent with application of the BSER at the levels of stringency reflected in this final rule even if one or more of the building blocks is not implemented to the degree that the EPA has determined to be reasonable for purposes of quantifying the BSER. In this way, non-BSER measures provide additional flexibility to states in establishing standards of performance for affected EGUs through section 111(d) plans and to individual affected EGUs for achieving those standards.

Any of the non-BSER measures described below would help the affected source category as a whole achieve emission limits consistent with the BSER. The non-BSER measures either reduce the amount of CO_2 emitted per MWh of generation from the set of affected EGUs or reduce the amount of generation, and therefore associated CO_2 emissions, from the set of affected EGUs. However, the manner in which the various non-BSER measures would help individual affected EGUs meet their individual standards of performance varies according to the type of measure and the type of standard of performance—*i.e.,* whether the standard is emission rate-based or mass-based.

In general, a non-BSER measure that reduces the amount of CO_2 emitted per MWh of generation at an affected EGU will reduce the amount of CO_2 emissions monitored at the EGU's stack (assuming the quantity of generation is held constant). Measures of this type can help the EGU meet either an emission rate-based or mass-based standard of performance.

Other non-BSER measures do not reduce an affected EGU's CO_2 emission rate but rather facilitate reductions in CO_2 emissions by reducing the amount of generation from affected EGUs. Under a mass-based standard, the collective reduction in emissions from the set of affected EGUs is reflected in the collective monitored emissions from the set of affected EGUs. An individual EGU that reduces its generation and emissions will be able to use the measure to help achieve its mass-based limit. Individual EGUs that do not reduce their generation and emissions will be able to use the measure, if the relevant section 111(d) plans provide for allowance trading, by purchasing emission allowances no longer needed by EGUs that have reduced their emissions.

Under an emission rate-based standard, non-BSER measures that reduce generation from affected EGUs but do not reduce an affected EGU's emission rate generally can facilitate compliance by serving as the basis for ERCs that affected EGUs can average into their emission rates for purposes of demonstrating compliance. Section VIII.K. includes a discussion of the issuance of ERCs based on various non-BSER measures. Affected EGUs could use such ERCs to the extent permitted by the relevant section 111(d) plans.

The remainder of this section discusses some specific types of non-BSER measures. The first set discussed includes measures that can reduce the amount of CO_2 emitted per MWh of generation, and the second set discussed includes measures that can reduce CO_2 emissions by reducing the amount of generation from affected EGUs. In some cases, considerations related to use of these measures for compliance are discussed below in section VIII on state plans. The EPA notes that this is not an exhaustive list of non-BSER measures that could be employed to reduce CO_2 emissions from affected EGUs, but merely a set of examples that illustrate the extent of the additional flexibility such measures provide to states and affected EGUs under the final rule.

a. *Non-BSER measures that reduce CO_2 emissions per MWh generated.* In the June 2014 proposal, the EPA discussed several potential measures that could reduce CO_2 emissions per MWh generated at affected EGUs but that were not proposed to be part of the BSER. The measures discussed included heat rate improvements at affected EGUs other than coal-fired steam EGUs; fuel switching from coal to natural gas at affected EGUs, either completely (conversion) or partially (co-firing); and carbon capture and storage by affected EGUs. One reason for not proposing to consider these measures to be part of the BSER was that they were more costly than the BSER measures. Another reason was that the emission reduction potential was limited compared to the potential available from the measures that were proposed to be included in the BSER. However, we also noted that circumstances could exist where these measures could be sufficiently attractive to deploy, and that the measures could be used to help affected EGUs achieve emission limits consistent with the BSER.

In the final rule, the EPA has reached determinations consistent with the proposal with respect to these measures: namely, that they do not merit inclusion in the BSER, but that they are capable of helping affected EGUs achieve compliance with standards of performance and are likely to be used for that purpose by some units. To the extent that they are selectively employed, they provide flexibility for the source category as a whole and for individual affected EGUs to achieve emission limits reflective of the BSER, as discussed above.

(1) *Heat rate improvement at affected EGUs other than coal-fired steam EGUs.*

Building block 1 reflects the opportunity to improve heat rate at coal-fired steam EGUs but not at other affected EGUs. As the EPA stated at proposal, the potential CO_2 reductions available from heat rate improvements at coal-fired steam EGUs are much larger than the potential CO_2 reductions available from heat rate improvements at other types of EGUs, and comments offered no persuasive basis for reaching a different conclusion. Nevertheless, we recognize that there may be instances where an owner/operator finds heat rate improvement to be an attractive option at a particular non-coal-fired affected EGU, and nothing in the rule prevents the owner/operator from implementing such a measure and using it to help achieve a standard of performance.

(2) *Carbon capture and storage at affected EGUs.*

Another approach for reducing CO_2 emissions per MWh of generation from affected EGUs is the application of carbon capture and storage (CCS) technology. Consistent with the June 2014 proposal, we are determining that use of full or partial CCS technology should not be part of the BSER for existing EGUs because it would be more expensive than the measures determined to be part of the BSER, particularly if applied broadly to the overall source category. At the same time, we note that retrofit of CCS technology may be a viable option at some individual facilities, particularly where the captured CO_2 can be used for enhanced oil recovery (EOR). For example, construction of one CCS retrofit application with EOR has already been completed at a unit at the Boundary Dam plant in Canada, and construction of another CCS retrofit application with EOR is underway at the W.A. Parish plant in Texas. We expect the costs of CCS to decline as implementation experience increases. CO_2 emission rate reductions achieved through retrofit of CCS technology would be available to help affected EGUs achieve emission limits consistent with the BSER. State plan considerations related to CCS are discussed in section VIII.I.2.a.

(3) *Fuel switching to natural gas at affected EGUs.*

In the proposal we discussed the opportunity to reduce CO_2 emissions at an individual affected EGU by switching fuels at the EGU, particularly by switching from coal to natural gas. Most coal-fired EGUs could be modified to burn natural gas instead, and the potential CO_2 emission reductions from this measure are large—approximately 40 percent in the case of conversion from 100 percent coal to 100 percent natural gas, and proportionately smaller for partial co-firing of coal with natural gas. The primary reason for not considering this measure part of the BSER, both at proposal and in this final rule, is that it is more expensive than the BSER measures. In particular, combusting natural gas in a steam EGU is less efficient and generally more costly than combusting natural gas in an NGCC unit. For the category as a whole, CO_2 emissions can be achieved far more cheaply by combusting additional natural gas in currently underutilized NGCC capacity and reducing generation from coal-fired steam EGUs (building block 2) than by combusting natural gas instead of coal in steam EGUs.

Some owner/operators are already converting some affected EGUs from coal to natural gas, and it is apparent that the measure can be attractive compared to alternatives in certain circumstances, such as when a unit must meet tighter unit-specific limits on emissions of non-GHG pollutants, the options for meeting those emission limits are costly, and retirement of the unit would necessitate transmission upgrades that are costly or cannot be completed quickly. CO_2 emission reductions achieved in these situations are available to help achieve emission limits consistent with the BSER.

(4) *Fuel switching to biomass at affected EGUs.*

Some affected EGUs may seek to co-fire qualified biomass with fossil fuels. The EPA recognizes that the use of some biomass-derived fuels can play an important role in controlling increases of CO_2 levels in the atmosphere. As with the other non-BSER measures discussed in this section, the EPA expects that use of biomass may be economically attractive for certain individual sources even though on a broader scale it would likely be more expensive or less achievable than the measures determined to be part of the BSER. Section VIII.I.2.c describes the process and considerations for states proposing to use different kinds of biomass in state plans.

(5) *Waste heat-to-energy conversion at affected EGUs.*

Certain affected EGUs in urban areas or located near industrial or commercial facilities with needs for thermal energy may be able add new equipment to capture some of the waste heat from their electricity generation processes and use it to create useful thermal output, thereby engaging in combined heat and power (CHP) production. While the set of affected EGUs in locations making this measure feasible may be limited, where feasible the potential CO_2 emission rate improvements can be substantial: Depending on the process used, the efficiency with which fuel is converted to useful energy can be increased by 25 percent or more. The final rule allows an owner/operator applying CHP technology to an affected EGU to account for the increased efficiency by counting the useful thermal output as additional MWh of generation, thereby lowering the unit's computed emission rate and assisting with achievement of an emission rate-based standard of performance. (The EPA notes that unless the unit also reduced its fuel usage, the addition of the capability to capture waste heat and produce useful thermal output would not reduce the unit's mass emissions and therefore would not directly help the unit achieve a mass-based standard of performance.[441])

b. *Non-BSER measures that reduce CO_2 emissions by reducing fossil fuel-fired generation.*

A second group of non-BSER measures has the potential to reduce CO_2 emissions from affected EGUs by reducing the amount of generation from those EGUs. As discussed above, under a section 111(d) plan with mass-based standards of performance, no special action is required to enable measures of this nature to help the source category as a whole and individual affected EGUs achieve their emission limits, because the CO_2-reducing effects are captured in monitored stack emissions. However, under a section 111(d) plan with rate-based standards of performance, affected EGUs would need to acquire ERCs based on the non-BSER activities that could be averaged into their emission rate computations for purposes of determining compliance with their standards of performance.

(1) *Demand-side EE.*

One of the major approaches available for achieving CO_2 emission reductions from the utility power sector is demand-side EE. In the June 2014 proposal, the EPA identified demand-side EE as one of the four proposed building blocks for the BSER. We continue to believe that significant emission reductions can be achieved by the source category through use of such measures at reasonable costs. In fact, we believe that the potential emission reductions from demand-side EE rival those from building blocks 2 and 3 in magnitude, and that demand-side EE is likely to

[441] However, the EPA notes that a state could establish a mechanism for encouraging affected EGUs to apply CHP technology under a mass-based plan, for example, through awards of emission allowances to CHP projects.

represent an important component of some state plans, particularly in instances where a state prefers to develop a plan reflecting the state measures approach discussed in section VIII below. We also expect that many sources would be interested in including demand-side EE in their compliance strategies to the extent permitted, and we received comment that it should be permitted.

For the reasons discussed in section V.B.3.c.(8) below, the EPA has determined not to include demand-side EE in the BSER in this final rule. However, the final rule authorizes generation avoided through investments in demand-side EE to serve as the basis for issuance of ERCs when appropriate conditions are met. In section VIII.K below, the EPA sets out the minimum criteria that must be satisfied for generation and issuance of a valid ERC based upon implementation of new demand-side EE programs. Those criteria generally concern ensuring that the physical basis for the ERC—in this case, generation avoided through implementation of demand-side EE measures—is adequately evaluated, measured, and verified and that there is an adequate administrative process for tracking credits.

Through their authority over legal requirements such as building codes, states have the ability to drive certain types of demand-side EE measures that are beyond the reach of private-sector entities. The EPA recognizes that, by definition, this type of measure is beyond the ability of affected EGUs to invest in either directly or through bilateral arrangements. However, the final rule also authorizes generation avoided through such state policies to serve as the basis for issuance of ERCs that in turn can be used by affected EGUs. The section 111(d) plan would need to include appropriate provisions for evaluating, measuring, and verifying the avoided MWh associated with the state policies, consistent with the criteria discussed in section VIII.K below.

(2) *New or uprated nuclear generating capacity.*

In the June 2014 proposal, the EPA included generation from the five nuclear units currently under construction as part of the proposed BSER. As discussed above in section V.A.3.c., upon consideration of comments, we have determined that generation from these units should not be part of the BSER. However, we continue to observe that the zero-emitting generation from these units would be expected to replace generation from affected EGUs and thereby reduce CO_2 emissions, and the continued commitment of the owner/operators to completion of the units is essential in order to realize that result. Accordingly, a section 111(d) plan may rely on ERCs issued on the basis of generation from these units and other new nuclear units. For the same reason, a plan may rely on ERCs issued on the basis of generation from uprates to the capacity of existing nuclear units. Requirements for state plan provisions intended to serve this purpose are discussed in section VIII.K.

(3) *Zero-emitting RE generating technologies not reflected in the BSER.*

The range of available zero-emitting RE generating technologies is broader than the range of RE technologies determined to be suitable for use in quantification of building block 3 as an element of the BSER. Examples of additional zero-emitting RE technologies not included in the BSER that could be used to achieve emission limits consistent with the BSER include offshore wind, distributed solar, and fuel cells. These technologies were not included in the range of RE technologies quantified for the BSER because they are generally more expensive than the measures that were included and the other measures in the BSER. However, these technologies are equally capable of replacing generation from affected EGUs and thereby reducing CO_2 emissions. Further, as with any technology, there are likely to be certain circumstances where the costs of these technologies are more attractive relative to alternatives, making the technologies likely to be deployed to some extent. Indeed, distributed solar is already being widely deployed in much of the U.S. and offshore wind, while still unusual in this country, has been extensively deployed in some other parts of the world. We expect innovation in RE generating technologies to continue, making such technologies even more attractive over time. A section 111(d) plan may rely on ERCs issued on the basis of generation from new and uprated installations of these technologies. The necessary state plan provisions are discussed in section VIII.K.

(4) *Non-zero-emitting RE generating technologies.*

Generation from new or expanded facilities that combust qualified biomass or biogenic portions of municipal solid waste (MSW) to produce electricity can also replace generation from affected EGUs and thereby control CO_2 levels in the atmosphere.[442] While the EPA believes it is reasonable to consider generation from these fuels and technologies to be forms of RE generation, the fact that they can produce stack emissions containing CO_2 means that a section 111(d) plan seeking to permit use of such generation to serve as the basis for issuance of ERCs must include appropriate consideration of feedstock characteristics and climate benefits. Specifically, the use of some kinds of biomass has the potential to offer a wide range of environmental benefits, including carbon benefits. However these benefits can only be realized if biomass feedstocks are sourced responsibly and attributes of the carbon cycle related to the biomass feedstock are taken into account. Section VIII.I.2.c describes the process and considerations for states proposing to use biomass in state plans. Section VIII.K describes additional provisions related to ERCs.

(5) *Waste heat-to-electricity conversion at non-affected facilities.*

Industrial facilities that install new equipment to capture waste heat from an existing combustion process and then use the waste heat to generate electricity—a form of combined heat and power (CHP) production—can produce generation that replaces generation from affected EGUs and thereby reduces CO_2 emissions. A section 111(d) plan may rely on ERCs issued on the basis of generation of this nature provided that the facility does not generate and sell sufficient electricity to qualify as a new EGU for purposes of section 111(b) and is not covered under section 111(d) for another source category. More information is provided in section VIII.K.

(6) *Reduction in transmission and distribution line losses.*

Reductions of electricity line losses incurred from the transmission and distribution system between the points of generation and the points of consumption by end-users allow the same overall demand for electricity services to be met with a smaller overall quantity of electricity generation. Such reductions in generation quantities would tend to reduce generation by affected EGUs, thereby reducing CO_2 emissions. The opportunity for improvement is large because, on average, line losses account for approximately seven percent of all electricity generation. The EPA recognizes that, in general, only the

[442] The EPA and many states have recognized the importance of integrated waste materials management strategies that emphasize a hierarchy of waste prevention and all other productive uses of waste materials to reduce the volume of disposed waste materials (see section VIII for more discussion of waste-to-energy strategies).

owner/operators of the transmission and distribution facilities have the ability to undertake line loss reduction investments, and that merchant generators may have little opportunity to engage a contractor to pursue such opportunities on a bilateral basis. Nevertheless, for entities that do have the opportunity to make such investments, generation avoided through investment that reduces transmission and distribution line losses may serve as the basis for issuance of ERCs that in turn can be used by affected EGUs. Further information is provided in section VIII.K.

7. Severability

The EPA intends that the components of the BSER summarized above be severable. It is reasonable to consider the building blocks severable because the building blocks do not depend on one another. Building blocks 2 and 3 are feasible and demonstrated means of reducing CO_2 emissions from the utility power sector that can be implemented independently of the other building blocks. If implemented in combination with at least one of the other building blocks, building block 1 is also a feasible and demonstrated means of reducing CO_2 emission from the utility power sector.[443] As discussed in sections V.C. through V.E. below, we have determined that each building block is independently of reasonable cost whether or not the other building blocks are applied, and that alternative combinations of the building blocks are likewise of reasonable cost, and we have determined reasonable schedules and stringencies for implementation of each building block independently, based on factors that generally do not vary depending on the implementation of other building blocks.

Further, building block 2, building block 3, and all combinations of the building blocks (implemented on the schedules and at the stringencies determined to be reasonable in this rule) would achieve meaningful degrees of emission reductions,[444] although less than the combination of all three building blocks. No combination of the building blocks would lead to adverse non-air environmental or energy impacts or impose a risk to the reliability of electricity supplies.

In the event that a court should deem building block 2 or 3 defective, but not both, the standards and state goals can be recomputed on the basis of the remaining building blocks. All of the data and procedures necessary to determine recomputed state goals using any combination of the building blocks are set forth in the CO_2 Emission Performance Rate and Goal Computation TSD for the CPP Final Rule available in the docket.

B. Legal Discussion of Certain Aspects of the BSER

This section includes a legal analysis of various aspects of EPA's determination of the BSER, including responses to some of the major adverse comments. These aspects include (1) the EPA's authority to determine the BSER; (2) the approach to subcategorization; (3) the EPA's basis for determining that building blocks 2 and 3 qualify as part of the BSER under CAA sections 111(d)(1) and (a)(1), notwithstanding commenters' arguments that these building blocks cannot be considered part of the BSER because they are not based on measures integrated into the design or operation of the affected source's own production processes or methods or because they are dependent on actions by entities other than the affected source; (4) the relationship between an affected EGU's implementation of building blocks 2 and 3 and CO_2 emissions reductions; (5) how reduced generation relates to the BSER; (6) reasons why, contrary to assertions by commenters, this rule is within the EPA's statutory authority, is not inconsistent with the Federal Power Act or state laws governing public utility commissions, and does not result in what the U.S. Supreme Court described as ''an enormous and transformative expansion in [the] EPA's regulatory authority''; [445] and (7) reasons that, contrary to assertions by commenters, the stringency of the BSER for this rule for CO_2 emissions from existing affected EGUs is not inconsistent with the stringency of the BSER for the rules the EPA is promulgating at the same time for CO_2 emissions from new or modified affected EGUs.

1. The EPA's Authority To Determine the BSER

In this section, we explain why the EPA, and not the states, has the authority to determine the BSER and, therefore, the level of emission limitation required from the existing sources in the source category in section 111(d) rulemaking and the associated state plans.

CAA section 111(d)(1) requires the EPA to establish a section 110-like procedure under which each state submits a plan that ''establishes standards of performance for any existing source of air pollutant'' and ''provides for the implementation and enforcement of such standards of performance.'' As CAA section 111(d) was originally adopted in the 1970 CAA Amendments, however, state plans were required to establish ''emission standards''—an undefined term—rather than ''standards of performance,'' a term that was limited to CAA section 111(b).[446] The 1970 provision was in effect when the EPA issued the 1975 implementing regulations for CAA section 111(d),[447] which remain in effect to this day.

These regulations establish a cooperative framework that is similar to that under CAA section 110. First, the EPA develops ''emission guidelines'' for source categories, which are defined as a final guideline document reflecting ''the degree of emission reduction achievable through the application of the best system of emission reduction . . . which the Administrator has determined has been adequately demonstrated.'' Then, the states submit implementation plans to regulate any existing sources.[448]

The preamble to these regulations carefully considered the allocation of responsibilities as between the EPA and the states for purposes of CAA section 111(d), and concluded that the EPA is responsible for determining the level of emission limitation from the source category, while the states have the responsibility of assigning emission requirements to their sources that assured their achievement of that level of emission limitation.[449] The EPA

[443] The heat rate improvement measures included in building block 1 are capable of being implemented independently of the measures in the other building blocks but, as discussed earlier, unless at least one other building block is also implemented, a ''rebound effect'' arising from improved competitiveness and increased generation at the EGUs implementing heat rate improvements could weaken or potentially even eliminate the ability of building block 1 to achieve CO_2 emission reductions.

[444] This conclusion would not extend to a BSER comprising solely building block 1, in part because of the possibility of rebound effects discussed earlier.

[445] *Util. Air Reg. Group* v. *EPA,* 134 S. Ct. 2427, 2444 (2014).

[446] *See* 1970 CAA Amendments, § 4, 84 Stat. at 1683–84. Subsequently, in 1977, Congress replaced the term ''emission standard'' with ''standards of performance.'' *See* 1977 CAA Amendments, § 109, 91 Stat. at 699.

[447] *See* ''State Plans for the Control of Certain Pollutants From Existing Facilities,'' 40 FR 53340 (Nov. 17, 1975).

[448] *See* ''State Plans for the Control of Certain Pollutants From Existing Facilities,'' 40 FR 53340 (Nov. 17, 1975).

[449] As we made clear in the proposed rulemaking, we are not re-opening these regulations (on the

explained ''that some substantive criterion was intended to govern not only the Administrator's promulgation of standards but also [her] review of state plans.'' [450] The EPA added, ''it would make no sense to interpret [CAA] section 111(d) as requiring the Administrator to base approval or disapproval of state plans solely on procedural criteria. Under that interpretation, states could set extremely lenient standards—even standards permitting greatly increased emissions—so long as [the] EPA's procedural requirements were met.'' [451] The EPA concluded that ''emission guidelines, each of which will be subjected to public comment before final adoption, will serve [the] function'' of providing substantive criteria ''in advance to the states, to industry, and to the general public'' to aid states in ''developing and enforcing control plans under [CAA] section 111(d).'' [452] Thus, the implementing regulations make clear that the EPA is responsible for determining the level of emission limitation that the state plans must achieve.

In 1977, Congress revised CAA section 111(d) to require that the states adopt ''standards of performance,'' as defined under CAA section 111(a)(1). As noted above, a standard of performance is defined as ''a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which . . . *the Administrator determines* has been adequately demonstrated.'' (Emphasis added.) By its terms, this provision provides that the EPA has the responsibility of determining whether the ''best system of emission reduction'' is ''adequately demonstrated.'' By giving the EPA this responsibility, this provision is clear that Congress assigned the role of determining the ''best system of emission reduction'' to the EPA. Even if the provision may be considered to be silent or ambiguous on that question, the EPA reasonably interprets the provision to assign the responsibility of identifying the ''best system of emission reduction'' to the Administrator for the same reasons discussed in the preamble to the 1975 implementing regulations.

In addition, in the legislative history of the 1977 CAA Amendments, when Congress replaced the term ''emission standards'' under CAA section 111(d)(1) with the term ''standards of performance,'' Congress endorsed the overall approach of the implementing regulations, which lends further credence to the proposition that the EPA has the responsibility for determining the ''best system of emission reduction'' and the amount of emission limitation from the existing sources. Specifically, in the House report that introduced the substantive changes to CAA section 111, the Committee explained that ''[t]he Administrator would establish *guidelines as to what the best system* for each category of existing sources *is.''* [453] States, on the other hand, ''would be responsible for determining the applicability of such *guidelines* to any particular source or sources.'' [454] The use of the term ''guidelines,'' which does not appear in CAA section 111(d), indicates Congress was aware of and approved of the approach taken in the EPA's implementing regulations for establishing guidelines, which determine the BSER. At a minimum, if Congress disapproved of the EPA's implementing regulations, we would not expect the House report to adopt the EPA's terminology to clarify CAA section 111(d).

In addition, Congress expressly referred to our ''guidelines'' in CAA section 129, added as part of the 1990 CAA Amendments. Congress added CAA section 129 to address solid waste combustion and specifically directed the Administrator to establish ''*guidelines* (under section 111(d) and this section) and other requirements applicable to existing units.'' [455] This reference also indicates that Congress was aware of and approved the EPA's regulations under section 111(d).

The EPA has followed the same approach described in the implementation regulations in all its rulemakings under section 111(d). Thus, in all cases, the EPA has identified the type of emission controls for the source category and the level of emission limitation based on those controls.[456] The EPA's longstanding and consistent interpretation of CAA section 111(d) is also ''evidence showing that the statute is in fact not ambiguous,'' and that the EPA's interpretation should be adopted.[457]

Lastly, this interpretation is consistent with the Supreme Court's reading of CAA section 111(d) in *American Electric Power Co.* There, the Court explained that ''EPA issues emissions guidelines, see 40 CFR 60.22, .23 (2009); in compliance with those guidelines and subject to federal oversight, the States then issue performance standards for stationary sources within their jurisdiction, § 7411(d)(1).'' [458]

As noted in the response to comment document, some commenters agreed with our interpretation, just discussed, while others argued that the states should be given the authority to determine the best system of emission reduction and, therefore, the level of emission limitation from their sources. For the reasons just discussed, this latter interpretation is an incorrect interpretation of CAA section 111(d)(1) and (a)(1), and we are not compelled to abandon our longstanding practice.

2. Approach to Subcategorization

As noted above, in this rule, we are treating all fossil fuel-fired EGUs as a single category, and, in the emission

issue of the authority to determine the BSER or any other issue, unless specifically indicated otherwise) in this rulemaking, and our discussion of these regulations in responding to comments does not constitute a re-opening.

[450] ''State Plans for the Control of Certain Pollutants from Existing Facilities,'' 40 FR 53340, 53342 (Nov. 17, 1975).

[451] ''State Plans for the Control of Certain Pollutants from Existing Facilities,'' 40 FR 53340, 53343 (Nov. 17, 1975).

[452] ''State Plans for the Control of Certain Pollutants from Existing Facilities,'' 40 FR 53340, 53343 (Nov. 17, 1975).

[453] H.R. Rep. No. 95–294, at 195 (May 12, 1977) (emphasis added).

[454] H.R. Rep. No. 95–294, at 195 (May 12, 1977) (emphasis added).

[455] CAA section 129(a)(1)(A) (emphasis added).

[456] *See* 40 CFR part 60, subpart Ca (large municipal waste combustors), 56 FR 5514 (Feb. 11, 1991), 40 CFR 60.30a–.39a (subsequently withdrawn and superseded by Subpart Cb, see 60 FR 65387 (Dec. 19, 1995)); Subpart Cb (large municipal waste combustors constructed on or before September 20, 1994), 60 FR 65387 (Dec. 19, 1995), 40 CFR 60.30b–.39b (as amended in 1997, 2001, and 2006); Subpart Cc (municipal solid waste landfills), 61 FR 9905 (Mar. 12, 1996), 40 CFR 60.30c–.36c (as amended in 1998, 1999, and 2000); Subpart Cd (sulfuric acid production units), 60 FR 65387 (Dec. 19, 1995), 40 CFR 60.30d–.32d; Subpart Ce (hospital/medical/infectious waste incinerators), 62 FR 48348 (Sept. 15, 1997), 40 CFR 60.30e–.39e (as amended in 2009 and 2011); Subpart BBBB (small municipal waste combustion units constructed on or before August 30, 1999), 65 FR 76738 (Dec. 6, 2000), 40 CFR 60.1500–.1940; Subpart DDDD (commercial and industrial solid waste incineration units that commenced construction on or before November 30, 1999), 65 FR 75338 (Dec. 1, 2000), 40 CFR 60.2500–.2875 (as amended in 2005, 2011, and 2013); Subpart FFFF (other solid waste incineration units that commenced construction on or before December 9, 2004), 70 FR 74870 (Dec. 16, 2005), 40 CFR 60.2980–.3078 (as amended in 2006); Subpart HHHH (coal-electric utility steam generating units), 70 FR 28606 (May 18, 2005) (subsequently vacated by the D.C. Circuit in *New Jersey* v. *EPA,* 517 F.3d 574 (D.C. Cir. 2008)); Subpart MMMM (existing sewage sludge incineration units), 76 FR 15372 (Mar. 21, 2011), 40 CFR 60.5000–.5250; ''Phosphate Fertilizer Plants, Final Guideline Document Availability,'' 42 FR 12022 (Mar. 1, 1977) (not codified); ''Kraft Pulp Mills; Final Guideline Document; Availability,'' 44 FR 29828 (May 22, 1979) (not codified); and ''Primary Aluminum Plants; Availability of Final Guideline Document,'' 45 FR 26294 (Apr. 17, 1980) (not codified).

[457] Scalia, Antonin, *Judicial Deference to Administrative Interpretations of Law,* 1989 Duke L.J. 511, 518; see *Riverkeeper* v. *Entergy,* 556 U.S. 208, 235 (2009).

[458] *Am. Elec. Power Co.* v. *Connecticut,* 131 S. Ct. 2527, 2537–38 (2011).

guidelines that we are promulgating with this rule, we are treating steam EGUs and combustion turbines as separate subcategories. We are determining the BSER for steam EGUs and the BSER for combustion turbines, and applying the BSER to each subcategory to determine a performance rate for that subcategory. We are not further subcategorizing among different types of steam EGUs or combustion turbines.

This approach is fully consistent with the provisions of section 111(d), which simply require the EPA to determine the BSER, do not prescribe the method for doing so, and are silent as to subcategorization. This approach is also fully consistent with other provisions in CAA section 111, which require the EPA first to list source categories that may reasonably be expected to endanger public health or welfare [459] and then to regulate new sources within each such source category,[460] and which grant the EPA discretion whether to subcategorize new sources for purposes of determining the BSER.[461]

For this rule, our approach of subcategorizing between steam EGUs and combustion turbines is reasonable because building blocks 1 and 2 apply only to steam EGUs. No further subcategorization is appropriate because each affected EGU can achieve the performance rate by implementing the BSER. Specifically, as noted, each affected EGU may take a range of actions including investment in the building blocks, replacing or reducing generation, and emissions trading, as enabled or facilitated by the implementation programs the states adopt. Further, in the case of a rate-based state plan, several other compliance options not included in the BSER for this rule are also available to all affected sources, including investment in demand-side EE measures. Such compliance options help affected sources achieve compliance under a mass-based plan, even if indirectly. Our approach to subcategorization in this rule is consistent with our approach to subcategorization in previous section 111 rules for this industry, in which we determined whether or not to subcategorize on the basis of the ability of affected EGUs with different characteristics (*e.g.,* size or type of fuel used) to implement the BSER and achieve the emission limits).[462]

In addition, there are numerous possible criteria to use in subcategorizing, including, among others, subcategorizing on the basis of age; size; steam conditions (*i.e.,* subcritical or supercritical); type of fuel, including type of coal (*i.e.,* lignite, bituminous, and sub-bituminous), and coal refuse; and method of combustion (*i.e.,* fluidized bed combustion, pulverized coal combustion, and gasification). In addition, there are different possible combinations of those categories. At least some of those criteria do not have logical cut-points. Furthermore, we have not been presented with, nor can we discern, a method of subcategorizing based on these or other criteria that is appropriate in light of the BSER for the affected EGUs and their ability to meet the emission limits. Moreover, our approach of not further subcategorizing as between different types of steam EGUs or combustion turbines reflects the reasonable policy that affected EGUs with higher emission rates should reduce their emissions by a greater percentage than affected EGUs with lower emission rates, and can do so by implementing the BSER we are identifying.

In addition, a section 111(d) rule presents less of a need to subcategorize because the states retain great flexibility in assigning standards of performance to their affected EGUs. Thus, a state can, if it wishes, impose different emission reduction obligations on its sources, as long as the overall level of emission limitation is at least as stringent as the emission guidelines, as discussed below. This means that if a state is concerned that its different sources have different capabilities for compliance, it can adjust the standards of performance in imposes on its sources accordingly.

3. Building Blocks 2 and 3 as a ''System of Emission Reduction''

a. *Overview.*

As we explain above, the emission performance rates that we include in this rule's emission guidelines are achievable by the affected EGUs through the application of the BSER, which includes the three building blocks. Commenters object that building blocks 2 (generation shift) and 3 (RE) cannot, as a legal matter, be considered part of the BSER under CAA section 111(d)(1) and (a)(1). These commenters explain that in their view, under CAA section 111, the emission performance rates must be based on, and therefore the BSER must be limited to, methods for emission control that the owner/operator of the affected source can integrate into the design or operation of the source itself, and cannot be based on actions taken beyond the source or actions involving third-party entities.[463] For these reasons, these commenters argue that the phrase ''system of emission reduction'' cannot be

---

[459] CAA section 111(b)(1)(A).

[460] CAA section 111(b)(1)(B).

[461] CAA section 111(b)(2).

[462] *Compare* ''Revision of Standards of Performance for Nitrogen Oxide Emissions From New Fossil-Fuel Fired Steam Generating Units; Revisions to Reporting Requirements for Standards of Performance for New Fossil-Fuel Fired Steam Generating Units: Final Rule,'' 63 FR 49442 (Sept. 16, 1998) *and* ''Proposed Revision of Standards of Performance for Nitrogen Oxide Emissions From New Fossil-Fuel Fired Steam Generating Units: Proposed Revisions,'' 62 FR 36948, 36943 (July 9, 1997) (establishing a single NO_X emission limit for new fossil-fuel fired steam generating units, and not subcategorizing, because the affected units could implement the BSER of SCR and achieve the promulgated emission limits) *with* ''National Emission Standards for Hazardous Air Pollutants From Coal and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units: Final Rule,'' 77 FR 9304 (Feb. 16, 2012) (MATS rule) *and* ''National Emission Standards for Hazardous Air Pollutants From Coal and Oil-Fired Electric Utility Steam Generating Units and Standards of performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units: Proposed Rule,'' 76 FR 24976, 25036–37 (May 3, 2011) (subcategorizing coal fired units designed to burn coal with greater than or equal to 8,300 Btu/lb (for Hg emissions only), coal-fired units designed to burn coal with less than 8,300 Btu/lb (for Hg emissions only), IGCC units, liquid oil units, and solid oil-derived units; evaluating ''subcategorization of lignite coal vs. other coal ranks; subcategorization of Fort Union lignite coal vs. Gulf Coast lignite coal vs. other coal ranks; subcategorization by EGU size (*i.e.,* MWe); subcategorization of base load vs. peaking units (*e.g.,* low capacity utilization units); subcategorization of wall-fired vs. tangentially-fired units; and subcategorization of small, non-profit-owned units vs. other units;'' but deciding not to adopt those latter subcategorizations).

[463] *See, e.g.,* comments by UARG at 6–7 (''Standards promulgated under section 111 must be source-based and reflect measures that the source's owner can integrate into the design or operation of the source itself. A standard cannot be based on actions taken beyond the source itself that somehow reduce the source's utilization.''); comments by UARG at 31 (the building blocks other than building block 1 take a '' 'beyond-the-source' approach'' and ''impermissibly rely on measures that go beyond the boundaries of individual affected EGUs and that are not within the control of individual EGU owners and operators''); comments by UARG at 33 (the ''system'' of emission reduction ''can refer only to reductions resulting from measures that are incorporated into the source itself;'' section 111 is ''designed to improve the emissions performance of new and existing sources in specific categories based on the application of achievable measures implemented in the design or production process of the source at reasonable cost.''); comments by American Chemistry Council et al. (''Associations'') at 60–61 (EPA's proposed BSER analysis is unlawful because it ''looks beyond the fence line of the fossil fuel-fired EGUs that are the subject of this rulemaking;'' ''the standard of performance must . . . be limited to the types of actions that can be implemented directly by an existing source within [the appropriate] class or category.'').

interpreted to include building blocks 2 and 3.

We disagree with these comments, and note that other commenters were supportive of our determination to include building blocks 2 and 3. Under CAA section 111(d)(1) and (a)(1), the EPA's emission guidelines must establish achievable emission limits based on the ''best system of emission reduction . . . adequately demonstrated.'' While some commenters assert that emission guidelines must be limited in the manner summarized above, the phrase ''system of emission reduction,'' by its terms and when read in context, contains no such limits. To the contrary, its plain meaning is deliberately broad and is capacious enough to include actions taken by the owner/operator of a stationary source designed to reduce emissions from that affected source, including actions that may occur off-site and actions that a third party takes pursuant to a commercial relationship with the owner/operator, so long as those actions enable the affected source to achieve its emission limitation. Such actions include the measures in building blocks 2 and 3, which, when implemented by an affected source, enable the source to achieve their emission limits because of the unique characteristics of the utility power sector. For purposes of this rule, we consider a ''system of emission reduction''—as defined under CAA section 111(a)(1) and applied under CAA section 111(d)(1)—to encompass a broad range of pollution-reduction actions, which includes the measures in building blocks 2 and 3. Furthermore, the measures in building blocks 2 and 3 fall squarely within EPA's historical interpretation of section 111, pursuant to which the focus for the BSER has been on how to most cleanly produce a good, not on how much of the good should be produced.

Our interpretation that a ''system of emission reduction'' is broad enough to include the measures in building blocks 2 and 3 is supported by the following: Our interpretation of the phrase ''system of emission reduction'' is consistent with its plain meaning and statutory context; our interpretation accommodates the very design of CAA section 111(d)(1), which covers a range of source categories and air pollutants;[464] our interpretation is supported by the legislative history of CAA section 111(d)(1) and (a)(1), which indicates Congress's intent to give the EPA broad discretion in determining the basis for CAA section 111 control requirements, particularly for existing sources, and Congress's intent to authorize the EPA to consider measures that could be carried out by parties other than the affected sources; and our interpretation is reasonable in light of comparisons to CAA provisions that give the EPA similar authority to consider such measures and to CAA provisions that would preclude the EPA from considering such measures.

In addition to the reasons stated above, the EPA's interpretation is also reasonable for the following reasons: (i) Building blocks 2 and 3 fit well within the structure and economics of the utility power sector. (ii) Fossil fuel-fired EGUs are already implementing the measures in these building blocks for various reasons, including for purposes of reducing CO_2 emissions. (iii) Interpreting the phrase ''system of emission reduction'' to incorporate building blocks 2 and 3 is consistent with (a) other provisions in the CAA, including the acid rain provisions in Title IV and the SIP provisions in CAA section 110, along with the EPA's regulations implementing the CAA SIP requirements concerning interstate transport and regional haze, each of which is based on at least some of the same measures included in building blocks 2 and 3; (b) prior EPA action under CAA section 111(d), including the 2005 Clean Air Mercury Rule,[465] which is based on some of the same measures in building blocks 2 and 3; (c) the various provisions of the CAA that authorize emissions trading, because emissions trading entails a source meeting its emission limitation based on the actions of another entity; and (d) the pollution prevention provisions of the CAA, which make clear that a primary goal of the CAA is to encourage federal and state actions that reduce or eliminate, through any measures, the amount of pollution produced at the source.[466] (iv) Lastly, interpreting the phrase ''system of emission reduction'' to authorize the EPA, in formulating its BSER determination, to weigh a broad range of emission-reducing measures that includes building blocks 2 and 3 is consistent with Congress's intent to address urgent environmental problems and to protect public health and welfare against risks, as well as Congress's expectation that American industry would be able to develop the innovative solutions necessary to protect public health and welfare.

Congress passed the CAA, including its several amendments, to protect public health and welfare from ''mounting dangers,'' including ''injury to agricultural crops and livestock, damage to and the deterioration of property, and hazards to air and ground transportation.''[467] In doing so, Congress established numerous programs to address air pollution problems and provided the EPA with guidance and flexibility in carrying out many of those programs. Even if we were to accept commenters' view that the system of emission reduction identified as best here is not integrated into the design or operation of the regulated sources, in the context of this industry and this pollutant it is reasonable to reject the narrow interpretation urged by some commenters that the ''system of emission reduction'' applicable to the affected EGUs must be limited to only those measures that can be integrated into the design or operation of the source itself. The plain language of the statute does not support such an interpretation, and to adopt it would limit the ''system of emission reduction'' to measures that are either substantially more expensive or substantially less effective at reducing emissions than the measures in building blocks 2 and 3, notwithstanding the absence of any statutory language imposing such a limit. Such a result would be contrary to the goals of the CAA and would ignore the facts that sources in the electric generation industry routinely address planning and operating objectives on a broad, multi-source basis using the measures in building blocks 2 and 3 and would seek to use building blocks 2 and 3 (as well as non-BSER measures) to comply with whatever emission standards are set as a result of this rule. Indeed, as already observed, building blocks 2 and 3 are already being used to reduce emissions, and to do so specifically by operation of the industry's inherent multi-source functions.

Although the BSER provisions are sufficiently broad to include, for affected EGUs, the measures in building blocks 2 and 3, they also incorporate significant constraints on the types of

[464] Because it is designed to apply to a range of air pollutants not regulated under other provisions, CAA section 111(d) may be described as a ''catch-all'' or ''gap-filler.'' As such, a ''system of emission reduction'' as applied under CAA section 111(d) should be interpreted flexibly to accommodate this role.

[465] This rule was vacated by the D.C. Circuit on other grounds. *New Jersey* v. *EPA,* 517 F.3d 574, 583–84 (D.C. Cir. 2008), *cert. denied sub nom. Util. Air Reg. Group* v. *New Jersey,* 555 U.S. 1169 (2009).

[466] As noted in the Legal Memorandum, in several of these rulemakings and in the course of litigation, the fossil fuel-fired electric power sector has taken positions that are consistent with the EPA's interpretation that the BSER may include building blocks 2 and 3.

[467] CAA section 101(a)(2).

measures that may be included in the BSER. We discuss those constraints at the end of this section. They include the section 111(d)(1) and (a)(1) requirements that emission reductions occur from the affected sources; that the emission performance standards for which the BSER forms the basis be achievable; that the system of emission reduction be adequately demonstrated; and that the EPA account for cost, non-air quality impacts, and energy requirements in determining the ''best'' system of emission reduction that is adequately demonstrated. The constraints included in these statutory requirements do not preclude building blocks 2 and 3 from the BSER. In interpreting these statutory requirements for determining the BSER, the EPA is consistent with past practice and current policy for both section 111 regulatory actions as well as regulatory actions under other CAA provisions for the electric power sector, under which the EPA has generally taken the approach of basing regulatory requirements on controls and measures designed to reduce air pollutants from the production process without limiting the aggregate amount of production. This approach has been inherent in our past interpretation and application of section 111 and we maintain this interpretation in this rulemaking.[468] While inclusion of building blocks 2 and 3 is consistent with our interpretation of the statutory requirements, inclusion of building block 4 is not, and for that reason, we are declining to include building block in the BSER. Finally, we briefly note additional constraints that focus the BSER identified for new sources under section 111(b) on controls that assure that sources are well-controlled at the time of construction.

b. *System of emission reduction as a broad range of measures.*

(1) *Plain meaning and context of ''system of emission reduction.''*

The phrase ''system of emission reduction'' appears in the definition of a ''standard of performance'' under CAA section 111(a)(1). That definition reads:

> a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.

Pursuant to this definition, it is clear that a ''system of emission reduction'' serves as the basis for emission limits embodied by CAA section 111 standards. For this reason, emission limits must be ''achievable'' through the ''application'' of the ''best'' ''system of emission reduction'' ''adequately demonstrated.'' Under CAA section 111(d)(1), such a limit is established for ''any existing source,'' which is defined as any existing ''building, structure, facility, or installation which emits or may emit any air pollutant.'' [469]

Although a ''system of emission reduction'' lays the groundwork for CAA section 111 standards, the term ''system'' is not defined in the CAA. As a result, we look first to its ordinary meaning.

Abstractly, the term ''system'' means a set of things or parts forming a complex whole; a set of principles or procedures according to which something is done; an organized scheme or method; and a group of interacting, interrelated, or interdependent elements.[470] As a phrase, ''system of emission reduction'' takes a broad meaning to serve a singular purpose: It is a set of measures that work together to reduce emissions.

When read in context, the phrase ''system of emission reduction'' carries important limitations: because the ''degree of emission limitation'' must be ''*achievable* through the *application* of the best system of emission reduction,'' (emphasis added), the ''system of emission reduction'' must be limited to a set of measures that work together to reduce emissions and that are implementable by the sources themselves.

As a practical matter, the ''source'' includes the ''owner or operator'' of any building, structure, facility, or installation for which a standard of performance is applicable. For instance, under CAA section 111(e), it is the ''owner or operator'' of a source who is prohibited from operating ''in violation of any standard of performance applicable to such source.'' [471]

Thus, a ''system of emission reduction'' for purposes of CAA section 111(d) means a set of measures that source owners or operators can implement to achieve an emission limitation applicable to their existing source.[472]

In contrast, a ''system of emission reduction'' does not include actions that only a state or other governmental entity could take that would have the effect of reducing emissions from the source category, and that are beyond the ability of the affected sources' owners/operators to take or control. Additionally, actions that a source owner or operator could take that would not have the effect of reducing emissions from the source category, such as purchasing offsets, would also not qualify as a ''system of emission reduction.''

Building blocks 2 and 3 each fall within the meaning of a ''system of emission reduction'' because they consist of measures that the owners/operators of the affected EGUs can implement to achieve their emission limits. In doing so, the affected EGUs will achieve the overall emission reductions the EPA identifies in this rule. We describe these building block 2 and 3 measures in detail elsewhere in this rule, including the specific actions that owners/operators of affected EGUs can take to implement the measures.

It should be noted that defining the scope of a ''system of emission reduction'' is not the end of our inquiry under CAA section 111(a)(1); rather, as noted above, a standard of performance must reflect the application of the ''*best* system of emission reduction . . . *adequately demonstrated.''* (Emphasis

[468] As we note in section V.A., this rulemaking presents a unique set of circumstances, including the global nature of CO_2 and the emission control challenges that CO_2 presents (which limit the availability and effectiveness of control measures), combined with the facts that the electric power industry (including fossil fuel-fired steam generators and combustion turbines) is highly integrated, electricity is fungible, and generation is substitutable (which all facilitate the generation shifting measures encompassed in building blocks 2 and 3). Our interpretation of section 111 as focusing on limiting emissions without limiting aggregate production must take into account those unique circumstances.

[469] *See* CAA section 111(d)(1) (applying a standard of performance to any existing source); (a)(6) (defining the term ''existing source'' as any stationary source other than a new source); and (a)(3) (defining the term ''stationary source'' as ''any building, structure, facility, or installation which emits or may emit any air pollutant,'' however, explaining that ''[n]othing in subchapter II [*i.e.,* Title II] of this chapter relating to nonroad engines shall be construed to apply to stationary internal combustion engines.'')

[470] *Oxford Dictionary of English* (3rd ed.) (2010), *available at http://www.oxforddictionaries.com/us/definition/american_english/system; see also* American Heritage Dictionary (5th ed.) (2013), *available at http://www.yourdictionary.com/system#americanheritage*; and *The American College Dictionary (C.L. Barnhart, ed. 1970) (''an assemblage or combination of things or parts forming a complex or unitary whole'').*

[471] While this section provides for enforcement in the context of new sources, a CAA section 111(d) plan must provide for the enforcement of a standard of performance for existing sources.

[472] Some commenters read the proposed rulemaking as taking the position that the phrase ''system of emission reduction'' includes anything whatsoever that reduces emissions, and criticized that interpretation as too broad. *See* UARG comment, at 3–4. We are not taking that interpretation here. In this final rule, we agree that the phrase should be limited to exclude, *inter alia,* actions beyond the ability of the owners/operators to control.

added.) Thus, in determining the BSER, the Administrator must first determine whether the available systems of emission reduction are ''adequately demonstrated,'' based on the criteria, described above, set out by Congress in the legislative history and the D.C. Circuit in case law. After identifying the ''adequately demonstrated'' systems of emission reduction, the Administrator then selects the ''best'' of these, based on several factors, including amount of emission reduction, cost, non-air quality health and environmental impact and energy requirements. Only after the Administrator weighs all of these considerations can she determine the BSER and, based on that, establish a standard of performance under CAA section 111(b) or an emission guideline under CAA section 111(d).

For purposes of this final rule, it is not necessary to enumerate all of the types of measures that do or do not constitute a ''system of emission reduction.'' What is relevant is that building blocks 2 and 3 each qualify as part of the ''system of emission reduction.'' As noted, they focus on supply-side activities and they each constitute measures that the affected EGUs can implement that will allow those EGUs to achieve the degree of emission limitation that the EPA has identified based on those building blocks. Further, these building blocks also satisfy the other statutory criteria enumerated in CAA section 111(a)(1).

(2) *Other indications that the BSER provisions encompass a broad range of measures.*

The EPA's plain meaning interpretation that the BSER provisions in CAA section 111(d)(1) and (a)(1) are designed to include a broad range of measures, including building blocks 2 and 3, is supported by several other indications in the CAA and the legislative history of section 111.

(a) *Scope of CAA section 111(d)(1).*

First, the broad scope of CAA section 111(d)(1) supports our interpretation of the BSER because a wide range of control measures is appropriate for the wide range of source categories and air pollutants covered under CAA section 111(d).

In the 1970 CAA Amendments, Congress established a regulatory regime for existing stationary sources of air pollutants that may be envisioned as a three-legged stool, designed to address ''three categories of pollutants emitted from stationary sources'': (1) Criteria pollutants (identified under CAA section 109 and regulated under section 110); (2) hazardous air pollutants (identified and regulated under section 112); and (3) ''pollutants that are (or may be) harmful to public health or welfare but are not'' criteria or hazardous air pollutants.[473] Congress enacted CAA section 111(d) to cover this third category of air pollutants and, in this sense, Congress designed it to apply to any air pollutants that were not otherwise regulated as toxics or NAAQS pollutants.[474] This would include air pollutants that the EPA might later, when more information became available, designate as NAAQS or hazardous air pollutants, as well as air pollutants that Congress may not have been aware of at the time.[475] In addition, the indications are that Congress expected CAA section 111(d) to be a significant source of regulatory activity, by some measures, more active than CAA section 112. This is evident because Congress expected that CAA section 111(d) would cover more air pollutants than either CAA section 109/110 (criteria pollutants) or CAA section 112 (hazardous air pollutants).[476] In addition, in the 1990 CAA Amendments, Congress enacted CAA section 129 to achieve emission reductions from a major source category, solid waste incinerators, and established CAA section 111(d) as the basic mechanism for that provision. The EPA subsequently promulgated a number of CAA section 129/111(d) rulemakings.[477] Finally, it should be noted that Congress designed CAA section 111(d) to cover a wide range of source categories—including any source category that the EPA identifies under subsection 111(b)(1)(A) as meeting the criteria of, in general, causing or contributing significantly to air pollution that may reasonably be anticipated to endanger public health or welfare—along with the wide range of air pollutants.

[473] 40 FR 53340, 53340 (Nov. 17, 1975) (EPA regulations implementing CAA section 111(d)).

[474] *See* S. Rep. No. 91–1196, at 20 (Sept. 17, 1970), 1970 CAA Legis. Hist. at 420 (''It should be noted that the emission standards for pollutants which cannot be considered hazardous (as defined in section 115 [*i.e.,* the bill's version of CAA section 112] could be established under section 114 [*i.e.,* the bill's version CAA section 111]. Thus, there should be no gaps in control activities pertaining to stationary source emissions that pose any significant danger to public health or welfare.'').

[475] *See* S. Rep. No. 91–1196, at 20 (Sept. 17, 1970), 1970 CAA Legis. Hist. at 420.

[476] *See* S. Rep. No. 91–1196, at 9; 18–20, 1970 CAA Legis. Hist. at 418–20. The Senate Committee Report identified 14 substances as subject to the provision that became section 111(d), four substances as hazardous air pollutants that would be regulated under the provision that became section 112, and 5 substances as criteria pollutants that would be regulated under the provisions that became sections 109–110 (and more ''as knowledge increases''). In particular, the Report recognized that in particular, relatively few air pollutants may qualify as hazardous air pollutants, but that other air pollutants that did not qualify as hazardous air pollutants would be regulated under what became section 111(d).

[477] *See, e.g.,* Standards of Performance for New Stationary Sources and Emission Guidelines for Existing Sources: Hospital/Medical/Infectious Waste Incinerators, 62 FR 48348, 48359 (Sept. 15, 1997); Standards of Performance for New Stationary Sources and Emission Guidelines for Existing Sources: Commercial and Industrial Solid Waste Incineration Units, 65 FR 75338, 75341 (Dec. 1, 2000).

Because Congress designed CAA section 111(d) to cover a wide range of air pollutants—including ones that Congress may not have been aware of at the time it enacted the provision—and a wide range of industries, it is logical that Congress intended that the BSER provision, as applied to CAA section 111(d), have a broad scope so as to accommodate the range of air pollutants and source categories.

(b) *Legislative history of CAA section 111.*

(i) *Breadth of ''system of emission reduction.''*

The phrase ''system of emission reduction,'' particularly as applied under CAA section 111(d), should be broadly interpreted consistent with its plain meaning but also in light of its legislative history. The version of CAA section 111(d)(1) that Congress adopted as part of the 1970 CAA Amendments read largely as CAA section 111(d)(1) does at present, except that it required states to impose ''emission standards'' on any existing source. (Congress replaced that term with ''standards of performance'' in the 1977 CAA Amendments.) The 1970 CAA Amendments version of CAA section 111(d)(1) neither defined ''emission standards'' nor imposed restrictions on the EPA in determining the basis for the emission standards.[478]

For new sources, CAA section 111(b)(1)(B), as enacted in the 1970 CAA Amendments (and as it largely still

[478] Although not defined under CAA section 111, the term was used in other provisions and defined in some of them. The term was defined under the CAA's citizen suit provision. *See* 1970 CAA Amendments, Pub. L. 91–604, § 12, 84 Stat. 1676, 1706 (Dec. 31, 1970) (defined as ''(1) a schedule or timetable of compliance, emission limitation, standard of performance or emission standard, or (2) a control or prohibition respecting a motor vehicle fuel or fuel additive . . . . .''). Congress also used it in the CAA's NAAQS provisions and in CAA section 112. Under the CAA's NAAQS provisions (*i.e.,* the ''Ambient Air Quality and Emission Standards'' provisions), Congress directed the EPA to issue information on ''air pollution control techniques,'' and include data on ''available technology and alternative methods of prevention and control of air pollution'' as well as on ''alternative fuels, processes, and operating methods which will result in elimination or significant reduction of emissions.'' *Id.,* § 4, 84 Stat. at 1679. Similarly, under CAA section 112, the Administrator was required to ''from time to time, issue information on pollution control techniques for air pollutants'' subject to emission standards. *Id.,* 84 Stat. at 1685. These statements provide additional context for the term's broad intent.

reads), required the EPA to promulgate ''standards of performance,'' and defined that term, much like the present definition, as emission standards based on the ''best system of emission reduction . . . adequately demonstrated.'' This quoted phrase was not included in either the House or Senate versions of the provision, and, instead, was added during the joint conference between the House and Senate. The conference report accompanying the text offers no clarifications.

The House and Senate bills do, however, provide some insights. The House bill, H.R. 17255, would have required new sources of non-hazardous air pollutants to ''prevent and control such emissions to the fullest extent compatible with the available technology and economic feasibility, as determined by the Secretary.'' [479] The Senate bill, S. 4358, would have established ''Federal standards of performance for new sources,'' which, in turn, were to ''reflect the greatest degree of emission control which the Secretary determines to be achievable through application of the latest available control technology, processes, operating methods, *or other alternatives.''* [480] The Senate Committee Report explains that ''performance standards should be met through application of the latest available emission control technology or through *other means of preventing or controlling air pollution.''* [481] This Report further elaborates that the term ''standards of performance''

> refers to the degree of emission control which can be achieved through process changes, operation changes, direct emission control, *or other methods.* The Secretary should not make a technical judgment as to how the standard should be implemented. He should determine the achievable limits and let the owner or operator determine the most economic, acceptable *technique* to apply.[482]

Thus, the Senate bill clearly envisioned that standards of performance would not be based on a particular technology or even a particular method to prevent or control air pollution.[483] This vision contrasted with the House bill, which would have restricted performance standards to economically feasible technical controls.

Following the House-Senate Conference, the enacted version of the legislation defined a ''standard of performance'' to mean

> a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the *best system of emission reduction* which (taking into account the cost of achieving such reduction) the Administrator determines has been adequately demonstrated.[484]

While the phrase ''system of emission reduction'' was not discussed in the Conference Report, an exhibit titled ''Summary of the Provisions of Conference Agreement on the Clean Air Amendments of 1970'' was added to the record during the Senate's consideration of the Conference Report and sheds some light on the phrase. According to the summary, ''[t]he agreement authorizes regulations to require that new major industry plants such as power plants, steel mills, and cement plants achieve a standard of emission performance based on the latest available control technology, processes, operating methods, and other alternatives.'' [485] In light of this summary, the phrase ''system of emission reduction'' appears to blend the broad spirit of S. 4358 (which required the ''latest available control technology, processes, operating methods, or other alternatives'') with the cost concerns identified in H.R. 17255 (which required consideration of ''economic feasibility'' when establishing federal emission standards for new stationary sources). This history strongly suggests that Congress intended to authorize the EPA to consider a wide range of measures in calculating a standard of performance for stationary sources. At a minimum, there is no indication that Congress intended to preclude measures or actions such as the ones in building blocks 2 and 3 from the EPA's assessment of the BSER.

Notwithstanding this broad approach, as we discuss in the Legal Memorandum, the legislative history of the 1970 CAA Amendments also indicates that Congress intended that new sources be well-controlled at the source, in light of their expected lengthy useful lives.

In 1977, Congress amended CAA section 111(a)(1) to limit the types of controls that could be the basis of standards of performance for new sources to technological controls. Congress was clear, however, that existing source standards, which were no longer developed as ''emission standards,'' would not be limited to technological measures. Specifically, the 1977 CAA Amendments revised CAA section 111(a)(1) to require all new sources to meet emission standards based on the reductions achievable through the use of the ''best technological system of continuous emission reduction.'' [486] According to the legislative history, [t]his mean[t] that new sources may not comply merely by burning untreated fuel, either oil or coal.'' [487] The new requirement stemmed in part from Congress's concern over the shocks that the country experienced during the 1973–74 Arab Oil Embargo, which led Congress to revise CAA section 111 to ''encourage and facilitate the increased use of coal, and to reduce reliance (by new and old sources alike), upon petroleum to meet emission requirements.'' [488] Imposing a new technological requirement (along with a new percentage reduction requirement) under CAA section 111 was designed to ''force new sources to burn high-sulfur fuel thus freeing low-sulfur fuel for use in existing sources where it is harder to control emissions and where low-sulfur fuel is needed for compliance.'' [489] Congress nonetheless recognized that despite narrowing new source standards to the best ''technological system of continuous emission reduction,'' many ''innovative approaches may in fact reduce the economic and energy impact of emissions control,'' and the Administrator should still be encouraged to consider other technologically based techniques for emissions reduction, including ''precombustion cleaning or treatment of fuels.'' [490] This is discussed in more detail below.

Despite these changes with respect to new sources, the 1977 CAA Amendments further reinforce the

[479] H.R. 17255, § 5, 1970 CAA Legis. Hist. at 921–22. The reference to ''Secretary'' was to the Secretary of Health Education and Welfare, which, at the time, was the agency with responsibility for air pollution regulations.

[480] S. 4358, § 6, 1970 Legis. Hist. at 554–55 (emphasis added).

[481] S. Rep. No. 91–1196, at 15–16 (Sept. 17, 1970), 1970 CAA Legis. Hist. at 415–16 (emphasis added).

[482] S. Rep. No. 91–1196, at 15–16 (Sept. 17, 1970), 1970 CAA Legis. Hist. at 415–16 (emphasis added).

[483] Notably, the Senate report identifies pollution control *and* pollution prevention as objectives of the Senate provision. Pollution prevention is discussed more generally below as a ''primary purpose'' of the CAA, however, the report makes clear that pollution prevention measures—which the EPA understands to include such measures as building blocks 2 and 3—are appropriate under CAA section 111.

[484] CAA section 111(a)(1) under the 1970 CAA Amendments (emphasis added).

[485] Sen. Muskie, S. Consideration of H.R. Conf. Rep. No. 91–1783 (Dec. 17, 1970), 1970 CAA Legis. Hist. at 130.

[486] CAA section 111(a)(1) (1977).

[487] H.R. Rep. No. 95–294 (May 12, 1977), 1977 CAA Legis. Hist. at 2659.

[488] H.R. Rep. No. 95–294 (May 12, 1977), 1977 CAA Legis. Hist. at 2659.

[489] *New Stationary Sources Performance Standards; Electric Utility Steam Generating Units,* 44 FR 33580, 33581–33582 (June 11, 1979).

[490] H.R. Rep. No. 95–294, at 189 (May 12, 1977), 1977 CAA Legis. Hist. at 2656.

notion that with respect to existing sources, the BSER was never intended to be narrowly applied. In 1977, Congress changed CAA section 111(d)(1) to require that states adopt ''standards of performance'' and made clear that such standards were to be based on the ''best system of continuous emission reduction . . . adequately demonstrated,'' [491] but generally maintained the breadth of that term. Although Congress inserted the word ''continuous'' into the phrase, Congress explained that ''standards in the Section 111(d) state plan would be based on the *best available means (not necessarily technological)* for categories of existing sources to reduce emissions.'' [492] This was intended to distinguish existing source standards from new source standards, for which ''the requirement for [BSER] has been more narrowly redefined as best technological system of continuous emission reduction.'' [493] [494]

In the 1990 CAA Amendments, Congress restored the 1970s vintage definition of a standard of performance as applied to both new and existing sources. With respect to existing sources, this had the effect of no longer requiring that the BSER be ''continuous.'' [495] Further, nothing in the 1990 CAA Amendments or their legislative history indicates that Congress intended to impose new constraints on the types of systems of emission reduction that could be considered under CAA section 111(d)(1) and (a)(1). In contrast, Congress retained the definition of the term ''technological system of continuous emission reduction,'' which means ''a technological process for production or operation by any source which is inherently low-polluting or nonpolluting,'' CAA section 111(a)(7)(A), or ''a technological system for continuous reduction of the pollution generated by a source before such pollution is emitted into the ambient air, including precombustion cleaning or treatment of fuels,'' CAA section 111(a)(7)(B).

That term continues to be used in reference to new sources in certain circumstances, under CAA section 111(b), (h), and (j).[496] However, it is not and never has been used to regulate existing sources. In this manner, the 1990 CAA Amendments further reinforce the breadth and flexibility of the phrase ''system of emission reduction,'' particularly as it applies to existing sources under CAA section 111(d).

For these reasons, the 1970, 1977, and 1990 legislative histories support the EPA's interpretation in this rule that the term is sufficiently broad to encompass building blocks 2 and 3.

(ii) *Reliance on actions taken by other entities.*

The legislative history supports the EPA's interpretation of ''system of emission reduction'' in another way as well: The legislative history makes clear that Congress intended that standards of performance for electric power plants could be based on measures implemented by other entities, for example, entities that ''wash,'' or desulfurize, coal (or, for oil-fired EGUs, that desulfurize oil). This legislative history is consistent with the EPA's view that the ''system of emission reduction'' may include actions taken by an entity with whom the owner/operator of the affected source enters into a contractual relationship as long as those actions allow the affected source to meet its emission limitation. By the same token, this legislative history directly refutes commenters' assertions that the phrase ''system of emission reduction'' must not include actions taken by entities other than the affected sources.[497]

As noted above, in the 1977 CAA Amendments, Congress revised the basis for standards of performance for new fossil fuel-fired stationary sources to be a ''technological system of continuous emission reduction,'' including ''precombustion cleaning or treatment of fuels.'' [498] Precombustion cleaning or treatment reduces the amount of sulfur in the fuel, which means that the fuel can be combusted with fewer SO_2 emissions, and that in turn means that the source can achieve a lower emission limit. Congress understood that these fuel cleaning techniques would not necessarily be accomplished at the affected source and, in revising CAA section 111(a)(1), wanted to ensure that such techniques would not be overlooked. For example, the 1977 House Committee report indicates that an assessment of the best technological system of continuous emission reduction for fossil fuel-fired power plants would include off-site or third-party pre-combustion techniques for reducing emissions at the source (''*e.g.,* various coal-cleaning technologies such as solvent refining, oil desulfurization *at the refinery*'').[499]

[491] CAA section 111(a)(1)(C) under the 1977 CAA Amendments.

[492] H.R. Rep. No. 95–294 (May 12, 1977), 1977 CAA Legis. Hist. at 2662 (emphasis added). Congress also endorsed the EPA's practice of establishing ''emission guidelines'' under CAA section 111(d). *See* H.R. Rep. No. 95–294 (May 12, 1977), 1977 CAA Legis. Hist. at 2662 (''The Administrator would establish guidelines as to what the best system for each such category of existing sources is. However, the state would be responsible for determining the applicability of such guidelines to any particular source or sources.'').

[493] Sen. Muskie, S. Consideration of the H.R. Conf. Rep. No. 95–564 (Aug. 4, 1977), 1977 CAA Legis. Hist. at 353.

[494] In 1977, Congress added a new substantive definition for ''emission standard'' generally applicable throughout the CAA. 1977 CAA Amendments, Public Law 95–95, § 301, 91 Stat. 685, 770 (Aug. 7, 1977) (defining ''emission limitation'' and ''emission standard'' as ''a requirement established by the State or the Administrator which limits the quantity, rate, or concentration of emissions of air pollutants on a continuous basis, including any requirement relating to the operation or maintenance of a source to assure continuous emission reduction.''). Congress also added a generally applicable definition of standard of performance, defined as ''a requirement of continuous emission reduction, including any requirement relating to the operation or maintenance of a source to assure continuous emission reduction.'' *Id.*

[495] We note that the general definition of a standard of performance at CAA section 302(l) still uses ''continuous.'' Even if this provision applies to section 111, it does not affect our analysis in this rule, including our interpretation that BSER includes building blocks 2 and 3.

[496] There are numerous reasons to find that particular CAA section 111(b) standards of performance should be based on controls installed at the source at the time of new construction. This is due in part to the recognition that new sources have long operating lives over which initial capital costs can be amortized, as recognized in the legislative history for section 111. Thus, new construction is the preferred time to drive capital investment in emission controls. *See, e.g.,* S. Rep. No. 91–1196, at 15–16, 1970 CAA Legis. Hist. at 416 (''[t]he overriding purpose of this section [concerning new source performance standards] 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.''); *see also* 1977 CAA Amendments, § 109, 91 Stat. at 700, (redefining, with respect to new sources, CAA section 111(a)(1) to reflect the best ''technological system of continuous emission reduction'' and adding CAA section 111(a)(7) to define this new term). However, as a result of the 1990 revisions to CAA section 111(a)(1), which replaced the phrase ''technological system of continuous emission reduction'' with ''system of emission reduction,'' new source standards would not be restricted to being based on technological control measures.

[497] *See, e.g.,* comments by UARG at 31 (the building blocks other than building block 1 take a '' 'beyond-the-source' approach'' and ''impermissibly rely on measures that go beyond the boundaries of individual affected EGUs and that are not within the control of individual EGU owners and operators''); comments by American Chemistry Council *et al.* (''Associations'') at 60–61 (EPA's proposed BSER analysis is unlawful because it ''looks beyond the fence line of the fossil fuel-fired EGUs that are the subject of this rulemaking;'' ''the standard of performance must . . . be limited to the types of actions that can be implemented directly by an existing source within [the appropriate] class or category.'').

[498] 1977 CAA Amendments, § 109, 91 Stat. at 700; *see also* CAA section 111(a)(7).

[499] H.R. Rep. No. 95–294 (May 12, 1977), 1977 CAA Legis. Hist. at 2655 (emphasis added). Generally speaking, coal cleaning activities also are conducted by third parties. For instance, EPA

Continued

Thus, the standard of performance reflecting the best technological system implementable by an affected source could be based, in part, on technologies used at off-site facilities owned and operated by third-parties.

In the 1990 CAA Amendments, Congress eliminated many of the restrictions and other provisions added in the 1977 CAA Amendments by largely reinstating the 1970 CAA Amendments' definition of ''standard of performance.'' Nevertheless, there is no indication that in doing so, Congress intended to preclude the EPA from considering coal cleaning by third parties (which had been considered within the scope of the best system of emission reduction even under the 1970 CAA Amendments),[500] and in fact, the EPA's regulations promulgated after the 1990 CAA Amendments continue to impose standards of performance that are based on third-party coal cleaning.[501]

(c) *Consistency of a broad interpretation of CAA section 111 with the overall structure of the CAA.*

Interpreting CAA section 111(d)(1) and (a)(1) to authorize the EPA's consideration of the building block 2 and 3 measures is consistent with the overall structure of the CAA, particularly as it was amended in 1970, when Congress added CAA section 111 in much the same form that it reads today.

In the 1970 CAA Amendments, for the most part, and particularly for stationary source provisions, Congress painted with broad brush strokes, giving broad authority to the EPA or the states. That is, Congress established general requirements that were intended to produce stringent results, but gave the EPA or the states great discretion in fashioning the types of measures to achieve those results.

For example, under CAA section 109, Congress authorized the EPA to promulgate national ambient air quality standards (NAAQS) for air pollutants, and Congress established general criteria and procedural requirements, but left to the EPA discretion to identify the air pollutants and select the standards. Under CAA section 110, Congress required the states to submit to the EPA SIPs, required that the plans attain the NAAQS by a date certain, and established procedural requirements, but allowed the states broad discretion in determining the substantive requirements of the SIPs.

Under CAA section 111(b), Congress directed the EPA to list source categories that endanger public health or welfare and established procedural requirements, but did not include other substantive requirements, and instead gave the EPA broad discretion to determine the criteria for endangerment.

Under CAA section 112, Congress required the EPA to regulate certain air pollutants and to set ''emission standards'' that meet general criteria, and established procedural requirements, but did not include other substantive requirements and, instead, gave the EPA broad discretion in identifying the types of pollutants and in determining the standards.[502] By and large, Congress left these provisions intact in the 1977 CAA Amendments.[503] [504]

Congress drafted the CAA section 111(d) requirements in the 1970 CAA Amendments, and revised them in the 1977 CAA Amendments, in a manner that is similar to the other stationary source requirements, just described, in CAA sections 109, 110, 111(b), and 112. The CAA section 111(d) requirements are broadly phrased, include procedural requirements but no more than very general substantive requirements, and give broad discretion to the EPA to determine the basis for the required emission limits and to the states to set the standards. It should be noted that this drafting approach is not unique to the CAA; on the contrary, Congress ''usually does not legislate by specifying examples, but by identifying broad and general principles that must be applied to particular factual instances.'' [505]

In light of this statutory framework, it is clear that Congress delegated to the EPA the authority to administer CAA section 111, including by authorizing the EPA to apply the ''broad and general principles'' contained in CAA section 111(a)(1) to the particular circumstances we face today.

(3) *Comments and responses.*

While some commenters support the EPA's interpretation of section 111 to authorize the inclusion of building blocks 2 and 3 in the BSER, other commenters assert that the emission standards must be based on measures that the sources subject to CAA section 111—in this rule, the affected EGUs—apply to their own design or operations, and, as a result, in this rule, cannot include measures implemented at entities other than the affected EGUs that have the effect of reducing generation, and therefore emissions, from the affected EGUs. The commenters assert that various provisions in CAA section 111 make this limitation clear. We do not find those arguments persuasive.

First, some commenters state that under CAA section 111(d)(1) and (a)(1), the existing sources subject to the standards of performance must be able to achieve their emission limit, but that they are able to do so only through measures integrated into the source's own design and operation. As a result, according to these commenters, those are the only types of measures that may qualify as a ''system of emission reduction'' that may form the basis of the emissions standards. We disagree. We see nothing in CAA section 111(d)(1) or (a)(1) which by its terms limits CAA section 111 to measures that must be integrated into the sources' own design or operation. Rather, we recognize that in order for an emission limitation based on the BSER to be ''achievable,'' the BSER must consist of measures that can be undertaken by an affected source—that is, its owner or operator. As noted elsewhere in the

recognized in a regulatory analysis of new source performance standards for industrial-commercial-institutional steam generating units that the technology ''requires too much space and is too expensive to be employed at individual industrial-commercial-institutional steam generating units.'' U.S. EPA, *Summary of Regulatory Analysis for New Source Performance Standards: Industrial-Commercial-Institutional Steam Generating Units of Greater than 100 Million Btu/hr Heat Input,* EPA–450/3–86–005, p. 4–4 (June 1986).

[500] *See* U.S. EPA, *Background Information for Proposed New-Source Performance Standards: Steam Generators, Incinerators, Portland Cement Plants, Nitric Acid Plants, Sulfuric Acid Plants,* Office of Air Programs Tech. Rep. No. APTD–0711, p. 7 (Aug. 1971) (indicating the ''desirability of setting sulfur dioxide standards that would allow the use of low-sulfur fuels *as well as fuel cleaning,* stack-gas cleaning, and equipment modifications'' (emphasis added)).

[501] 40 CFR 60.49b(n)(4); see also *Amendments to New Source Performance Standards (NSPS) for Electric Utility Steam Generating Units and Industrial-Commercial-Institutional Steam Generating Units; Final Rule,* 72 FR 32742 (June 13, 2007).

[502] By comparison, under the 1990 CAA Amendments, Congress substantially transformed CAA section 112 to be significantly more prescriptive in directing EPA rulemaking, which reflected Congress's increased knowledge of hazardous air pollutants and impatience with the EPA's progress in regulating.

[503] In the 1977 CAA Amendments, Congress applied the same broad drafting approach to the stratospheric ozone provisions it adopted in CAA sections 150–159. There, Congress authorized the EPA to determine whether, ''in the Administrator's judgment, any substance, practice, process, or activity may reasonably be anticipated to affect the stratosphere, especially ozone in the stratosphere, and such effect may reasonably be anticipated to endanger public health or welfare,'' and then directed the EPA, if it made such a determination, to ''promulgate regulations respecting the control of such process practice, process, or activity. . . .'' CAA section 157(a). This provision does not further specify requirements for the regulations.

[504] On the other hand, in those instances in which Congress had a clear idea as to the emission limitations that it thought should be imposed, it mandated those emission limits, *e.g.,* in Title II concerning motor vehicles.

[505] *Pub. Citizen* v. *U.S. Dept. of Justice,* 491 U.S. 440, 475 (1989) (Kennedy, J., concurring).

preamble, the affected sources subject to this rule are fully able to meet their emission standards by undertaking the measures described in all three building blocks. Moreover, as discussed, the measures in building blocks 2 and 3 are highly effective in achieving CO_2 emission reductions from these affected EGUs, given the unique characteristics of the industry. This reinforces the conclusion that the term ''system of emission reduction'' is broad enough to include these measures.

The broad nature of CAA section 111(d)(1) and (a)(1) is also confirmed by comparing it to CAA provisions that explicitly require controls on the design or operations of an affected source. The most notable comparison is at CAA section 111(a)(7). The term ''technological system of continuous emission reduction,'' which was added in 1977 and remains as a separately defined term means, in part, ''a technological process *for production or operation* by any source *which is inherently* low-emitting or nonpolluting.'' (Emphasis added.) With respect to this portion of the definition (and ignoring the additional text, which includes ''precombustion cleaning or treatment of fuels'' and clearly encompasses off-site activities), it could be argued that between 1977 and 1990 new source performance standards should be restricted to measures that could be integrated into the design or operation of a source. However, commenters' assertion that the BSER must be limited in a similar fashion ignores the deliberate change in 1990 to restore the broader definition of a standard of performance (*i.e.,* that it be based on the BSER and not the TSCER). In any case, the narrower scope of CAA section 111(a)(7) was never applicable to the regulation of existing sources under CAA section 111(d).

Several other examples of standard setting in the CAA shed light on ways in which Congress has constrained the EPA's review. CAA section 407(b)(2) provides that the EPA base NO_X emission limits for certain types of boilers ''on the degree of reduction achievable through the *retrofit* application of the best system of continuous emission reduction.'' (Emphasis added.) Likewise, in determining best available retrofit technology under CAA section 169A, the state (or Administrator) must ''take into consideration the costs of compliance, the energy and nonair quality environmental impacts, any existing pollution control technology *in use at the source,* the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result *from the use of such technology.*'' [506] (Emphasis added.) These provisions make clear that Congress knew how to constrain the basis for emission limits to measures that are integrated into the design or operation of the affected source, and that its choice to base CAA section 111(d)(1) and (a)(1) standards of performance on a ''system of emission reduction'' indicates Congress' intent to authorize a broader basis for those standards.

Some commenters also argue that other provisions in CAA section 111 indicate that Congress intended that CAA section 111(d)(1) and (a)(1) be limited to measures that are integrated into the source's design or operations. This argument is unpersuasive for several reasons. First, it would be unreasonable to presume that Congress intended to limit the BSER, indirectly through these other provisions, to measures that are integrated into the affected source's design or operations, when Congress could have done so expressly, as it did for the above-discussed CAA section 407(b)(2) NO_X requirements.

Second, the interpretations that commenters offer for these various provisions misapply the text. For example, commenters note that under CAA section 111(d)(1), (a)(3), and (a)(6), the standards of performance apply to ''any existing source,'' and an ''existing source'' is defined to include ''any stationary source,'' which, in turn, is defined as ''any building, structure, facility, or installation which emits or may emit any air pollutant.'' Commenters assert that these applicability and definitional provisions indicate that the BSER provisions in CAA section 111(d)(1) and (a)(1) must be interpreted to require that the control measures must be integrated into the design or operations of the source itself.

We disagree. These applicability and definitional provisions are jurisdictional in nature. Their purpose is simply to identify the types of sources whose emissions are to be addressed under CAA section 111(d), *i.e.,* stationary sources, as opposed to other types of sources, *e.g.,* mobile sources, whose emissions are addressed under other CAA provisions (such as CAA Title II). This purpose is made apparent by the terms of CAA section 111(a)(3), which contains two sentences (the second of which commenters seem to ignore). The first sentence provides: ''The term 'stationary source' means any building, structure, facility, or installation which emits or may emit any air pollutant.'' The second sentence provides: ''Nothing in subchapter II of this chapter relating to nonroad engines shall be construed to apply to stationary internal combustion engines.'' This second sentence explains that stationary internal combustion engines are to be regulated under CAA section 111, and not Title II (relating to mobile sources), which confirms that the purpose of the definition of stationary source is jurisdictional in nature—to identify the emissions that are to be regulated under section 111, as opposed to other CAA provisions.

These applicability and definitional provisions say nothing about the system of emission reduction—whether it is limited to measures integrated into the design or operation of the source itself or may be broader—that may form the basis of the standards for those emissions that are to be promulgated under CAA section 111.

Third, this argument by commenters does not account for the commonsense proposition that it is the owner/operator of the stationary source, not the source itself, who is responsible for taking actions to achieve the emission rate, so that actions that the owner/operator is able to take should be considered in determining the appropriate standards for the source's emissions. Again, it is common sense that buildings, structures, facilities, and installations can take no actions—only owners and operators can install and maintain pollution control equipment; only owners and operators can solicit precombustion cleaning or treatment of fuel services; and only owners and operators can apply for a permit or trade allowances.[507] Other provisions in CAA section 111 make clear the role of the owner/operator. CAA section 111(e) provides that for new sources, the burden of compliance falls on the ''owner or operator.'' [508] The same is necessarily true for existing sources. This supports the EPA's view that the basis for whether a control measure qualifies as a ''system of emission reduction'' under CAA section 111(d)(1)

[506] Even under BART, the EPA is authorized to allow emissions trading between sources. *See, e.g.,* 40 CFR 51.308(e)(1) & (2); *Util. Air Reg. Group* v. *EPA,* 471 F.3d 1333 (D.C. Cir. 2006); *Ctr. for Econ. Dev.* v. *EPA,* 398 F.3d 653 (D.C. Cir. 2005); and *Cent. Ariz. Water Dist.* v. *EPA,* 990 F.2d 1531 (9th Cir. 1993).

[507] Industry commenters also acknowledged that it is the owner or operator that implements the control requirements. See UARG comment at 19 (section 111(d) ''provides for the regulation of individual emission sources through performance standards that are based on what design or process changes an individual source's owner can integrate into its facility'').

[508] CAA section 111(e) provides: (''[I]t shall be unlawful for any owner or operator of any new source to operate such source in violation of any [applicable] standard of performance.'')

and (a)(1) is whether it is something that the owner/operator can implement in order to achieve the emissions standard assigned to the source—if so, the control measure should qualify as a ''system of emission reduction''—and not whether the control measure is integrated into the source's own design or operation.

Commenters also argue that CAA section 111(h), which authorizes ''design, equipment, work practice or operational standard[s]'' (together, ''design standards'') only when a source's emissions are not emitted through a conveyance or cannot be measured, makes clear that CAA section 111 standards of performance must be based on measures integrated into a source's own design or operations. We disagree. CAA section 111(h) concerns the relatively rare situation in which an emission standard, which entails a numerical limit on emissions, *is not* appropriate because emissions cannot be measured, due either to the nature of the pollutant (*i.e.,* the pollutant is not emitted through a conveyance) or the nature of the source category (*i.e.,* the source category is not able to conduct measurements). CAA section 111(h) provides that in such cases, the EPA may instead impose design standards rather than establish an emission standard (*i.e.,* the EPA can require sources to implement a particular design, equipment, work practice, or operational standard). When an emissions standard *is* appropriate, as in the present rule, CAA section 111(h) is silent as to what types of measures—whether limited to a source's own design or operations—may be considered as the system of emission reduction.[509] In any event, CAA section 111(h) applies only to standards promulgated by the Administrator, and therefore appears by its terms to be limited to CAA section 111(b) rulemakings for new, modified, or reconstructed sources, not CAA section 111(d) rulemakings for existing sources.

Some commenters identify other provisions of CAA section 111 that, in their view, prove that CAA section 111 is limited to control measures that are integrated within the design or operations of the source. We do not find those arguments persuasive, for the reasons discussed in the supporting documents for this rule.

Commenters also argue, more generally, that Congress knew how to authorize control measures such as RE, as indicated by Congress's inclusion of those measures in Title IV (relating to acid rain), so the fact that Congress did not explicitly include these measures in the BSER provisions of CAA section 111(d)(1) and (a)(1) indicates that Congress did not intend that they be included as part of the BSER, and instead intended that the BSER be limited to measures integrated into the sources' design or operations. This argument misses the mark. The provisions of CAA section 111(d)(1) and (a)(1) do not explicitly include *any* specific emission reduction measures—neither RE measures (like the ones Congress wanted to incentivize under Title IV), nor measures that are integrated into the sources' design or operations (like the retrofit control measures Congress required under CAA section 407(b)). But this contrast with other CAA provisions does not mean that Congress did not intend the BSER to include any of those types of measures. Rather, this contrast supports viewing a ''system of emission reduction'' under CAA section 111 as sufficiently broad to encompass a wide range of measures for the purpose of emission reduction of a wide range of pollutants from a wide range of stationary sources.[510]

c. *Deference to interpret the BSER to include building blocks 2 and 3.*

To the extent that it is not clear whether the phrase ''system of emission reduction'' may include the measures in building blocks 2 and 3, the EPA's interpretation of CAA section 111(d) and (a) is reasonable[511] in light of our discretion to determine ''whether *and how* to regulate carbon-dioxide emissions from power plants . . . .''[512]

Our interpretation that a ''system of emission reduction'' for the affected EGUs may include building blocks 2 and 3 is a reasonable construction of the statute for the reasons described above and in this section below.

(1) *Consistency of building blocks 2 and 3 with the structure of the utility power sector.*

(a) *Integration of the utility power sector.*

Certain characteristics of the utility power sector are of central importance for understanding why the measures of building blocks 2 and 3 qualify as part of the system of emission reduction. As discussed above, electricity is highly substitutable and the utility power sector is highly integrated, so much so that it has been likened to a ''complex machine.''[513] Specifically, the utility power sector is characterized by physical, as well as operational, interconnections between electricity generators themselves, and between those generators and electricity users. Because of the physical properties of electricity and the current low availability of large scale electricity storage, generation and load (or use) must be instantaneously balanced in real time. As a result, the utility power sector is uniquely characterized by extensive planning and highly coordinated operation. These features have been present for decades, and in fact, over time, the sector has become more highly integrated. Another important characteristics of the utility power sector is that although the states have developed both regulated and de-regulated markets, the generation of electricity reflects a least-cost dispatch approach, under which electricity is generated first by the generators with the lowest variable cost.

These characteristics of the sector have facilitated the overall objective of providing reliable electric service at least cost subject to a variety of constraints, including environmental constraints. Moreover, in each type of market, the sector has developed mechanisms, including the participation of institutional actors, to safeguard reliability and to assure least cost service.

Congress,[514] the Courts,[515] the EPA in its regulatory actions,[516] and states in

[509] For this same reason, the fact that CAA section 111(h) authorizes the EPA to impose certain types of standards—such as, among others, work practice or operational standards—only in limited circumstances not present in this rulemaking, does not mean that the EPA cannot consider those same measures as the BSER in promulgating a standard of performance.

[510] It should also be noted that Title IV is limited to particular pollutants (*i.e.,* SO_2 and NO_X) and particular sources—fossil fuel-fired EGUs—and as a result, lends itself to greater specificity about the types of control measures. Section 111(d), in contrast, applies to a wide range of source types, which, as discussed above, supports reading it to authorize a broad range of control measures.

[511] *EPA* v. *EME Homer City Generation, L.P.,* 134 S. Ct. 1584, 1603 (2014) (''We routinely accord dispositive effect to an agency's reasonable interpretation of ambiguous statutory language.'').

[512] *American Electric Power Co.* v. *Connecticut,* 131 S. Ct. 2527, 2538 (2011) (''*AEP*'') (emphasis added).

[513] S. Massoud Amin, ''Securing the Electricity Grid,'' The Bridge, Spring 2010, at 13, 14; Phillip F. Schewe, The Grid: A Journey Through the Heart of Our Electrified World 1 (2007).

[514] *See* CAA section 404(f)(2)(B)(iii)(I) (conditioning a utility's eligibility for certain allowances on implementing an energy conservation and electric power plan that evaluates a range of resources to meet expected future demand at least cost); *see also* S. Rep. No. 101–228, at 319–20 (Dec. 20, 1989) (recognizing that ''utilities already engage in power-pooling arrangements to ensure maximum flexibility and efficiency in supplying power'' to support the establishment of an allowance system under Title IV).

[515] *New York* v. *Federal Energy Regulatory Commission,* 535 U.S. 1, at 7 (2002) (citing Brief for Respondent FERC 4–5).

[516] ''Stack Heights Emissions Balancing Policy,'' 53 FR 480, 482 (Jan. 7, 1988).

their regulatory actions [517] have recognized the integrated nature of the utility power sector.

(b) *Significance of integrated utility power sector for the BSER.*

The fungibility of electricity, coupled with the integration of the utility power sector, means that, assuming that demand is held constant, adding electricity to the grid from one generator will result in the instantaneous reduction in generation from other generators. Similarly, reductions in generation from one generator lead to the instantaneous increase in generation from other generators. Thus, the operation of individual EGUs is integrated and coordinated with the operations of other EGUs and other sources of generation, as well as with electricity users. This allows for locational flexibility across the sector in meeting demand for electricity services. The institutions that coordinate planning and operations routinely use this flexibility to meet demand for electricity services economically while satisfying constraints, including environmental constraints. Because of these characteristics, EGU owner/operators have long conducted their business, including entering into commercial arrangements with third parties, based on the premise that the performance and operations of any of their facilities is substantially dependent on the performance and operation of other facilities, including ones they neither own nor operate. For example, when an EGU goes off-line to perform maintenance, its customer base is served by other EGUs that increase their generation. Similarly, if an EGU needs to assure that it can meet its obligations to supply a certain amount of generation, it may enter into arrangements to purchase that generation, if it needs to, from other EGUs.

Because of this structure, fossil fuel-fired EGUs can reduce their emissions by taking the actions in building blocks 2 and 3. Specifically, fossil fuel-fired EGUs may generate or cause the generation of increased amounts of lower- or zero-emitting electricity—through contractual arrangements, investment, or purchase—which will back out higher-emitting generation, and thereby lower emissions. In addition, fossil fuel-fired EGUs may reduce their generation, which, given the overall emission limits this rule requires, will have the effect of stimulating lower- or zero-emitting generation.

It should also be noted that CO_2 is particularly well-suited for building blocks 2 and 3 because it is a global, not local, air pollutant, so that the location where it is emitted does not affect its environmental impact. The U.S. Supreme Court in the *UARG* case highlighted the importance of taking account of the unique characteristics of CO_2.[518]

In light of these characteristics of the utility power sector, as well as the characteristics of CO_2 pollution, it is reasonable for the EPA to reject an interpretation of the term ''system of emission reduction'' that would exclude building blocks 2 and 3 from consideration in this rule and instead restrict consideration to measures integrated into each individual affected source's design or operation, especially since the record and other publicly available information makes clear that the measures in the two building blocks are effective in reducing emissions and are already widely used.

As discussed above, no such restriction on the measures that can be considered part of a ''system of emission reduction'' is required by the statutory language, and the legislative history demonstrates that Congress intended an interpretation of the phrase broad enough to encompass building blocks 2 and 3. The narrow interpretation advocated by some commenters would permit consideration only of potential CO_2 reduction measures that are either more expensive than building blocks 2 and 3 (such as the use of natural gas co-firing at affected EGUs or the application of CCS technology) or measures capable of achieving far less reduction in CO_2 emissions (such as the heat rate improvement measures included in building block 1). Imposing such a restrictive interpretation—one which is not called for by the statute—would be inconsistent with CAA section 111's specific requirement that standards be based on the ''best'' system of emission reduction and, as discussed below, would be inconsistent with Congressional design that the CAA be comprehensive and address the major environmental issues.[519]

The unique characteristics of the sector described above require coordinated action in the fundamental, primary function of EGUs—and in meeting current pollution control requirements to the extent that EGUs operate in dispatch systems that apply variable costs in determining dispatch—and affected EGUs necessarily already plan and operate on a multi-unit basis. In doing so, they already make use of building blocks 2 and 3 to meet operational and environmental objectives in a cost-effective manner, as further described below. CO_2 is a global pollutant that is exceptionally well-suited to emission reduction efforts optimized on a broad geographic scale rather than on a unit-by-unit basis. It is also clear from both comments and communications received through the Agency's outreach efforts that affected EGUs will seek to use building blocks 2 and 3 to achieve compliance with the emission standards set in the section 111(d) plans following promulgation of this rule. For these reasons—and the additional reasons discussed below—interpreting ''system of emission reduction'' so as to allow consideration in this rule of only the individual pieces of the ''complex machine,'' and to forbid consideration of the ways in which the pieces actually fit and work together as parts of that machine, such as building blocks 2 and 3, cannot be justified. This is particularly so in light of the dilemma presented by the types of control options that commenters argue are the only ones authorized under section 111(a)(1), which are controls that apply to the design or operation of the affected EGUs themselves. On the one hand, the control measures in building block 1 yield only a small amount of emission reductions. On the other hand, control measures such as carbon capture and storage, or co-firing with natural gas, could yield much greater emission reductions, but are substantially more expensive than building blocks 2 and 3.

(2) *Current implementation of measures in building blocks 2 and 3.*

The requirement that the ''system of emission reduction'' be ''adequately demonstrated'' suggests that we begin our review under CAA section 111(d)(1) and (a)(1) with the systems that sources are already implementing to reduce their emissions. As noted above, fossil fuel-fired EGUs have long implemented, and are continuing to implement, the measures in building blocks 2 and 3 for various purposes, including for the purpose of reducing CO_2 emissions [520]—

[517] See 79 FR 34830, 34880 (June 18, 2014) (discussing State of California Global Warming Solutions Act of 2006, Assembly Bill 32, *http://www.leginfo.ca.gov/pub/05-06/bill/asm/ab_0001-0050/ab_32_bill_20060927_chaptered.pdf*, and quoting December 27, 2013 Letter from Mary D. Nichols, Chairman of California Air Resources Board, to EPA Administrator Gina McCarthy).

[518] *See Util. Air. Reg. Group* v. *EPA,* 134 S. Ct. 2427, 2441 (2014).

[519] *See King* v. *Burwell,* No. 14–114 (2015) (slip op., at 21) (''But in every case we must respect the role of the Legislature, and take care not to undo what it has done.'').

[520] A number of utilities have climate mitigation plans. Examples include National Grid, *http://www2.nationalgrid.com/responsibility/how-were-doing/grid-data-centre/climate-change/;* Exelon, *http://www.exeloncorp.com/newsroom/pr_20140423_EXC_Exelon2020.aspx;* PG&E, *http://*

Continued

and certainly always with the effect of reducing emissions. This is a strong indicator that these measures should be considered part of a ''system of emission reduction'' for CO_2 emissions from these sources. The requirement that the ''system of emission reduction'' be ''adequately demonstrated'' indicates that the implementation of control mechanisms or other actions that the sources are already taking to reduce their emissions are of particular relevance in establishing the emission reduction requirements of CAA section 111(d)(1) and (a)(1). As a result, such measures are a logical starting point for consideration as a ''system of emission reduction'' under CAA section 111.

(3) *Reliance in CAA Title IV on building block measures.*

Some of the building block approaches to reducing emissions in the utility power sector were first tested around the time that Congress adopted the 1970 CAA Amendments.[521] Over time, these techniques have become more established within the industry, and by the 1990 CAA Amendments, Congress based the Title IV acid rain program for existing fossil fuel-fired EGUs in part on the same measures that are considered here.

(a) *Overview.*

It is logical that in determining whether the ''system of emission reduction'' that Congress established in CAA section 111(d)(1) and (a)(1) is broad enough to include the measures in building blocks 2 and 3 as the basis for establishing emission guidelines for fossil fuel-fired EGUs, an inquiry should be made into the tools that Congress relied on in other CAA provisions to reduce emissions from those same sources. The most useful CAA provision to examine for this purpose is Title IV, which includes a nationwide cap-and-trade program under which coal-fired power plants must have allowances for their SO_2 emissions.

Title IV includes several signals that it is especially relevant for interpreting and implementing CAA section 111(d) for purposes of this rule. Title IV applies to most of the same sources that this rule applies to—existing coal-fired EGUs and other utility boilers, as well as NGCC units. In addition, Congress added Title IV in the 1990 CAA Amendments at the same time that Congress largely reinstated the 1970-vintage reading of section 111(a)(1) to adopt the currently applicable definition of a ''standard of performance,'' which is based on the ''best system of emission reduction . . . adequately demonstrated.'' Moreover, Congress linked Title IV and CAA section 111 in certain respects. Specifically, Congress conditioned the revisions to CAA section 111(a)(1), *i.e.,* eliminating the percentage reduction and most of the other limitations under the 1977 CAA Amendments, on the continued applicability of the Title IV SO_2 cap, so that if the cap were eliminated, the changes would, by operation of law, also be eliminated, and the 1977 version of section 111(a)(1) would be reinstated.[522] Additionally, Congress authorized the EPA to establish standards of performance for new *and* existing industrial (non-EGU) sources of SO_2 emissions if emissions from these sources might exceed 1985 levels and failed to decline at the expected rate.[523] While industrial sources were not required to participate under Title IV—they could elect to do so, under CAA section 410(a)—Congress believed SO_2 reductions from these sources were ''an essential component of the reductions sought under [Title IV]'' and intended that Title IV would ''assure[ ] that these projected reductions occur and will not be overcome by future growth in emissions.''[524] As such, Congress viewed federal standards of performance as the appropriate backstop to Title IV even for sources that could not otherwise be regulated under CAA section 111(d).[525] Together, these signals suggest that it is reasonable for the EPA to consider Title IV when interpreting and implementing CAA section 111.

For present purposes, the essential features of Title IV are that it regulates SO_2 emissions from coal-fired EGUs by adopting a nationwide cap of 8.95 million tons to be achieved through a tradable allowance system. As we explain below, the provisions of Title IV and its legislative history make clear that Congress based the stringency of the emission limitation requirement (8.95 million tons) and the overall structure of the approach (a cap-and-trade system) on Congress's recognition that the affected EGUs had a set of tools available to them to reduce their emissions, including through a shift to lower emitting generation and use of RE, along with add-on controls and other measures. Thus, Title IV provides a close analogy to CAA section 111: Generation shift and RE were part of Congress's basis for the Title IV emission requirements, and that is analogous to building blocks 2 and 3 serving as part of the ''system of emission reduction'' that is the EPA's basis for the section 111(d) emission guidelines. For this reason, the fact that in Title IV, Congress relied on generation shift and RE as the basis for the SO_2 emission limitations for affected EGUs strongly supports interpreting CAA section 111(d)(1) and (a)(1) to include use of those same measures as part of the ''system of emission reduction'' as the basis for CO_2 emission limitations for those same sources.

(b) *Title IV provisions.*

Several provisions of Title IV make explicit Congress's reliance on some of the same measures as are in building blocks 2 and 3. Title IV begins with a statement of congressional ''findings,'' including the finding that ''strategies and technologies for the control of precursors to acid deposition exist now that are economically feasible, and improved methods are expected to become increasingly available over the next decade.'' CAA section 401(a)(4) (emphasis added). Title IV then identifies as its ''purposes,'' ''to reduce the adverse effects of acid deposition through reductions in annual emissions of sulfur dioxide . . . and nitrogen oxides,'' as well as ''to encourage energy conservation, use of renewable and clean alternative technologies, and pollution prevention as a long-range strategy, consistent with the provisions of this subchapter, for reducing air pollution and other adverse impacts of energy production and use.'' CAA section 401(b) (emphasis added).

By its terms, this statement of Title IV's purposes explicitly embraces the use of RE. Moreover, the legislative

www.pge.com/about/environment/pge/climate/; and Austin Energy, *http://austinenergy.com/wps/portal/ae/about/environment/austin-climate-protection-plan/!ut/p/a0/04_Sj9CPykssy0xPLMnMz0vMAfGjzOINjCyMPJwNjDzdzY0sDBzdnZ28TcP8DAMMDPQLsh0VAU4fG7s!/.*

[521] *See, e.g.,* Shepard, Donald S., *A Load Shifting Model for Air Pollution Control in the Electric Power Industry,* Journal of the Air Pollution Control Association, Vol. 20:11, pp. 756–761 (November 1970).

[522] 1990 CAA Amendments, § 403, 104 Stat. at 2631 (requiring repeal of amendments to CAA section 111(a)(1) upon any cessation of effectiveness of CAA section 403(e), which requires new units to hold allowances for each ton of SO_2 emitted). Congress believed that mandating a technological standard through the percentage reduction requirement in section 111(a)(1) would ensure the continued availability of low sulfur coal for existing sources. In other words, the percentage reduction requirement discouraged compliance with new source performance standards based solely on fuel shifting because it was much more costly to achieve the percentage reduction with lower sulfur coal. This belief was expressed during the 1977 CAA Amendments and is discussed above as part of the legislative history of section 111.

[523] 1990 CAA Amendments, § 406, 104 Stat. at 2632–33; *see also* S. Rep. No. 101–228, at 282 (industrial source emissions totaled 5.6 million tons of SO_2 in 1985).

[524] S. Rep. No. 101–228, at 345 (Dec. 20, 1989).

[525] To reiterate, ordinarily, standards of performance cannot be used to regulate SO_2 emissions from existing sources because of the pollutant exclusions in CAA section 111(d).

history makes clear that the reference in the ''findings'' section quoted above to ''strategies and technologies'' includes generation shift to lower-emitting generation. Specifically, the Senate Report stated that an ''allowance system'' [526] would encourage such ''technologies and strategies'' as

> energy efficiency; enhanced emissions reduction or control technologies—like sorbent injection, cofiring with natural gas, integrated gasification combined cycles; fuel-switching and *least-emissions dispatching* in order to maximize emissions reductions. [527]

Congress's reliance on generation shifting and RE to reduce acid rain precursors from affected EGUs in Title IV strongly supports the EPA's authority to identify those same measures as part of the CAA section 111 ''system of emission reduction'' to reduce CO_2 emissions from those same sources.

In addition, Title IV includes other provisions expressly concerning RE. In CAA section 404(f) and (g), Congress set aside a special pool of allowances to encourage use of RE. In order to obtain a special allowance (which would authorize emissions from a coal-fired utility), an electric utility needed to pay for qualifying RE sources ''directly or through purchase from another person.'' [528] These measures confirm Congress's recognition that RE was available to the industry, was desirable to encourage from a policy perspective, and was appropriate to consider in determining the amount of pollution reduction the law should require.

(c) *Title IV legislative history.*

Numerous statements in the legislative history confirm that Congress based the Title IV requirements on the fact that affected EGUs could reduce their SO_2 emissions through a set of measures, including shifting to lower-emitting generation as well as reliance on RE.

For example, the Senate Committee Report [529] and Senator Baucus,[530] a member of the Senate Committee on Environment and Public Works and Chairman of the House and Senate Clean Air Conferees, both emphasized that affected EGUs could rely on, among other things, ''least-emissions dispatching in order to maximize emissions reductions.'' Similarly, statements supporting the RE reserve were included in the legislative history on the House side.

> We believe that this provision of the bill will establish a balanced and workable approach that will provide certainty for utility companies that are considering conservation and renewables, while at the same time strengthening the environmental goals of this legislation.[531]

(4) *Reliance on RE measures to reduce CO_2.*

The Title IV legislative history also makes clear that Congress viewed RE measures as a means to reduce CO_2 for the purpose of mitigating climate change. By the time of the 1990 CAA Amendments, Congress had long been aware that emissions of CO_2 and other GHGs put upward pressure on world temperatures and threatened to change the climate in destructive ways. In 1967, President Lyndon Johnson sent a letter to Congress recognizing that carbon dioxide was changing the composition of the atmosphere.[532] The record for the 1970 CAA Amendments include hearings [533] and a report by the National Academy of Sciences noting that carbon dioxide emissions could heat the atmosphere.[534] A 1976 report noting the phenomenon was included in the record for the 1977 CAA Amendments.[535] A 1977 Report by the National Academy of Sciences warned that average temperatures would rise due to the burning of fossil fuel.[536] By the time of the 1990 CAA Amendments, the dangers had become more clearly evident. Senate hearings beginning in 1988 had presented testimony from Dr. James E. Hansen of the National Aeronautics and Space Administration and other scientists that described the dangers of climate change caused by anthropogenic carbon dioxide and other GHG emissions and asserted that as a result of those emissions, the climate was in fact already changing.[537]

In enacting the 1990 CAA Amendments, Congress identified reductions in carbon dioxide emissions as an important co-benefit of the reductions in coal use and stressed that the RE measures would achieve those reductions. Senator Fowler, the author of the provision that established a RE technology reserve within the allowance system, noted that RE technologies, ''can greatly reduce emissions of . . . global warming gases. That makes them a potent weapon against catastrophic climate change . . . .'' [538]

In addition, the 1990 CAA Amendments required EGUs covered by the monitoring requirements of the Title IV acid rain program to report their CO_2 emissions.[539]

---

[526] *See* S. Rep. No. 101–228, at 320 (Dec. 20, 1989).

[527] *See* S. Rep. No. 101–228, at 316 (Dec. 20, 1989) (emphasis added).

[528] CAA section 404(f)(2)(B)(i).

[529] S. Rep. No. 101–228 (Dec. 20, 1989), 1990 CAA Legis. Hist. at 8656.

[530] S. Debates on Conf. Rep. to accompany S. 1630, H.R. Rep. No. 101–952 (Oct. 27, 1990), 1990 CAA Legis. Hist. at 1033–35 (statement of Senator Baucus, inserting ''the Clean Air Conference Report'' into the record).

[531] H.R. Rep. No. 101–490, at 368–69; 674–76 (May 17, 1990) (additional views of Reps. Markey and Moorhead) (''We believe that H.R. 3030, as amended, will create a strong and effective incentive for utilities to immediately pursue energy conservation and renewable energy sources as key components of their acid rain control strategies.''); *see also* Rep. Collins, H. Debates on H.R. Conf. Rep. No. 101–952 (Oct. 26, 1990), 1990 CAA Legis. Hist. at 1307 (''The bottom line is that our Nation's utilities and production facilities must reach beyond coal, oil, and fossil fuels. The focus must shift instead toward conservation and renewables such as hydropower, solar thermal, photovoltaics, geothermal, and wind. These clean sources and energy, available in virtually limitless supply, are the way of the future.'').

[532] ''Special Message to the Congress on Conservation and Restoration of Natural Beauty (Feb. 8, 1965). *http://www.presidency.ucsb.edu/ws/?pid=27285* (''This generation has altered the composition of the atmosphere on a global scale through radioactive materials and a steady increase in carbon dioxide from the burning of fossil fuels.'').

[533] Testimony of Charles Johnson, Jr., Administrator of the Consumer Protection and Environmental Health Service (Administration Testimony), Hearing of the House Subcommittee on Public Health and Welfare (Mar. 16, 1970), 1970 CAA Legis. Hist. at 1381 (stating that ''the carbon dioxide balance might result in the heating up of the atmosphere whereas the reduction of the radiant energy through particulate matter released to the atmosphere might cause reduction in radiation that reaches the earth'').

[534] 1970 CAA Legis. Hist. at 244, 257 S. Debate on S. 4358 (Sept. 21, 1970) (statement of Sen. Boggs) (replicating Chapter IV of the Council on Environmental Quality's first annual report, which states, ''the addition of particulates and carbon dioxide in the atmosphere could have dramatic and long-term effects on world climate.'').

[535] 122 Cong. Rec. S25194 (daily ed. Aug. 3, 1976) (statement of Sen. Bumpers) (inserting into the record, ''Summary of Statements Received from Professional Societies for the Hearings on Effects of Chronic Pollution (in the Subcommittee on the Environment and the Atmosphere),'' which stated, ''there is near unanimity that carbon dioxide concentrations in the atmosphere are increasing rapidly. Though even the direction (warming or cooling) of the climate change to be caused by this is unknown, very profound changes in the balance of climate factors that determine temperature and rainfall on the earth are almost certain within 100 years'').

[536] National Academy of Sciences, ''Energy and Climate: Studies in Geophysics'' viii (1977), *http://www.nap.edu/openbook.php?record_id=12024* (noting that a fourfold to eightfold increase in carbon dioxide by the latter part of the twenty-second century would increase average world temperature by more than 6 degrees Celsius).

[537] S. Rep. No. 101–228, at 322 (Dec. 20, 1989), at 1990 Legis. Hist. at 8662 (''In the last several years, the Committee has received extensive scientific testimony that increases in the human-caused emissions of carbon dioxide and other GHGs will lead to catastrophic shocks in the global climate system.''); History, Jurisdiction, and a Summary of Activities of the Committee on Energy and Natural Resources During the 100th Congress, S. Rep. No. 101–138, at 5 (Sept. 1989); ''Global Warming Has Begun, Expert Tells Senate,'' New York Times, June 24, 1988, *http://www.nytimes.com/1988/06/24/us/global-warming-has-begun-expert-tells-senate.html.*

[538] Sen. Fowler, S. Debate on S. 1630 (Apr. 3, 1990), 1990 CAA Legis. Hist. at 7106.

[539] 1990 CAA Amendments, § 821, 104 Stat. at 2699.

(5) *Other EPA actions that rely on the building block measures.*

Another indication that it is reasonable to interpret the CAA section 111(d)(1) and (a)(1) provisions for the BSER to include the measures in building blocks 2 and 3 is that the EPA and states have relied on these measures to reduce emissions in a number of other CAA actions.

For example, in 2005, the EPA promulgated a rule to control mercury emissions from fossil fuel-fired power plants under section 111(d): The Clean Air Mercury Rule (CAMR).[540] The EPA established a nationwide cap-and-trade program that took effect in two phases: In 2010, the cap was set at 38 tons per year, and in 2018, the cap was lowered to 15 tons per year. The EPA expected, on the basis of modeling, that sources would achieve the second phase, 15-ton per year cap cost-effectively by choosing among a set of measures that included shifting generation to lower-emitting units.[541] CAMR was vacated by the D.C. Circuit on other grounds,[542] but it shows that in the only other section 111(d) rule that the EPA attempted for affected EGUs, the EPA relied on shifting generation as part of the BSER in a CAA section 111(d) rulemaking for fossil fuel-fired EGUs.

In 2011, the EPA promulgated the Cross State Air Pollution Rule (CSAPR),[543] in which it set statewide emission budgets for NO_X and SO_2 emitted by fossil fuel-fired EGUs, and based those standards in part on shifts to lower-emitting generation. CSAPR established state-wide emissions budgets based on a range of cost-effective actions that EGUs could take, and set the stringency of the deadlines for some required reductions in part because of the availability of ''increased dispatch of lower-emitting generation which can be achieved by 2012.'' [544] The EPA developed a federal implementation plan (FIP) that established a trading program to meet the state-wide emission budgets set by CSAPR. The EPA projected that sources would meet their emission reduction obligations by implementing a range of emission control approaches, including the operation of add-on controls, switches to lower-emitting coal, and ''changes in dispatch and generation shifting from higher emitting units to lower emitting units.'' [545] The U.S. Supreme Court upheld CSAPR in *EPA* v. *EME Homer City Generation, L.P.*[546]

With respect to RE, in 2004, the EPA provided guidance to states for adopting attainment SIPs under CAA section 110 that include RE measures.[547] Some states have done so. For example, Connecticut included in its SIP reductions from solar photovoltaic installations.[548] In 2012, the EPA provided additional guidance on this topic.[549] In addition, the EPA has partnered with the Northeast States for Coordinated Air Use Management (NESCAUM) and three states (Maryland, Massachusetts, and New York) to identify opportunities for including RE in a SIP and to provide real-world examples and lessons learned through those states' case studies.[550]

(6) *Other rules that relied on actions by other entities.*

The EPA has promulgated numerous actions that establish control requirements for affected sources on the basis of actions by other entities or actions other than measures integrated into the design or operations of the affected sources. This section summarizes some of those actions. First, virtually all pollution control requirements require the affected sources to depend in one way or another on other entities, such as control technology manufacturers. Second, the EPA has promulgated numerous regulatory actions that are based on trading of mass-based emission allowances or rate-based emission credits, in which many sources meet their emission limitation requirements by purchasing allowances or credits from other sources that reduce emissions.

(a) *Third-party transactions.*

To reiterate, commenters argue that the ''system of emission reduction'' must be limited to measures taken by the affected source itself because only those measures are under the control of the affected source, as opposed to third parties, and therefore only those measures can assure that the affected source will achieve its emission limits. But this argument is belied by the fact that for a wide range of pollution control measures—including many that are indisputably part of a ''system of emission reduction''—affected sources are in fact dependent on third parties. For example, to implement any type of add-on pollution control equipment that is available only from a third-party manufacturer, the affected source is dependent upon that third party for developing and constructing the necessary controls, and for offering them for sale. Indeed, the affected sources may be dependent upon third parties to install (and in some cases to operate) the controls as well, and in fact, in the CAIR rule, the EPA established the compliance date based on the limited availability of the specialized workforce needed to install the controls needed by the affected EGUs.[551] In addition, EGU owners and operators may be dependent on the actions of third parties to finance the controls and third-party regulators to assure the mechanism for repaying that financing. However, this dependence does not mean that the emission limit based on that equipment is not achievable. Rather, the fact that the owner or operator of the affected source can arrange with the various third parties to

[540] 70 FR 28606 (May 18, 2005).

[541] 70 FR 28606, 28619 (May 18, 2005) (''Under the CAMR scenario modeled by EPA, units [were] projected to meet their SO_2 and NO_X requirements and take additional steps to address the remaining [mercury] reduction requirements under CAA section 111, including adding [mercury]-specific control technologies (model applies [activated carbon injection]), additional scrubbers and [selective catalytic reduction], *dispatch changes,* and coal switching.'').

[542] *New Jersey* v. *EPA,* 517 F.3d 574, 583–84 (D.C. Cir. 2008), *cert. denied sub nom. Util. Air Reg. Group* v. *New Jersey,* 555 U.S. 1169 (2009).

[543] 76 FR 48208 (Aug. 8, 2011).

[544] 76 FR at 48452.

[545] 76 FR at 48279–80. The exact mix of controls varied for different air pollutants and different time periods, but in all cases, shifting generation from higher to lower emitting units was one of the expected control strategies for the fossil fuel-fired power plants. Prior to CSAPR, the EPA promulgated two other transport rules, the NO_X SIP Call (1998) and the Clean Air Interstate Rule (CAIR) (2005), which similarly established standards based on analysis of the availability and cost of emission reductions achievable through the use of add-on controls and generation shifting, and also authorized and encouraged the implementation of RE and demand-side EE measures. CAIR: 70 FR 25162, 25165, 25256, 25279 (May 12, 2005) (allowing use of allowance set-asides for renewables and energy efficiency); NO_X SIP Call: 63 FR 57356, 57362, 57436, 57438, 57449 (Oct. 27, 1998) (authorizing and encouraging SIPs to rely on renewables and energy efficiency to meet the state budgets).

[546] 134 S. Ct. 1584 (2014).

[547] *See, e.g.,* Guidance on SIP Credits for Emission Reductions from Electric-Sector Energy Efficiency and Renewable Energy Measures (Aug. 2004), *http://www.epa.gov/ttn/oarpg/t1/memoranda/ereseerem_gd.pdf;* Incorporating Emerging and Voluntary Measures in a State Implementation Plan (SIP) (Sept. 2004), *http://www.epa.gov/ttn/oarpg/t1/memoranda/evm_ievm_g.pdf.*

[548] CT 1997 8-hour ozone SIP Web site, *http://www.ct.gov/deep/cwp/view.asp?a=2684&q=385886&depNav_GID=1619* (see Attainment Demonstration TSD, Chapter 8 at 31, *http://www.ct.gov/deep/lib/deep/air/regulations/proposed_and_reports/section_8.pdf*).

[549] ''Roadmap for Incorporating EE/RE Policies and Programs into SIPs/TIPs'' (July 2012), *http://epa.gov/airquality/eere/manual.html.*

[550] States' Perspectives on EPA's Roadmap to Incorporate Energy Efficiency/Renewable Energy in NAAQS State Implementation Plans: Three Case Studies, Final Report to the U.S. Environmental Protection Agency (Dec. 2013), *http://www.nescaum.org/documents/nescaum-final-rept-to-epa-ee-in-naaqs-sip-roadmap-case-studies-20140522.pdf.*

[551] 70 FR 25162, 25216–25225 (May 12, 2005). The EPA noted that its view was ''based on the NO_X SIP Call experience.'' *Id.* at 25217.

acquire, install, and pay for the equipment means that emission limit is achievable.

In this rule, as noted, the affected EGUs may, in many cases, implement the measures in building blocks 2 and 3 directly, and, in other cases, implement those measures by engaging in market transactions with third parties that are as much within the affected EGUs' control as engaging in market transactions with the range of third parties involved in pollution control equipment. By the same token, the market transactions that the affected EGUs engage in with third parties to implement the measures in building blocks 2 and 3 are comparable to the market transactions that affected EGUs engage in as part of their normal course of business, which include, among many examples, transactions with RTOs/ISOs or balancing authorities, entities in organized markets.

(b) *Emissions trading.*

Additional precedent that the ''system of emission reduction'' may include the measures in building blocks 2 and 3 and is not limited to measures that a source can integrate into its own design or operations, without being dependent on other entities, is found in the many rules that Congress has enacted or that the EPA has promulgated that allow EGUs and other sources to meet their emission limits by trading with other sources. In a trading rule, the EPA authorizes a source to meet its emission limit by purchasing mass-based emission allowances or rate-based emission credits generated from other sources, typically ones that implement controls that reduce their emissions to the point where they are able to sell allowances or credits. As a result, the availability of trading reduces overall costs to the industry by focusing the controls on the particular sources that have the least cost to implement controls. For present purposes, what is relevant is that in a trading program, some affected sources choose to meet their emission limits not by implementing emission controls integrated into their own design or operations, but rather by purchasing allowances or credits. These affected sources, therefore, are dependent on the actions of other entities, which are the ones that choose to meet their emission limits by implementing emission controls, which permits them to sell allowances or credits. They are dependent, however, in the same way that a source acquiring pollution control technology for the purposes of meeting a NSPS is dependent on a vendor of that technology to fulfill its contractual obligations. That is, the source operator purchasing a credit or an allowance is acquiring an equity in the technology or action applied to the credit-selling source for purposes of achieving a reduction in emissions occurring at the selling source. Trading programs have been commonplace under the CAA, particularly for EGUs, for decades. They include the acid rain trading program in Title IV of the CAA, the trading programs in the transport rules promulgated by the EPA under the ''good neighbor provision'' of CAA section 110(a)(2)(D)(i)(I), the Clean Air Mercury Rule, and the regional haze rules. In each of these actions, the Congress or the EPA recognized that some of the affected EGUs would implement controls or take other actions that would lower their emissions and thereby allow them to sell allowances to other EGUs, which were dependent on the purchase of those allowances to meet their obligations.[552] For the reasons just described, these trading rules refute commenters' arguments for limiting the scope of the ''system of emission reduction.''

(c) *NSPS rules for EGUs that depend on the integrated grid.*

The EPA has promulgated NSPS for EGUs that include requirements based on the fact that an EGU may reduce its generation, and therefore its emissions, because the integration of the grid allows another EGU to increase generation and thereby avoid jeopardizing the supply of electricity. For example, in 1979, the EPA finalized new standards of performance to limit emissions of SO_2 from new, modified, and reconstructed EGUs. In evaluating the best system against concerns of electric service reliability, the EPA took into account the unique features of power transmission along the interconnected grid and the unique commercial relationships that rely on those features.[553]

Additionally, in 1982, the EPA recognized that utility turbines could meet a NO_X emission limit without unacceptable economic consequences because ''other electric generators on the grid can restore lost capacity caused by turbine down time.'' [554] We describe the relevant parts of these rules in greater detail in the Legal Memorandum.

(7) *Consistency with the purposes of the Clean Air Act.*

Interpreting the term ''system of emission reduction'' broadly to include building blocks 2 and 3 (so that the ''best system of emission reduction . . . adequately demonstrated'' may include those measures as long as they meet all of the applicable requirements) is also consistent with the purposes of the CAA. Most importantly, these purposes include protecting public health and welfare by comprehensively addressing air pollution, and, particularly, protecting against urgent and severe threats. In addition, these purposes include promoting pollution prevention measures, as well as the advancement of technology that reduces air pollution.

(a) *Purpose of protecting public health and welfare.*

The first provisions in the Clean Air Act set out the ''Congressional findings and declaration of purpose.'' CAA section 101. CAA section 101(a)(2) states the finding that ''the growth in the amount and complexity of air pollution brought about by urbanization, industrial development, and the increasing use of motor vehicles, has resulted in mounting dangers to the public health and welfare.'' CAA section 101(a)(3) states the finding that ''air pollution prevention (that is, the reduction or elimination, through any measures, of the amount of pollutants produced or created at the source) and air pollution control at its source is the primary responsibility of States and local governments.'' CAA section 101(a) states the finding that ''Federal financial assistance and leadership is essential for the development of cooperative Federal, State, regional, and local programs to prevent and control air pollution.''

CAA section 101(b) next states ''[t]he purposes'' of the Clean Air Act. The first purpose is ''to protect and enhance the

[552] For example, in the enacting the acid rain program under CAA Title IV, Congress explicitly recognized that some sources would comply by purchasing allowances instead of implementing controls. S. Rep. No. 101–228, at 303 (Dec. 20, 1989). Similarly, in promulgating the NO_X SIP Call in 1998, the EPA stated, ''Since EPA's determination for the core group of sources is *based on the adoption of a broad-based trading program,* average cost-effectiveness serves as an adequate measure across sources because sources with high marginal costs will be able to take advantage of this program to lower their costs.'' 63 FR at 57399 (emphasis added). By the same token, in promulgating the Cross State Air Pollution Rule, the EPA stated, ''the preferred trading remedy will allow source owners to choose among several compliance options to achieve required emission reductions in the most cost effective manner, such as installing controls, changing fuels, reducing utilization, *buying allowances,* or any combination of these actions.'' 76 FR at 48272 (emphasis added).

[553] *See* 44 FR 33580, 33597–33600 (taking into account ''the amount of power that could be purchased from neighboring interconnected utility companies'' and noting that ''[a]lmost all electric utility generating units in the United States are electrically interconnected through power transmission lines and switching stations'' and that ''load can usually be shifted to other electric generating units'').

[554] 47 FR 3767, 3768 (Jan. 27, 1982).

quality of the Nation's air resources so as to promote the public health and welfare and the productive capacity of its population.'' CAA section 101(b)(1). The second is ''to initiate and accelerate a national research and development program to achieve the prevention and control of air pollution.'' CAA section 101(b)(2). The third is ''to provide technical and financial assistance to State and local governments in connection with the development and execution of their air pollution prevention and control programs.'' CAA section 101(b)(3). The fourth is ''to encourage and assist the development and operation of regional air pollution prevention and control programs.'' CAA section 101(c) adds that ''[a] primary goal of this Act is to encourage or otherwise promote reasonable Federal, State, and local governmental actions, consistent with the provisions of this Act, for pollution prevention.''

As just quoted, these provisions are explicit that the purpose of the CAA is ''to protect and enhance the quality of the Nation's air resources so as to promote the public health and welfare and the productive capacity of its population.'' Moreover, Congress designed the CAA to be ''the comprehensive vehicle for protection of the Nation's health from air pollution'' [555] and, in fact, designed CAA section 111(d) to address air pollutants not covered under other provisions, specifically so that ''there should be no gaps in control activities pertaining to stationary source emissions that pose any significant danger to public health or welfare.'' [556] Furthermore, in these purpose provisions, Congress recognized that while pollution prevention and control are the primary responsibility of the States, ''federal leadership'' would be essential.

At its core, Congress designed the CAA to address urgent and severe threats to public health and welfare. This purpose is evident throughout 1970 CAA Amendments, which authorized stringent remedies that were necessary to address those problems. By 1970, Congress viewed the air pollution problem, which had been worsening steadily as the nation continued to industrialize and as automobile travel dramatically increased after World War II,[557] as nothing short of a national crisis.[558] With the 1970 CAA Amendments, Congress enacted a stringent response, designed to match the severity of the problem. At the same time, Congress did not foreclose the EPA's ability to address new environmental concerns; in fact, Congress largely deferred to the EPA's expertise in identifying pollutants and sources that adversely affect public health or welfare. In doing so, Congress authorized the EPA to establish national ambient air quality standards for the most pervasive air pollutants—including the precursors for the choking smog that blanketed urban areas [559]—to protect public health with an ample margin of safety. Disappointed that the states had not taken effective action to that point to curb air pollution, ''Congress reacted by taking a stick to the States'' [560] and including within the 1970 CAA Amendments both the requirement that the states develop plans to assure that their air quality areas would meet those standards by no later than five years, and the threat of imposition of federal requirements if the states did not timely adopt the requisite plans. Congress also required the EPA to establish standards for hazardous air pollutants that could result in shutting sources down. Congress added stringent controls on automobiles, overriding industry objections that the standards were not achievable. In addition, Congress added CAA section 111(b), which required the EPA to list categories based on harm to public health and regulate new sources in those categories. Congress then designed CAA section 111(d) to assure, as the Senate Committee Report for the 1970 CAA Amendments noted, that ''there should be no gaps in control activities pertaining to stationary source emissions that pose any significant danger to public health or welfare.'' [561]

Similarly, the 1977 and 1990 CAA Amendments were also designed to respond to new and/or pressing environmental issues. For example, in 1977 then-EPA Administrator Costle testified before Congress that the expected increase in coal use (in response to various energy crises, including the 1973–74 Arab Oil Embargo) ''will make vigorous and effective control even more urgent.'' [562] Similarly, by 1990, Congress recognized that ''many of the Nation's most important air pollution problems [had] failed to improve or [had] grown more serious.'' [563] Indeed, President George H. W. Bush said that '' 'progress has not come quickly enough and much remains to be done.' '' [564]

Climate change has become the nation's most important environmental problem. We are now at a critical juncture to take meaningful action to curb the growth in CO_2 emissions and forestall the impending consequences of prior inaction. CO_2 emissions from existing fossil fuel-fired power plants

[555] H.R. Rep. No. 95–294, at 42 (May 12, 1977), 1977 CAA Legis. Hist. at 2509 (discussing a provision in the House Committee bill that became CAA section 122, requiring the EPA to study and regulate radioactive air pollutants and three other air pollutants).

[556] S. Rep. No. 91–1196, at 20 (Sept. 17, 1970), 1970 CAA Legis. Hist. at 420 (discussing section 114 of the Senate Committee bill, which was the basis for CAA section 111(d)).

[557] *See* Dewey, Scott Hamilton, *Don't Breathe the Air: Air Pollution and U.S. Environmental Politics, 1945–1970* (Texas A&M University Press 2000).

[558] 1970 was a significant year in environmental legislation, but it was also marked as ''a year of environmental concern.'' Sen. Muskie, S. Debate on S. 4358 (Sept. 21, 1970), 1970 CAA Legis. Hist. at 223. By mid-1970, Congress recognized that ''[o]ver 200 million tons of contaminants [were] spilled into the air each year in America . . . . And each year these 200 million tons of pollutants endanger the health of [the American] people.'' *Id.* at 224. ''Cities up and down the east coast were living under clouds of smog and daily air pollution alerts.'' Sen. Muskie, S. Consideration of the Conference Rep. (Dec. 18, 1970), 1970 CAA Legis. Hist. at 124. Put simply, America faced an ''environmental crisis.'' Sen. Muskie, S. Debate on S. 4358 (Sept. 21, 1970), 1970 CAA Legis. Hist. at 224. The conference agreement, it was reported, ''faces the air pollution crisis with urgency and in candor. It makes hard choices, provides just remedies, requires stiff penalties.'' Sen. Muskie, S. Consideration of the Conference Rep. (Dec. 18, 1970), 1970 CAA Legis. Hist. at 123. ''[I]t represents [Congress'] best efforts to act with the knowledge available . . . in an affirmative but constructive manner.'' *Id.* at 150.

[559] *See* Dewey, Scott Hamilton, *Don't Breathe the Air: Air Pollution and U.S. Environmental Politics, 1945–1970* (Texas A&M University Press 2000) at 230 (''By the mid-1960s, top federal officials showed an increasing sense of alarm regarding the health effects of polluted air. In June, 1966, Secretary of Health, Education, and Welfare John W. Gardner testified before the Muskie subcommittee: ''We believe that air pollution at concentrations which are routinely sustained in urban areas of the United States is a health hazard to many, if not all, people.'').

[560] *Train* v. *NRDC,* 421 U.S. 60, 64 (1975).

[561] S. Rep. No. 91–1196, at 20 (Sept. 17, 1970), 1970 CAA Legis. Hist. at 420 (discussing section 114 of the Senate Committee bill, which was the basis for CAA section 111(d)). Note that in the 1977 CAA Amendments, the House Committee Report made a similar statement. H.R. Rep. No. 95–294, at 42 (May 12, 1977), 1977 CAA Legis. Hist. at 2509 (discussing a provision in the House Committee bill that became CAA section 122, requiring EPA to study and then take action to regulate radioactive air pollutants and three other air pollutants).

[562] Statement of Administrator Costle, Hearings before the Subcommittee on Energy Production and Supply of the Senate Committee on Energy and Natural Resources (Apr. 5, 7, May 25, June 24 and 30, 1977), 1977 CAA Legis. Hist. at 3532 (discussing the relationship between the National Energy Plan and the Administration's proposed CAA amendments). Some of the specific changes to the CAA include the addition of the PSD program, visibility protections, requirements for nonattainment areas, and stratospheric ozone provisions.

[563] H.R. Rep. No. 101–490, at 144 (May 17, 1990).

[564] H.R. Rep. No. 101–490, at 144 (May 17, 1990). Some of the changes adopted in 1990 include revisions to the NAAQS nonattainment program, a more aggressive and substantially revised CAA section 112, the new acid rain program, an operating permits program, and a program for phasing out of certain ozone depleting substances.

are by far the largest source of stationary source emissions. They emit almost three times as much CO_2 as do the next nine stationary source categories combined, and approximately the same amount of CO_2 emissions as all of the nation's mobile sources. The only controls available that can reduce CO_2 emissions from existing power plants in amounts commensurate with the problems they pose are the measures in building blocks 2 and 3, or far more expensive measures such as CCS.

Thus, interpreting the ''system of emission reduction'' provisions in CAA section 111(d)(1) and (a)(1) to allow the nation to meaningfully address the urgent and severe public health and welfare threats that climate change pose is consistent with what the CAA was designed to do.[565] This interpretation is also consistent with the cooperative purpose of section 111(d) to assure that the CAA comprehensively address those threats through the mechanism of state plans, where the states assume primary responsibility under federal leadership. *See King* v. *Burwell,* 576 U.S. (2015), No. 14–114 (2015), slip op. at 15 (''We cannot interpret federal statutes to negate their own stated purposes'' (quoting *New York State Dept. of Social Servs.* v. *Dublino,* 413 U.S. 405, 419–20 (1973)); *id.* at 21 (''A fair reading of legislation demands a fair understanding of the legislative plan.'').[566]

(b) *Purpose of encouraging pollution prevention.*

Interpreting ''system of emission reduction'' to include building blocks 2 and 3 is also consistent with the CAA's purpose to encourage pollution prevention. CAA section 101(c) states that ''[a] primary goal of [the CAA] is to encourage or otherwise promote reasonable federal, state, and local governmental actions, consistent with the provisions of this chapter, for pollution prevention.'' Indeed, in the U.S. Code, in which the CAA is codified as chapter 85, the CAA is entitled, ''Air Pollution Prevention and Control.''[567] CAA section 101(a)(3) describes ''air pollution prevention'' as ''the reduction or elimination, through *any* measures, of the amount of pollutants produced or created at the source''. (Emphasis added.) The reference to ''any measures'' highlights the breadth of what Congress considered to be pollution prevention, that is, any and all measures that reduce or eliminate pollutants at the source.[568]

The measures in building blocks 2 and 3 qualify as ''pollution prevention'' measures because they are ''any measures'' that ''reduc[e] or eliminate[e] . . . the amount of pollutants produced or created at the [fossil fuel-fired affected] source[s].'' Thus, consistent with the CAA's primary goals, it is therefore reasonable to interpret a ''system of emission reduction,'' as including the pollution prevention measures in building blocks 2 and 3.

(c) *Purpose of advancing technology to control air pollution.*

This final rule is also consistent with CAA section 111's purpose of promoting the advancement of pollution control technology based on the expectation that American industry will be able to develop innovative solutions to the environmental problems.

The legislative history and case law of CAA section 111 identify three different ways that Congress designed CAA section 111 to authorize standards of performance that promote technological improvement: (i) The development of technology that may be treated as the ''best system of emission reduction . . . adequately demonstrated;'' under CAA section 111(a)(1);[569] (ii) the expanded use of the best demonstrated technology;[570] and (iii) the development of emerging technology.[571] This rule is consistent with the second of those ways—it expands the use of the measures in building blocks 2 and 3, which are already established and provide substantial reductions at reasonable cost. As discussed below, the use of the measures in these building blocks will be most fully expanded when organized markets develop, and our expectation that those markets will develop is consistent with the Congress's view, just described, that CAA section 111 should promote technological innovation.

This final rule is also consistent with Congress's overall view that the CAA Amendments as a whole were designed to promote technological innovation. In enacting the CAA, Congress articulated its expectation that American industry would be creative and come up with innovative solutions to the urgent and severe problem of air pollution. This is manifest in the well-recognized technology-forcing nature of the CAA, and was expressed in numerous, sometimes ringing, statements in the legislative history about the belief that American industry will be able to develop the needed technology. For example, in the 1970 floor debates, Congress recalled that the nation had put a man on the moon a year before and had won World War II a quarter century earlier, and attributed much of the credit for those singular achievements to American industry and its ability to be productive and innovative. Congress expressed confidence that American industry

[565] In addition, as we have noted, in designing the 1970 CAA Amendments, Congress was aware that carbon dioxide increased atmospheric temperatures. In 1970, when Congress learned that ''the carbon dioxide balance might result in the heating up of the atmosphere'' and that particulate matter ''might cause reduction in radiation,'' the Nixon Administration assured Congress that ''[w]hat we are trying to do, however, in terms of our air pollution effort should have a very salutary effect on either of these.'' Testimony of Charles Johnson, Jr., Administrator of the Consumer Protection and Environmental Health Service (Administration Testimony), Hearing of the House Subcommittee on Public Health and Welfare (Mar. 16, 1970), 1970 CAA Legis. Hist. at 1381. Many years later, scientific consensus has formed around the particular causes and effects of climate change; and the tools put in place in 1970 can be read fairly to address these concerns.

[566] This final rule is also consistent with the CAA's purpose of protecting health and welfare. For example, the CAA authorizes the EPA to regulate air pollutants as soon as the EPA can determine that those pollutants pose a risk of harm, and not to wait until the EPA can prove that those pollutants actually cause harm. *See* H.R. Rep. No. 95–294, at 49 (May 12, 1977), 1977 CAA Legis. Hist. at 2516 (describing the CAA as being designed . . . to assure that regulatory action can effectively prevent harm before it occurs; to emphasize the predominant value of protection of public health''). The protective spirit of the CAA extends to the present rule, in which the EPA regulates on the basis of building blocks 2 and 3 because the range of available and cost-effective measures in those building blocks achieves more pollution reduction than building block 1 alone. Indeed, add-on controls that are technically capable of reducing CO_2 emissions at the scale necessitated by the severity of the environmental risk—for example, CCS technology—are not as cost-effective as building blocks 2 and 3 on an industry-wide basis, and while the costs of the add-on controls can be expected to be reduced over time, it is not consonant with the protective spirit of the CAA to wait.

[567] *See* Air Quality Act of 1967, Pub. L. 90–148, § 2, 81 Stat. 485 (Nov. 21, 1967) (adding ''Title I—Air Pollution Prevention and Control'' to the CAA, along with Congress' initial findings and purposes under CAA section 101).

[568] Section 101 emphasizes the importance of air pollution prevention in two other provisions: CAA section 101(b)(4) states that one of ''the purposes of [title I of the CAA, which includes section 111] are . . . (b) to encourage and assist the development and operation of regional air pollution prevention and control programs.'' CAA section 101(a)(3) adds: ''The Congress finds—. . . (3) that air pollution prevention . . . and air pollution control at its source is the primary responsibility of states and local governments.'' In fact, section 101 mentions pollution prevention no less than 6 times.

[569] *See Portland Cement Ass'n* v. *Ruckelshaus,* 486 F.2d 375, 391 (D.C. Cir. 1973) (the best system of emission reduction must ''look[] toward what may fairly be projected for the regulated future, rather than the state of the art at present'').

[570] *See* S. Rep. No. 91–1196, at 15 (''The maximum use of available means of preventing and controlling air pollution is essential to the elimination of new pollution problems'').

[571] *See Sierra Club* v. *Costle,* 657 F.2d at 351 (upholding a standard of performance designed to promote the use of an emerging technology).

could meet the challenges of developing air pollution controls as well.[572]

(d) *Response to commenters concerning purpose.*

Commenters have stated that the proposed rule ''would transform CAA section 111 into something untethered to its statutory language and unrecognizable to the Congress that created it.'' [573] Commenters with this line of comments focused on the ramifications of building block 4, which the EPA has decided does not belong in BSER using EPA's historical interpretation of BSER. Regardless of whether the comments are accurate with respect to building block 4 measures, they are certainly not accurate with respect to the three building blocks that the EPA is defining as the BSER. This rule would be recognizable to the Congresses that created and amended CAA section 111 and is carefully fashioned to the statutory text in CAA section 111(d) and (a)(1). This final rule would be recognizable to the Congress that adopted CAA section 111 in 1970 as part of a bold, far-reaching law designed to address comprehensively an air pollution crisis that threatened the health of millions of Americans; to have EPA and the States work cooperatively to develop state-specific approaches to address a national problem; to challenge industry to meet that crisis with creative energy; and to give the EPA broad authority—under section 111 and other provisions—to craft the needed emission limitations. This final rule would be recognizable to the Congress that revised CAA section 111 in 1977 to explicitly authorize that standards be based on actions taken by third parties (fuel cleaners). And this final rule would be recognizable to the Congress that revised CAA section 111 in 1990 to be linked to the Acid Rain Program that Congress adopted at the same time, which regulated the same industry (fossil fuel-fired EGUs) through some of the same measures (generation shifts and RE), and that explicitly acknowledged that those measures (RE) would also reduce CO_2 and thereby address the dangers of climate change. To reiterate, for the reasons explained in this preamble, this rule is grounded in our reasonable interpretation of CAA section 111(d) and (a)(1).

(8) *Constraints on the BSER—treatment of building block 4 and response to comments concerning precedents.*

Although the BSER provisions are sufficiently broad to include, for affected EGUs, the measures in building blocks 2 and 3, they also incorporate significant constraints on the types of measures that may be included in the BSER. We discuss those constraints in this section. These constaints explain why we are not including building block 4 in the BSER. In addition, these constraints explain why our reliance on building blocks 2 and 3 will have limited precedential effect for other rulemakings, and serve as our basis for responding to commenters who expressed concern that reliance on building blocks 2 and 3 would set a precedent for the EPA to rely on similar measures in promulgating future air pollution controls for other sectors.[574]

As discussed above, the emission limits in the CAA section 111(d) emission guidelines that this rule promulgates are based on the EPA's determination, for the affected EGUs, of the ''system of emission reduction'' that is the ''best,'' taking into account ''cost'' and other factors, and that is ''adequately demonstrated.'' Those components include certain interpretations and applications and provide constraints on the types of measures or controls that the EPA may determine to include in the BSER.

(a) *Emission reductions from affected sources.*

The first constraint is that the BSER must assure emission reductions from the affected sources. Under section 111(d)(1), the states must submit state plans that ''establish[] standards of performance for any existing source,'' and, under section 111(a)(1) and the EPA's implementing regulations, those standards are informed by the EPA's determination of the best system of emission reduction adequately demonstrated. Because the emission standards must apply to the affected sources, actions taken by affected sources that do not result in emission reductions from the affected sources—for example, offsets (*e.g.,* the planting of forests to sequester CO_2)—do not qualify for inclusion in the BSER. Building blocks 2 and 3 achieve emission reductions from the affected EGUs, and thus are not precluded under this constraint.

(b) *Controls or measures that affected EGUs can implement.*

The second constraint is that because the affected EGUs must be able to achieve their emission performance rates through the application of the BSER, the BSER must be controls or measures that the EGUs themselves can implement. Moreover, as noted, the D.C. Circuit has established criteria for achievability in the section 111(b) case law; *e.g.,* sources must be able to achieve their standards under a range of circumstances. If those criteria are applicable in a section 111(d) rule, the BSER must be of a type that allows sources to meet those achievability criteria. As noted, under this rule, affected EGUs can achieve their emission performance rates in the various circumstances under which they operate, through the application of the building blocks.

(c) *''Adequately demonstrated.''*

The third constraint is that the system of emission reduction that the EPA determines to be the best must be ''adequately demonstrated.'' To qualify as the BSER, controls and measures must align with the nature of the regulated industry and the nature of the pollutant so that implementation of those controls or measures will result in emission reductions from the industry and allow the sources to achieve their emission performance standards. The history of the effectiveness of the controls or other measures, or other indications of their effectiveness, are important in determining whether they are adequately demonstrated.

More specifically, the application of building blocks 2 and 3 to affected EGUs has a number of unique characteristics. Building blocks 2 and 3 entail the production of the same amount of the same product—electricity, a fungible product that can be produced using a variety of highly substitutable generation processes—through the cleaner (that is, less CO_2-intensive) processes of shifting dispatch from steam generators to existing NGCC units, and from both steam generators and NGCC units to renewable generators.

[572] Sen. Muskie, S. Debates on S. 4358 (Sept. 21, 1970), 1970 CAA Legis. Hist. at 227 (''At the beginning of World War II industry told President Roosevelt that his goal of 100,000 planes each year could not be met. The goal was met, and the war was won. And in 1960, President Kennedy said that America would land a man on the moon by 1970. And American industry did what had to be done. Our responsibility in Congress is to say that the requirements of this bill are what the health of the Nation requires, and to challenge polluters to meet them.''). *See* Blaime, A.J., *The Arsenal of Democracy: FDR, Detroit, and an Epic Quest to Arm an America at War* (Houghton Mifflin Harcourt 2014); Carew, Michael G., *Becoming the Arsenal: The American Industrial Mobilization for World War II, 1938–1942* (University Press of America, Inc. 2010).

[573] UARG comment at 31. *See id.* at 18, 29, 49. This comment appears to be a reference to the Supreme Court's statement in *UARG. See Util. Air Reg. Group* v. *EPA,* 134 S. Ct. 2427, 2444 (2014).

[574] Commenters offered hypothetical examples to illustrate their concerns over precedential effects, discussed below. Some commenters objected that our proposed interpretation of the BSER failed to include limiting principles. In the Legal Memorandum, we note that the statutory constraints discussed in this section of the preamble constitute limits on the type of the BSER that the EPA is authorized to determine.

The physical properties of electricity and the highly integrated nature of the electricity system allow the use of these cleaner processes to generate the same amount of electricity. In addition, the electricity sector is primarily domestic—little electricity is exported outside the U.S.—and there is low capacity for storage. In addition, the electricity sector is highly regulated, planned, and coordinated. As a result, holding demand constant, an increase in one type of generation will result in a decrease in another type of generation. Moreover, the higher-emitting generators, which are fossil fuel-fired, have higher variable costs than renewable generators, so that increased renewable generation will generally back out fossil fuel-fired generation.

Because of these characteristics, the electricity sector has a long and well-established history of substituting one type of generation for another. This has occurred for a wide variety of reasons, many of which are directly related to the system's primary purposes and functions, as well as for environmental reasons. As a result, at present, there is a well-established network of business and operational relationships and past practices that supports building blocks 2 and 3. As noted elsewhere, a large segment of steam generators already have business relationships with existing NGCC units, and a large segment of all fossil fuel-fired EGUs already own, co-own, or have invested in RE.

Many of these characteristics are unique to the utility power sector. Moreover, this complex of characteristics, ranging from the physical properties of electricity and the integrated nature of the grid to the institutional mechanisms that assure reliability and the existing practices and business relationships in the industry, combine to facilitate the implementation of building blocks 2 and 3 in a uniquely efficient manner. This supports basing the emission limits on the ability of owners and operators of fossil fuel-fired EGUs to replace their generation with cleaner generation in other locations, sometimes owned by other entities.

As noted above, commenters offered hypothetical examples to illustrate their concerns over precedential effects. Most of their concerns focused on building block 4, and most of their hypothetical examples concerned reductions in demand for various types of products. We address these concerns in the response to comments document, but we note here that, in any event, these concerns are mooted because we are not finalizing building block 4. Some commenters offered hypothetical examples for building blocks 2 and 3 as well. For example, some commenters asserted that the EPA could ''develop standards of performance for tailpipe emissions from motor vehicles'' by ''requiring car owners to shift some of their travel to buses,'' which the commenters considered analogous to building block 2; or by ''requiring there to be more electric vehicle purchases,'' which the commenters considered analogous to building block 3.[575]

Commenters' concerns over precedential impact cannot be taken to mean that the building blocks should not be considered to meet the requirements of the BSER or that the affected EGUs cannot be considered to meet the emission limits by implementing those measures. Moreover, because many of these individual characteristics, and their inherent complexity, are unique to the utility power sector, building blocks 2 and 3 as applied to fossil fuel-fired EGUs will have a limited precedent for other industries and other types of rulemakings. For example, the commenter's hypothetical examples noted above are inapposite for several reasons. The hypotheticals appear to be premised on government action mandating actions not implementable by emitting sources (*e.g.,* that a government would ''require[e] car owners to shift some of their travel to buses, or . . . require[e] there to be more electric vehicle purchases''), whereas the measures in building blocks 2 and 3 can be implemented by the affected EGUs. Nor have commenters attempted to address how car owners shifting travel to buses or purchasing more electric vehicles could be translated into lower tailpipe standards for motor vehicles.[576]

(d) *''Best'' in light of ''cost . . . nonair quality health and environmental impact and energy requirements'' and EPA's past practice and current policy.*

The fourth constraint, or set of constraints, is that the system of emission reduction must be the ''best,'' ''taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements.'' As noted, in light of the D.C. Circuit case law, the EPA has considered cost and energy factors on both an individual source basis and on the basis of the nationwide electricity sector. In determining what is ''best,'' the EPA has broad discretion to balance the enumerated factors.[577] In interpreting and applying these provisions in this rulemaking to regulate CO_2 emissions from affected EGUs under section 111(d), we are acting consistently with our past practice for applying these provisions in previous section 111 rulemakings and for regulating air pollutants from the electricity sector under other provisions of the CAA, as well as current policy.

The great majority of our regulations under section 111 have been 111(b) regulations for new sources. As discussed in the Legal Memorandum and briefly below, the BSER identified under section 111(b) is designed to assure that affected sources are well controlled at the time of construction, and that approach is consistent with the design expressed in the legislative history for the 1970 CAA Amendments that enacted the provision.

Traditionally, CAA section 111 standards have been rate-based, allowing as much overall production of a particular good as is desired, provided that it is produced through an appropriately clean (or low-emitting) process. CAA section 111 performance standards have primarily targeted the means of production in an industry and not consumers' demand for the product. Thus, the focus for the BSER has been on how to most cleanly produce a good, not on limiting how much of the good can be produced.

One example of the focus under section 111 on clean production, not limitation of product is provided by the revised new source performance standards for electric utility steam generating units that we promulgated in 1979 following the 1977 CAA Amendments to limit emissions of SO_2, PM, and NO_X. In relevant part, the revised standards limited SO_2 emissions to 1.20 lb/million BTU heat input and imposed a 90 percent reduction in potential SO_2 emissions. This was based on the application of flue gas desulfurization (FGD) together with coal preparation techniques. In the preamble, we explain that ''[t]he intent of the final standards is to encourage power plant owners and operators to install the best available FGD systems and to implement effective operation and maintenance procedures but not to create power supply disruptions.''[578] [579]

[575] UARG comment at 2–3.

[576] In any event, it is questionable whether measures such as those hypothesized by the commenters would be consistent with the provisions of Title II.

[577] *See Lignite Energy Council* v. *EPA,* 198 F.3d 930, 933 (D.C. Cir. 1999).

[578] *See, e.g.,* 44 FR 33580, at 33599 (June 11, 1979). In this rulemaking, the EPA recognized the ability of the integrated grid to minimize power disruptions: ''When electric load is shifted from a

Continued

EPA has taken the same overall approach in its section 111(d) rules,[580] including the CAMR rule noted below.

Similarly, in a series of rulemakings regulating air pollutants from EGUs under several provisions of the CAA, we have focused our efforts on assuring that electricity is generated through cleaner or lower-emitting processes, and we have not sought to limit the aggregate amount of electricity that is generated. We describe those rules in section II, elsewhere in this section V.B.3., and in the Legal Memorandum.

For example, as discussed in the Legal Memorandum, in the three transport rules promulgated under CAA section 110(a)(2)(D)(i)(I)—the NO_X SIP Call, CAIR, and CSAPR—which regulated precursors to ozone-smog and particulate matter, the EPA based certain aspects of the regulatory requirements on the fact that fossil fuel-fired EGUs could shift generation to lower-emitting sources. In CAMR, the 2005 rulemaking under section 111(d) regulating mercury emissions from coal-fired EGUs, the EPA based the first phase of control requirements on the actions the affected EGUs were required to take under CAIR, including shifting generation to lower-emitting sources. In addition, as also discussed in the Legal Memorandum, in the EPA's 2012 MATS rule regulating mercury from coal-fired EGUs under section 112, at industry's urging, the EPA allowed compliance deadlines to be extended for coal-fired EGUs that desired to substitute replacement power of any type, including NGCC units or RE, for compliance purposes.

While these and other rulemakings for fossil fuel-fired EGUs took different approaches towards lower-emitting generation and renewable generation, they all were based on control measures that reduced emissions without reducing aggregate levels of electricity generation. It should be noted that even though some of those rules established overall emission limits in the form of budgets implemented through a cap-and-trade program, the EPA recognized that the fossil fuel-fired EGUs that were subject to the rules could comply by shifting generation to lower-emitting EGUs, including relying on RE. In this manner, the rules limited emissions but on the basis that the industry could implement lower-emitting processes, and not based on reductions in overall generation.

We are applying the same approach to this rulemaking. Our basis for this rulemaking is that affected EGUs can implement a system of emission reduction that will reduce the amount of their emissions without reducing overall electricity generation. This approach takes into account costs by minimizing economic disruption as well as the nation's energy requirements by avoiding the need for environmental-based reductions in the aggregate amount of electricity available to the consumer, commercial, and industrial sectors.

This approach is a reasonable exercise of the EPA's discretion under section 111, consistent with the U.S. Supreme Court's statements in its 2011 decision, *American Electric Power Co.* v. *Connecticut,* that the CAA and the EPA actions it authorizes displace any federal common law right to seek abatement of CO_2 emissions from fossil-fuel fired power plants. There, the Court emphasized that CAA section 111 authorizes the EPA—which the Court identified as the ''expert agency''—to regulate CO_2 emissions from fossil fuel-fired power plants based an ''informed assessment of competing interests . . . . Along with the environmental benefit potentially achievable, our Nation's energy needs and the possibility of economic disruption must weigh in the balance.'' [581]

Similarly, the D.C. Circuit, in a 1981 decision upholding the EPA's section 111(b) standards for air pollutants from fossil fuel-fired EGUs, stated that section 111 regulations concerning the electric power sector ''demand a careful weighing of cost, environmental, and energy considerations.'' [582] This exercise of policy discretion is consistent with Congress's expectation that the Administrator ''should determine the achievable limits'' [583] and ''would establish guidelines as to what the best system for each such category of existing sources is.'' [584] As the D.C. Circuit explained, ''[i]t seems likely that if Congress meant . . . to curtail EPA's discretion to weigh various policy considerations it would have explicitly said so in section 111, as it did in other parts of the statute.'' [585]

Our interpretation that CAA section 111 targets supply-side activities that allow continued production of a product through use of a cleaner process, rather than targeting consumer-oriented behavior, also furthers Congress' intent of promoting cleaner production measures ''to protect and enhance the quality of the Nation's air resources so as to promote the public health and welfare and the productive capacity of its population.'' [586] This principle is also consistent with promoting ''reasonable . . . governmental actions . . . for pollution prevention.'' [587]

In this rule, we are applying that same approach in interpreting the BSER provisions of section 111. That is, we are basing the regulatory requirements on measures the affected EGUs can implement to assure that electricity is generated with lower emissions, taking into account the integrated nature of the industry and current industry practices. Building blocks 1, 2 and 3 fall squarely within this paradigm; they do not require reductions in the total amount of electricity produced.

We recognize that commenters have raised extensive legal concerns about building block 4. We recognize that building block 4 is different from building blocks 1, 2, and 3 and the pollution control measures that we have considered under CAA section 111. Accordingly, under our interpretation of section 111, informed by our past practice and current policy, today's final action excludes building block 4 from the BSER. Building block 4 is outside our paradigm for section 111 as it targets

---

new steam-electric generating unit to another electric generating unit, there would be no net change in reserves within the power system. Thus, the emergency condition provisions prevent a failed FGD system from impacting upon the utility company's ability to generate electric power and prevents an impact upon reserves needed by the power system to maintain reliable electric service.'' *Id.*

[579] The EPA's 1982 revised new source performance standards for certain stationary gas turbines provide another example of a rulemaking that focused controls on reducing emissions, as well as reliance on the integrated grid to avoid power disruptions. 44 FR 33580 (June 11, 1979). In response to comments that requested a NO_X emission limit exemption for base load utility gas turbines, the EPA explained that ''for utility turbines . . . since other electric generators on the grid can restore lost capacity caused by turbine down time'' the NO_X emission limit of 1150 ppm for such turbines would not be rescinded. 44 FR 33580, at 33597–98.

[580] *See* ''Phosphate Fertilizer Plants; Final Guideline Document Availability,'' 42 FR 12022 (Mar. 1, 1977); ''Standards of Performance for New Stationary Sources; Emission Guideline for Sulfuric Acid Mist,'' 42 FR 55796 (Oct. 18, 1977); ''Kraft Pulp Mills, Notice of Availability of Final Guideline Document,'' 44 FR 29828 (May 22, 1979); ''Primary Aluminum Plants; Availability of Final Guideline Document,'' 45 FR 26294 (Apr. 17, 1980); ''Standards of Performance for New Stationary Sources and Guidelines for Control of Existing Sources: Municipal Solid Waste Landfills, Final Rule,'' 61 FR 9905 (Mar. 12, 1996).

[581] *American Electric Power Co.* v. *Connecticut,* 131 S. Ct. 2527, 2539–40 (2011).

[582] *Sierra Club* v. *EPA,* 657 F.2d 298, 406 (D.C. Cir. 1981). *Id.* at 406 n. 526.

[583] S. Rep. No. 91–1196, at 15–16 (Sept. 17, 1970), 1970 CAA Legis. Hist. at 415–16 (explaining that the ''[Administrator] should determine the achievable limits and let the owner or operator determine the most economic, acceptable technique to apply.'').

[584] H.R. Rep. No. 95–294, at 195 (May 12, 1977).

[585] *Sierra Club* v. *Costle,* 657 F.2d 298, 330 (D.C. Cir. 1981).

[586] CAA section 101(b)(1).

[587] CAA section 101(c).

consumer-oriented behavior and demand for the good, which would reduce the amount of electricity to be produced.

Although numerous commenters urged us to include demand-side EE measures as part of the BSER, as we had proposed to do, we conclude that we cannot do so under our historical practice, current policy, and current approach to interpreting section 111 as well as our historical practice in regulating the electricity sector under other CAA provisions. While building blocks 2 and 3 are rooted in our past practice and policy, building block 4 is not and would require a change (which we are not making) in our interpretation and implementation and application of CAA section 111.

Excluding demand-side EE measures from the BSER has the benefit of allaying legal and other concerns raised by commenters, including concerns that individuals could be ''swept into'' the regulatory process by imposing requirements on ''every household in the land.'' [588] While building block 4 could have been implemented without imposing requirements on individual households, this final rule resolves any doubt on this matter and is not based on the inclusion of demand-side EE as part of the BSER.

By the same token, we are not finalizing reduced generation of electricity overall as the BSER. Instead, components of the BSER focus on shifting generation to lower- or zero-emitting processes for producing electricity.[589]

(e) *Constraints for new sources.*

For new sources, practical and policy concerns support the interpretation of basing the BSER on controls that new sources can install at the time of construction, so that they will be well-controlled throughout their long useful lives. This approach is consistent with the legislative history. We discuss this at greater length in the Legal Memorandum.

4. Relationship Between a Source's Implementation of Building Blocks 2 and 3 and Its Emissions

In this section, we discuss the relationship between an affected EGU's implementation of the measures in building blocks 2 and 3 and that affected EGU's own generation and emissions. As discussed above, an affected EGU subject to a CAA section 111(d) state plan that imposes an emission rate-based standard may achieve that standard in part by implementing the measures in building block 2 (for a steam generator) and building block 3 (for a steam generator or combustion turbine). That is, an affected EGU may invest in low- or zero-emitting generation and may apply credits from that generation against its emission rate. Those credits reduce the affected EGU's emission rate and thereby help it to achieve its emission limit.

In addition, the additional low- or zero-emitting generation that results from the affected EGU's investment will generally displace higher-emitting generation. This is because, as described above, higher-emitting generation generally has higher variable costs, reflecting its fuel costs, than, at least, zero-emitting generation. Displacement of higher-emitting generation will lower overall CO_2 emissions from the source category of affected EGUs.

If an affected EGU implements building block 2 or 3 by reducing its own generation, it will reduce its own emissions. However, the affected EGU may also or alternatively choose to implement building block 2 or 3 by investing in lower- or zero-emitting generation that does not, in and of itself, reduce the amount of its own generation or emissions. Even so, implementation of building blocks 2 and 3 will reduce CO_2 from some affected EGUs, and therefore reduce CO_2 on a source category-wide basis.

This outcome is, however, consistent with the requirements of CAA section 111(d)(1) and (a)(1). To reiterate, CAA section 111(d)(1) requires that ''any existing source'' have a ''standard of performance,'' defined under CAA section 111(a)(1) as ''a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction . . . adequately demonstrated [BSER] . . . .'' These provisions require by their terms that ''any existing source'' must have a ''standard of performance,'' but nothing in these provisions requires a particular amount—or, for that matter, any amount—of emission reductions from each and every existing source. That the ''standard of performance'' is defined on the basis of the ''degree of emission limitation achievable through the application of the [BSER]'' does not mean that each affected EGU must achieve some amount of emission reduction, for the following reasons.

The cornerstone of the definition of the term ''standard of performance'' is the BSER. In determining the BSER, the EPA must consider the amount of emission reduction that the system may achieve, and must consider the ability of the affected EGUs to achieve the emission limits that result from the application of the BSER. The EPA is authorized to include in the BSER, for this source category, the measures in building blocks 2 and 3 because, when applied to the source category, these measures result in emission standards that may be structured to ensure overall emission reductions from the source category and remain achievable by the affected EGUs. This remains so regardless of whether the ''degree of emission limitation achievable through the application of the [BSER]'' by any particular source results in actual emission reductions from that source.

The application of the building blocks has an impact that is similar to that of an emissions trading program, under which, overall, the affected sources reduce emissions, but any particular source does not need to reduce its emissions and, in fact, may increase its emissions, as long as it purchases sufficient credits or allowances from other sources. In fact, we expect that many states will carry out their obligations under this rule by imposing standards of performance that incorporate trading or other multi-entity generation-replacement strategies. Indeed, any emission rate-based standard may not necessarily result in emission reductions from any particular affected source (or even all of the affected sources in the category) as a result of the ability of the particular source (or even all of them) to increase its production and, therefore, its emissions, even while maintaining the required emission rate.

5. Reduced Generation and Implementation of the BSER

In the proposed rulemaking, we described the BSER as the measures included in building block 1 as well the set of measures included in building blocks 2, 3 and 4 or, in the alternative, reduced generation or utilization by the affected EGUs in the amount of building blocks 2, 3 and 4. In this final rule, based on the comments and further evaluation, we are refining our approach to the BSER. Specifically, we are determining the BSER as the combination of measures included in building blocks 1, 2, and 3.Building blocks 2 and 3 entail substitution of lower-emitting generation for higher-emitting generation, which ensures that aggregate production levels can continue to meet demand even where an individual affected EGU decreases its

[588] *See Util. Air Reg. Group* v. *EPA,* 134 S. Ct. 2427, 2436 (2014).

[589] As discussed below, however, reduced generation remains important to this rule in that it is one of the methods for implementing the building blocks.

own output to reduce emissions. The amount of generation from the increased utilization of existing NGCC units determines a portion of the amount of reduced generation that affected fossil fuel-fired steam EGUs could undertake to achieve building block 2, and the amount of generation from the use of expanded lower- or zero-emitting generating capacity that could be provided, determines a portion of the amount of reduced generation that affected fossil fuel-fired steam EGUs, as well as the entire amount of reduced generation that affected NGCC units could undertake to implement building blocks 2 and 3. This section discusses the reasons that reduced generation is one of the set of reasonable and well-established actions that an affected EGU can implement to achieve its emission limits. We are not finalizing our proposal that reduced overall generation of electricity may by itself be considered the BSER, for the reason that reduced generation by itself does not fit within our historical and current interpretation of the BSER. Specifically, reduced generation by itself is about changing the amount of product produced rather than producing the same product with a process that has fewer emissions.

a. *Background.* As noted, for both rate-based and mass-based state plans, affected EGUs may take a set of actions to comply with their emission standards. An affected EGU may comply with an emission rate-based standard (*e.g.,* a limit on the amount of CO_2 per MWh) by acquiring, through one means or another, credits from lower- or zero-emitting generation (building blocks 2 or 3) to reduce its emission rate for compliance purposes. In addition, the affected EGU may reduce its generation, and if it does so, it then needs to acquire fewer of those credits to meet its emission rate.[590] Under these circumstances, the affected EGU would in effect replace part of its higher-emitting generation with lower- or zero-emitting generation. On the other hand, an affected EGU that is subject to a mass-based standard—for example, a requirement to hold enough allowances to cover its emissions (*e.g.,* one allowance for each ton of emissions in any year)—may comply at least in part by reducing its generation and, thus, its emissions. Therefore, one type of action that an affected EGU may take to achieve either of these emission limits is to reduce its generation. Further, reduced generation by individual sources offers a pathway to compliance in and of itself. That is, a state may adopt a mass-based goal, assign mass-based standards to its sources, and those sources may comply with their mass-based limits by, in addition to implementing building block 1 measures, reducing their generation in the appropriate amounts, and without taking any other actions.

b. *Well-established use of reduced generation to comply with environmental requirements.* Reduced generation is a well-established method for individual fossil fuel-fired power plants to comply with their emission limits.

Reduced generation in the amounts contemplated in this rule, as undertaken by individual sources to achieve their emission limits, reduces emissions from the affected sources, but because of the integrated and interconnected nature of the power sector, can be accommodated without significant cost or disruption. The electric transmission grid interconnects the nation's generation resources over large regions. Electric system operators coordinate, control, and monitor the electric transmission grid to ensure cost-effective and reliable delivery of power. These system operators continuously balance electricity supply and demand, ensuring that needed generation and/or demand resources are available to meet electricity demand. Diverse resources generate electricity that is transmitted and distributed through a complex system of interconnected components to end-use consumers.

The electricity system was designed to meet these core functions. The three components of the electricity supply system—generation, transmission and distribution—coordinate to deliver electricity from the point of generation to the point of consumption. This interconnectedness is a fundamental aspect of the nation's electricity system, requiring a complicated integration of all components of the system to balance supply and demand and a federal, state and local regulatory network to oversee the physically interconnected network. Electricity from a diverse set of generation resources such as natural gas, nuclear, coal and renewables is distributed over high-voltage transmission lines. The system is planned and operated to ensure that there are adequate resources to meet electricity demand plus additional available capacity over and above the capacity needed to meet normal peak demand levels. System operators have a number of resources potentially available to meet electricity demand, including electricity generated by electric generation units of various types as well as demand-side resources. Importantly, if generation is reduced from one generator, safeguards are in place to ensure that adequate supply is still available to meet demand. We describe these safeguards in the background section of this preamble.

Both Congress and the EPA have recognized reduced generation as one of the measures that fossil fuel-fired EGUs may implement to reduce their emissions of air pollutants and thereby achieve emission limits. Congress, in enacting the allowance requirements in CAA Title IV, under which fossil fuel-fired EGUs must hold an allowance for each ton of SO_2 emitted, explicitly recognized that fossil fuel-fired EGUs could meet this requirement by reducing their generation. In fact, Congress anticipated that fossil fuel-fired EGUs may choose to comply with the SO_2 emission limits by reducing utilization, and included provisions that specifically addressed reduced utilization. For example, CAA section 408(c)(1)(B) includes requirements for an owner or operator of an EGU that meets the Phase 1 SO_2 reduction obligations and the NO_X reduction obligations "by reducing utilization of the unit as compared with its baseline or by shutting down the unit."

The EPA has also recognized in several rulemakings limiting emissions from fossil fuel-fired EGUs that reduced generation is one of the methods of emission reduction that an EGU was expected to rely on to achieve its emission limitations. Examples include rulemakings to impose requirements that sources implement BART to reduce their emissions of air pollutants that cause or contribute to visibility impairment. As explained earlier, for certain older stationary sources that cause or contribute to visibility impairment, including fossil fuel-fired EGUs, states must determine BART on the basis of five statutory factors, such as costs and energy and non-air quality impacts.[591] In 1980, the EPA promulgated a regulatory definition of BART: "an emission limitation based on the degree of reduction achievable through the best system of continuous emission reduction for each pollutant which is emitted by an existing stationary facility." [592] Both the statutory factors and the regulatory definition resemble the definition of the BSER under CAA section 111(a)(1)

[590] An affected EGU that is subject to an emission rate, *e.g.,* pounds of CO_2 per MWh generated, cannot achieve that rate simply by reducing its generation (unless it shuts down, in which case it would achieve a zero emission rate). This is because although reducing generation results in fewer emissions, it does not, by itself, result in fewer emissions per MWh generated.

[591] CAA section 169A(g)(2).

[592] 40 CFR 51.301.

(although, as noted, the statutory definition of BART is more technology focused than the definition of BSER). In its regional haze SIP, the State of New York determined that BART for the NO_X emissions from two coal-fired boilers that served as peaking units was caps on baseline emissions rates and annual capacity factors of 5 percent and 10 percent, respectively.[593]

There have been numerous other instances in which fossil fuel-fired EGUs have reduced their individual generation, or placed limits on their generation, in order to achieve, or obviate, emission standards. In fact, there are numerous examples of EGUs that take restrictions on hours of operation in their permits for the purpose of avoiding CAA obligations, including avoiding triggering the requirements of the Prevention of Significant Deterioration (PSD), Nonattainment New Source Review (NNSR), or Title V programs (including Title V fees), and avoiding triggering HAP requirements. Such restrictions may also be taken to limit emissions of pollutants, such as limiting emissions of criteria pollutants for attainment purposes.

More specifically, EPA's regulations for a number of air programs expressly recognize that certain sources may take enforceable limits on hours of operation in order to avoid triggering CAA obligations that would otherwise apply to the source. Stationary sources that emit or have the *potential to emit* a pollutant at a level that is equal to or greater than specified thresholds are subject to major source requirements.[594] A source may voluntarily obtain a synthetic minor limitation—that is, a legally and practicably enforceable restriction that has the effect of limiting emissions below the relevant level—to avoid triggering a major stationary source requirement.[595] Such synthetic minor limits may be based on restrictions on the hours of operation, as provided in EPA's regulations defining ''potential to emit,'' as well as on air pollution control equipment. ''Potential to emit'' is defined, for instance, in the regulations for the PSD program for permits issued under federal authority as: ''the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the source to emit a pollutant, including air pollution control equipment and *restrictions on hours of operation* . . . shall be treated as part of its design if the limitation or the effect it would have on emissions is federally enforceable,'' [596] or ''legally and practicably enforceable by a state or local air pollution control agency.'' [597] The regulations for other air programs similarly recognize that potential to emit may be limited through restrictions on hours of operations in their corresponding definitions of ''potential to emit.'' [598] These regulatory provisions make clear that restrictions on potential to emit include both ''air pollution control equipment'' and ''restrictions on hours of operation,'' and indicate that these are equally cognizable means of restricting emissions to comply with, or avoid, CAA requirements.[599]

As one of many examples of a fossil-fuel fired EGU taking restrictions on hours of operation for the purpose of avoiding CAA obligations, Manitowoc Public Utilities in Wisconsin obtained a Title V renewal permit that limited the operating hours of the single simple-cycle combustion turbine to not more than 194 hours per month, averaged over any consecutive 12 month period, as part of limiting its potential to emit for volatile organic compounds below the Title V threshold of 100 tpy, and carbon monoxide, NO_X and SO_2 below the PSD threshold of 250 tpy.[600] As another example, Sunbury Generation LP in Pennsylvania obtained a minor new source preconstruction permit, called a plan approval, for a repowering project from the Pennsylvania Department of Environmental Protection in 2013 that limited the hours of operation of three combined cycle combustion turbines that were planned for construction in order to remain below the significance threshold for GHGs.[601] The Legal Memorandum includes numerous other examples of power plants accepting permit limits that reduce generation to meet, or avoid the need to meet, emission limits.

There are several ways that an affected EGU may implement reduced generation. For example, an EGU may accept a permit requirement that specifically limits its operating hours. In addition, an EGU may treat the cost of its generation as including an additional amount associated with environmental impacts, which requires it to raise its bid price, so that the EGU is dispatched less.

c. *Other aspects of reduced generation.*

The amounts of increased existing NGCC generation and new renewables, in the amounts reflected in building blocks 2 and 3, can be substituted for generation at affected EGUs at reasonable cost. The NGCC capacity necessary to accomplish the levels of generation reduction proposed for building block 2 is already in operation or under construction. Moreover, it is reasonable to expect that the incremental resources reflected in building block 3 will develop at the levels requisite to ensure an adequate and reliable supply of electricity at the same time that affected EGUs may

[593] 77 FR 24794, 24810 (Apr. 25, 2012).

[594] *See, e.g.,* CAA sections 112(a)(1), 112(d)(1), 165(a), 169(1), 172(c)(5), 173(a) & (c), 501(2), 502(a), 302(j).

[595] *See, e.g.,* Memorandum from Terrell Hunt, Assoc. Enforcement Counsel, U.S. EPA, & John Seitz, Director, Stationary Source Compliance Div., U.S. EPA, *Guidance on Limiting Potential to Emit in New Source Permitting,* at 1–2, 6 (June 13, 1989), available at *http://www.epa.gov/region07/air/nsr/nsrmemos/lmitpotl.pdf* (''Restrictions on production or operation that will limit potential to emit include limitations on quantities of raw materials consumed, fuel combusted, *hours of operation,* or conditions which specify that the source must install and maintain controls that reduce emissions to a specified emission rate or to a specified efficiency level.'') (emphasis added).

[596] 40 CFR 52.21(b)(4) (emphasis added).

[597] John Seitz, Director, Office of Air Quality Planning and Standards, and Robert Van Heuvelen, Director, Office of Regulatory Enforcement, *Release of Interim Policy on Federal Enforceability of Limitations on Potential to Emit,* at 3 (Jan. 22, 1996), available at *http://www.epa.gov/region07/air/nsr/nsrmemos/pottoemi.pdf.*

[598] *See* 40 CFR 51.166(b)(4) (addressing SIP approved PSD programs), 51.165(a)(1)(iii) (addressing SIP approved NNSR programs), 70.2 (addressing Title V operating permit programs), and 63.2 (addressing hazardous air pollutants).

[599] *See, e.g.,* 40 CFR 52.21(b)(4).

[600] *See* Final Operation Permit No. 436123380–P10 for Manitowoc Public Utilities—Custer Street (Wis. Dept. Nat. Res., 8/19/2013), Condition ZZZ.1.a(1) at p. 9 (Limiting potential to emit) and n. 11 (''These conditions are established so that the potential emissions for volatile organic compounds will not exceed 99 tons per year and potential emissions for carbon monoxide, nitrogen oxides and sulfur dioxide emissions from the facility will not exceed 249 tons per year.''). *See also* Analysis and Preliminary Determination for the Renewal of Operation Permit 436123380–P01 (Wis. Dept. Nat. Res., 5/21/2013) at p. 5 (noting that the ''existing facility is a major source under Part 70 because potential emissions of sulfur dioxide, nitrogen oxides and carbon monoxide exceed 100 tons per year. The existing facility is a minor source under PSD and an area source of federal HAP'' and further noting that after renewal, ''the facility will continue to be a major source under Part 70 because potential emissions of sulfur dioxide, nitrogen oxides and carbon monoxide exceed 100 tons per year. The facility will also continue to be a minor source under PSD and an area source of federal HAP.'').

[601] *See* Plan Approval No. 55–00001E for Sunbury Generation LP (Pa. Dept. Env. Protection, 4/1/2013), Conditions #016 on pp. 24, 32 and 40 (limiting turbine units to operating no more than 7955, 6920, or 8275 hours in any 12 consecutive month period depending on which of three turbine options was selected); Memorandum from J. Piktel to M. Zaman, *Addendum to Application Review Memo for the Repowering Project* (Pa. Dept. Env. Protection, 4/1/2013) at p. 2 of 10 (noting that source had ''calculated a maximum hours per year (12 consecutive month period) of operation for the sources proposed for each of the turbine options in order to remain below the significance threshold for GHGs.'').

choose to reduce their CO_2 emissions by means of reducing their generation.

Reduced generation by affected EGUs, in the amounts that affected EGUs may rely on to implement the selected building blocks, will not have adverse effects on the utility power sector and will not reduce overall electricity generation. In light of the emission limits of this rule, because of the availability of the measures in building blocks 2 and 3, and because the grid is interconnected and the electricity system is highly planned, reductions in generation by fossil fuel-fired EGUs in the amount contemplated if they were to implement the building blocks, and occurring over the lengthy time frames provided under this rule, will result in replacement generation that generally is lower- or zero-emitting. Mechanisms are in place in both regulated and deregulated electricity markets to assure that substitute generation will become available and/or steps to reduce demand will be taken to compensate for reduced generation by affected EGUs. As a result, reduced generation will not give rise to reliability concerns or have other adverse effects on the utility power sector and are of reasonable cost for the affected source category and the nationwide electricity system.[602] All these results come about because the operation of the electrical grid through integrated generation, transmission, and distribution networks creates substitutability for electricity and electricity services, which allows decreases in generation at affected fossil fuel-fired steam EGUs to be replaced by increases in generation at affected NGCC units (building block 2) and allows decreases in generation at all affected EGUs to be replaced by increased generation at new lower- and zero-emitting EGUs (building block 3). Further, this substitutability increases over longer timeframes with the opportunity to invest in infrastructure improvements, and as noted elsewhere, this rule provides an extended state plan and source compliance horizon.

d. *Comments concerning limiting principles.*

A commenter stated that ''an interpretation of ['system of emission reduction'] that relies primarily on reduced utilization has no clear limiting principle.''[603] We disagree with this concern, for the following reasons.

As discussed, in this final rule, we are identifying the BSER as the combination of the three building blocks. Building blocks 2 and 3 entail substitution of lower- or zero-emitting generation for higher-emitting generation, and one component of that substitution is reduced generation, which is limited in several respects discussed below. Accordingly, our identification of the BSER in this final rule does not ''rel[y] primarily'' on reduced utilization in and of itself (and therefore reduced generation of the product overall, electricity) as the BSER. Rather, the BSER is, in addition to building block 1, the substitution of lower- or zero-emitting generation for higher emitting generation, and reduced utilization may be a way to implement that substitution and is one of numerous methods that affected EGUs may employ to achieve or help achieve the emission limits established by these emission guidelines.[604] The commenter's concerns over a perceived lack of a limiting principle cannot be taken to mean that reduced generation by higher-emitting EGUs cannot be considered to be a method for affected EGUs to achieve their emission limits.

Moreover, reduced generation, as applied to affected EGUs in this rule, is limited in a number of respects. The amount of reduced generation is the amount of replacement generation that is lower- or zero-emitting, that is of reasonable cost, that can be generated without jeopardizing reliability, and that meets the other requirements for the BSER. As discussed, that amount is the amount of generation in building blocks 2 and 3.[605]

Finally, as discussed, the integrated nature of the electricity system, coupled with the high substitutability of electricity, allows EGUs to reduce their generation without adversely affecting the availability of their product. Those characteristics facilitate replacement of generation that has been reduced, and for that reason, EGUs have a long history of reducing their generation and either replacing it directly or having it replaced through the operation of the interconnected electricity system through measures similar to those in building blocks 2 and 3. Thus, an EGU can either directly replace its generation, or simply reduce its generation, and in the latter case, the integrated grid, combined with the high degree of planning and various reliability safeguards, will result in entities providing replacement generation. This means that consumers receive exactly the same amount of the same product, electricity, after the reduced generation that they received before it. No other industry is both physically interconnected in this manner and manufactures such a highly substitutable product; as a result, the use of reduced generation is not easily transferrable to another industry.

6. Reasons That This Rule Is Within the EPA's Statutory Authority and Does Not Represent Over-Reaching

In this section, we respond to adverse comments that the EPA is overreaching in this rulemaking by attempting to direct the energy sector. These commenters construed the proposed rulemaking as the EPA proposing to mandate the implementation of the measures in the building blocks,

[602] Although, as discussed in the text in this section of the preamble, we are not treating reduced overall generation of electricity as the BSER (because it does not meet our historical and current approach of defining the BSER to include methods that allow the same amount of production but with a lower-emitting process) we note that reduced generation by individual higher-emitting EGUs to implement building blocks 2 and 3 meets the following criteria for the BSER: As the examples in the text and in the Legal Memorandum make clear, reduced generation is ''adequately demonstrated'' as a method of reducing emissions (because Congress and the EPA have recognized it and on numerous occasions, power plants have relied on it); it is of reasonable cost; it does not have adverse effects on energy requirements at the level of the individual affected source (because it does not require additional energy usage by the source) or the source category or the U.S.; and it does not create adverse environmental problems.

[603] EEI comment, at 284.

[604] Indeed, load shifting—as substitute generation is sometimes called—is an ''easy and fairly inexpensive strategy'' that ''may be used in conjunction with other control measures'' for ''emission reduction.'' Donald S. Shepard, ''A Load Shifting Model for Air Pollution Control in the Electric Power Industry,'' Journal of the Air Pollution Control Association, Vol. 20, No. 11, p. 760 (Nov. 1970). In fact, load shifting has been recognized as a pollution control technique as early as 1968, when it was included in the ''Chicago Air Pollution System Model'' for controlling incidents of extremely high pollution. E.J. Croke, et al., ''Chicago Air Pollution System Model, Third Quarterly Progress Report,'' Chicago Department of Air Pollution Control, p. 186 (1968) (discussing the feasibility of ''Control by Load Reduction'' in combination with load shifting as applied to the Commonwealth Edison Company), *available at http://www.osti.gov/scitech/servlets/purl/4827809*. The report also considered ''combining fuel switching and load reduction'' as a possible air pollution abatement technique. *See id.* at 188. The report recognized, as an initial matter, that the Commonwealth Edison Company (CECO) was ''constrained to meet the total load demand'' but that ''load reduction at one plant or even a number of plants is usually feasible by shifting the power demand to other plants in the system.'' *Id.* As a result, the report noted, ''load shifting within the physical limits of the CECO system . . . may be a highly desirable control mechanism.'' *Id.* The report also predicted that ''[i]n the future, it may be possible to form reciprocal agreements to obtain 'pollution abatement' power from neighbor companies during a pollution incident and return this borrowed power at some later date.'' *Id.* at 187.

[605] The EPA notes that affected EGUs are not actually required to collectively reduce generation by the amount represented in the BSER, and may collectively reduce generation by more or less than that amount. Individual affected EGUs are free to choose reduced generation or other means of reducing emissions, as permitted by their state plans, in order to achieve the standards of performance established for them by their states.

including investment in RE and implementation of a broad range of state and utility demand-side EE programs. Commenters added that in some instances, the affected EGUs and states would have no choice but to take the actions in the building blocks because they would not otherwise be able to achieve their emission standards. Commenters also emphasized that with the proposed portfolio approach, the rule would impose federally enforceable requirements on a wide range of entities that do not emit CO_2 and have not previously been subject to CAA regulation. Commenters cite the U.S. Supreme Court's statements in *Utility Air Regulatory Group* v. *EPA (UARG)*[606] that caution an agency against interpreting its statutory authority in a way that ''would bring about an enormous and transformative expansion in [its] regulatory authority without clear congressional authorization,'' and that add, ''When an agency claims to discover in a long-extant statute an unheralded power to regulate 'a significant portion of the American economy,' . . . we typically greet its announcement with a measure of skepticism.''[607] Commenters assert that in this rule, the EPA is taking the actions that the *UARG* opinion cautioned against. For the reasons discussed below, these comments are incorrect and misunderstand fundamental aspects of this rule. In addition, to the extent these comments address either building block 4 or the portfolio approach they are moot, because the EPA is not finalizing those elements of the proposal.

In this rule, the EPA is following the same approach that it uses in any rulemaking under CAA section 111(d), which is designed to regulate the air pollutants from the source category at issue. First, the EPA identifies the BSER to reduce harmful air pollution. Second, based on the BSER, the EPA promulgates emission guidelines, which generally take the form of emission rates applicable to the affected sources. In this case, the EPA is promulgating a uniform CO_2 emission performance rate for steam-generating EGUs and a uniform CO_2 emission performance rate for combustion turbines, and the EPA is translating those rates into a combined emission rate and equivalent mass limit for each state. These emission guidelines serve as the guideposts for state plan requirements. The states, in turn, promulgate standards of performance and, in doing so, retain significant flexibility either to promulgate rate-based emission standards that mirror the emission performance rates in the guidelines, promulgate rate-based emission standards that are equivalent to the emission performance rates in the guidelines, or promulgate equivalent mass-based emission standards. The sources, in turn, are required to comply with their emission standards, and may do so through any means they choose. Alternatively, the state may adopt the state-measures approach, which provides additional flexibility.

Thus, the EPA is not requiring that the affected EGUs take any particular action, such as implementation of the building blocks. Rather, as just explained, the EPA is regulating the affected EGUs' emissions by requiring that the state submit state plans that achieve specified emission performance levels. The states may choose from a wide range of emission limits to impose on their sources, and the sources may choose from a wide range of compliance options to achieve their emission limits. Those options include various means of implementing the building blocks as well as numerous other compliance options, ranging from—depending in part on whether the state imposes a rate-based or mass-based emission limit—implementation of demand-side EE measures to natural gas co-firing.[608]

As some indication of the diverse set of actions we expect to comply with the requirements of this rule, we note that demand-side EE programs, in particular, are expected to be a significant compliance method, in light of their low costs. In addition, the National Association of Clean Air Agencies (NACAA) has issued a report that provides a detailed discussion of 25 approaches to CO_2 reduction in the electricity sector.[609] In addition, we note that the nine RGGI states—Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island and Vermont—have indicated that they intend to maintain their current state programs, which this rule would allow, and there are reports that other states may seek to join RGGI.[610] Similarly, California has indicated that it intends to maintain its current state program, which this rule would allow. Other states could employ the types of methods used in Oregon, Washington, Colorado, or Minnesota, described in the background section of this preamble.

As a practical matter, we expect that for some affected EGUs, implementation of the building blocks will be the most attractive option for compliance. This does not mean, contrary to the adverse comments noted above, that this rule constitutes a redesign of the energy sector. As discussed above, the building blocks meet the criteria to be part of the best system of emission reduction . . . adequately demonstrated. The fact that some sources will implement the building blocks and that this may result in changes in the electricity sector does not mean that the building blocks cannot be considered the BSER under CAA section 111(d).

In this rule, as with all CAA section 111(d) rules, the EPA is not directly regulating any entities. Moreover, the EPA is not finalizing the proposed portfolio approach. Accordingly, the EPA is neither requiring nor authorizing the states to regulate non-affected EGUs in their CAA section 111(d) plans.[611]

Moreover, contrary to adverse comments, this rule does not require the states to adopt a particular type of energy policy or implement particulate types of energy measures. Under this rule, a state may comply with its obligations by adopting the emission standards approach to its state plan and imposing rate-based or mass-based emission standards on its affected EGUs. In this manner, this rule is consistent with prior section 111(d) rulemaking actions, in which the states have complied by promulgating one or both of those types of standards of performance. In this rulemaking, as an alternative, the state may adopt the state measures approach, under which the state could, if it wishes, adopt particular types of energy measures that would lead to reductions in emissions from its EGUs. But again, this rule does not require the state to implement a

[606] 134 S. Ct. 2427 (2014).

[607] *Utility Air Regulatory Group* v. *EPA,* 134 S. Ct. 2427, 2444 (2014) (citations omitted).

[608] In fact, the EPA is expressly precluded from mandating specific controls except in certain limited circumstances. *See* 42 U.S.C. 7411(b)(5). For instance, the EPA is authorized to mandate a particular ''design, equipment, work practice, or operational standard, or combination thereof,'' when it is ''not feasible to prescribe or enforce a standard of performance'' for new sources. 42 U.S.C. 7411(h)(1). CAA section 111(h) also highlights for us that while ''design, equipment, work practice, or operational standards'' may be directly mandated by the EPA, CAA section 111(a)(1) encompasses a broader suite of measures for consideration as the BSER.

[609] NACAA, ''Implementing EPA's Clean Power Plan: A Menu of Options (May 2015), *http://www.4cleanair.org/NACAA_Menu_of_Options*. NACAA describes itself as ''the national, non-partisan, non-profit association of air pollution control agencies in 41 states, the District of Columbia, four territories and 116 metropolitan areas.'' *Id.*

[610] Martinson, Erica, ''Cap and trade lives on through the states,'' Politico (May 27, 2014), *http://www.politico.com/story/2014/05/cap-and-trade-states-107135.html*.

[611] A state may regulate non-EGUs as part of a state measures approach, but those measures would not be federally enforceable.

particular type of energy policy or adopt particular types of energy measures.

It is certainly reasonable to expect that compliance with these air pollution controls will have costs, and those costs will affect the electricity sector by discouraging generation of fossil fuel-fired electricity and encouraging less costly alternative means of generating electricity or reducing demand. But for affected EGUs, air pollution controls necessarily entail costs that affect the electricity sector and, in fact, the entire nation, regardless of what BSER the EPA identifies as the basis for the controls. For example, had some type of add-on control such as CCS been identified as the BSER for coal-fired EGUs, sources that complied by installing that control would incur higher costs. As a result, generation from coal-fired EGUs would be expected to decrease and be replaced at least in part by generation from existing NGCC units and new renewables because those forms of generation would see their competitive positions improved.

This basic fact that EPA regulation of air pollutants from affected EGUs invariably affects the utility sector is well-recognized and in no way indicates that such regulation exceed the EPA's authority. In revising CAA section 111 in the 1977 CAA Amendments, Congress explicitly acknowledged that the EPA's rules under CAA section 111 for EGUs would significantly impact the energy sector.[612] The Courts have recognized that, too. The U.S. Supreme Court, in its 2011 decision that the CAA and the EPA actions it authorizes displace any federal common law right to seek abatement of CO_2 emissions from fossil fuel-fired power plants, emphasized that CAA section 111 authorizes the EPA—which the Court identified as the ''expert agency''—to regulate CO_2 emissions from these sources in a manner that balances ''our Nation's energy needs and the possibility of economic disruption:''

The appropriate amount of regulation in any particular greenhouse gas-producing sector cannot be prescribed in a vacuum: As with other questions of national or international policy, informed assessment of competing interests is required. Along with the environmental benefit potentially achievable, our Nation's energy needs and the possibility of economic disruption must weigh in the balance.

The [CAA] entrusts such complex balancing to EPA in the first instance, in combination with state regulators. Each ''standard of performance'' EPA sets must ''tak[e] into account the cost of achieving [emissions] reduction and any nonair quality health and environmental impact and energy requirements.'' § 7411(a)(1), (b)(1)(B), (d)(1); see also 40 CFR 60.24(f) (EPA may permit state plans to deviate from generally applicable emissions standards upon demonstration that costs are ''[u]nreasonable''). EPA may ''distinguish among classes, types, and sizes'' of stationary sources in apportioning responsibility for emissions reductions. § 7411(b)(2), (d); see also 40 CFR 60.22(b)(5). And the agency may waive compliance with emission limits to permit a facility to test drive an ''innovative technological system'' that has ''not [yet] been adequately demonstrated.'' § 7411(j)(1)(A). The Act envisions extensive cooperation between federal and state authorities, see § 7401(a), (b), generally permitting each state to take the first cut at determining how best to achieve EPA emissions standards within its domain, see § 7411(c)(1), (d)(1)–(2).

It is altogether fitting that Congress designated an expert agency, here, EPA, as best suited to serve as primary regulator of greenhouse gas emissions. The expert agency is surely better equipped to do the job than individual district judges issuing ad hoc, case-by-case injunctions.[613]

Similarly, the D.C. Circuit, in its 1981 decision upholding the EPA's rules to reduce SO_2 emissions from new coal-fired EGUs under the version of CAA section 111(b) adopted in the 1977 CAA Amendments, stated:

[S]ection 111 most reasonably seems to require that EPA identify the emission levels that are ''achievable'' with ''adequately demonstrated technology.'' After EPA makes this determination, it must exercise its discretion to choose an achievable emission level which represents the best balance of economic, environmental, and energy considerations. It follows that to exercise this discretion EPA must examine the effects of technology on the grand scale in order to decide which level of control is best. . . . The standard is, after all, a national standard with long-term effects.[614]

The D.C. Circuit added: ''Regulations such as those involved here demand a careful weighing of cost, environmental, and energy considerations. They also have broad implications for national economic policy.''[615] This rule has ''economic, environmental, and energy'' impacts, as Congress and the Courts expect in a CAA section 111 rule, but those impacts do not mean that the EPA is precluded from promulgating the rule.

As noted above, in this rule, to control CO_2 emissions from affected EGUs, the EPA first considered more traditional air pollution control measures, including supply-side efficiency improvements, fuel-switching (for CO_2 emissions, that entails co-firing with natural gas), and add-on controls (for CO_2 emissions, that entails CCS). However, it became apparent that even if the EPA could have finalized those controls as the BSER[616] and established the same uniform CO_2 emission performance rates, the affected EGUs would rely on less expensive ways to achieve their emission limits. Specifically, instead of relying on co-firing and CCS, the affected EGUs generally would replace their generation with lower- or zero-emitting generation—the measures in building blocks 2 and 3—because those measures are significantly less expensive and already well-established as pollution control measures. Indeed, some affected EGUs have stated that while they oppose including in the BSER generation shifts to lower- or zero-emitting sources (or, as proposed, demand-side EE), they request that those measures be available for compliance, which indicates their

[612] The D.C. Circuit acknowledged this legislative history in *Sierra Club* v. *EPA,* 657 F.2d 298, 331 (D.C. Cir. 1981). There, the Court stated:

[T]he Reports from both Houses on the Senate and House bills illustrate very clearly that Congress itself was using a long-term lens with a broad focus on future costs, environmental and energy effects of different technological systems when it discussed section 111. [Citing S. Rep. No. 95–127, 95th Cong., 1st Sess. (1977), 3 Legis. Hist. 1371; H.R. Rep. No. 95–294, 95th Cong., 1st Sess. 188 (1977), 4 Legis. Hist. 2465.]

[613] *American Electric Power Co.* v. *Connecticut,* 131 S. Ct. 2527, 2539–40 (2011).

[614] *Sierra Club* v. *EPA,* 657 F.2d 298, 330 (D.C. Cir. 1981).

[615] *Sierra Club* v. *EPA,* 657 F.2d 298, 406 (D.C. Cir. 1981). The Court supported this statement with a lengthy quotation from a scholarly article, which stated, in part:

Consider for a moment the chain of collective decisions and their effects just in the case of electric utilities. Petroleum imports can be conserved by switching from oil-fired to coal-fired generation. But barring other measures, burning high-sulfur Eastern coal substantially increases pollution. Sulfur can be ''scrubbed'' from coal smoke in the stack, but at a heavy cost, with devices that turn out huge volumes of sulfur wastes that must be disposed of and about whose reliability there is some question. Intermittent control techniques (installing high smokestacks and switching off burners when meteorological conditions are adverse) can, at lower cost, reduce local concentrations of sulfur oxides in the air, but cannot cope with the growing problem of sulfates and widespread acid rainfall. Use of low-sulfur Western coal would avoid many of these problems, but this coal is obtained by strip mining. Strip-mining reclamation is possible, but substantially hindered in large areas of the West by lack of rainfall. Moreover, in some coal-rich areas the coal beds form the underground aquifer and their removal could wreck adjacent farming or ranching economies. Large coal-burning plants might be located in remote areas far from highly populated urban centers in order to minimize the human effects of pollution. But such areas are among the few left that are unspoiled by pollution and both environmentalists and the residents (relatively few in number compared with those in metropolitan localities but large among the voting population in the particular states) strongly object to this policy. *Id.* at 406 n. 526.

[616] For the reasons explained, we did not finalize those measures because significantly less expensive control measures—building blocks 2 and 3—are available for these affected EGUs.

interest in implementing those measures.[617]

We expect that many sources will choose to comply with their emission limits through the measures in building blocks 2 and 3, but contrary to the assertions of some commenters, this will not result in unprecedented and fundamental alterations to the energy sector. As discussed above, Congress relied on the same measures as those the EPA is including in building blocks 2 and 3 as essential parts of the basis for the Title IV emission limits for fossil fuel-fired EGUs, and the EPA did the same for the emission limits in various rules for those same sources.

In addition, reliance on the measures in building blocks 2 and 3 is fully consistent with the recent changes and current trends in electricity generation, and as a result, would by no means entail fundamental redirection of the energy sector. As indicated in the RIA for this rule, we expect that the main impact of this rule on the nation's mix of generation will be to reduce coal-fired generation, but in an amount and by a rate that is consistent with recent historical declines in coal-fired generation. Specifically, from approximately 2005 to 2014, coal-fired generation declined at a rate that was greater than the rate of reduced coal-fired generation that we expect to result from this rulemaking from 2015 to 2030. In addition, under this rule, the trends for all other types of generation, including natural gas-fired generation, nuclear generation, and renewable generation, will remain generally consistent with what their trends would be in the absence of this rule. In addition, this rule is expected to result in increases in demand-side EE.

In addition, contrary to claims of some commenters, in this rule, the EPA is not attempting to expand its authorities by attempting to expand the jurisdiction of the CAA to previously unregulated sectors of the economy, in contravention of the *UARG* decision. In *UARG,* the U.S. Supreme Court struck down the EPA's interpretation of the PSD provisions of the CAA because the interpretation had the effect of applying the PSD requirements to large numbers of small sources that previously had not been subject to PSD, and because, according to the Court, the EPA acknowledged that Congress did not intend that such sources be subject to the PSD requirements.[618] Commenters appear to interpret this decision to preclude the EPA from including at least building block 3 in the BSER because it includes measures that involve entities (such as RE developers) that do not emit CO_2 and have not previously been subject to the CAA. However, in this rule, the EPA is not attempting to subject any entity other than the affected EGUs in the source category to CAA section 111 requirements. As discussed below, the EPA is not finalizing the proposed portfolio approach, under which states were authorized to include, in their CAA section 111(d) state plans, federally enforceable requirements on entities other than affected EGUs. Thus, as noted above, this final rule does not require or authorize the states to include entities other than affected EGUs in their CAA section 111(d) state plans, and as a result, those entities will not come under CAA jurisdiction[619] and the parts of the economy that they represent will not be regulated by the EPA.

7. Relative Stringency of Requirements for Existing Sources and New, Modified, and Reconstructed Sources

Commenters also objected that the proposed CAA section 111(d) standards are more stringent than the standards for new, modified or reconstructed sources, and they assert that setting CAA section 111(d) standards that are more stringent than CAA section 111(b) standards would be illogical, contrary to precedent, contrary to the intent of the remaining useful life exception, and arbitrary and capricious.[620] We disagree with these comments. Comparing the control requirements of the two sets of rules, CAA section 111(d) and 111(b), is an ''apples-to-oranges'' comparison and, as a result, it is not possible—and it is overly simplistic—to conclude that the CAA section 111(d) requirements are more stringent than the CAA section 111(b) requirements.

Most importantly, the two sets of rules become applicable at different points in time and have significantly different compliance periods. The CAA section 111(b) rule becomes applicable for new, modified and reconstructed sources immediately upon construction, modification, or reconstruction and, in fact, by operation of CAA section 111(e) and (a)(2), new, modified, or reconstructed sources that commenced construction prior to the effective date of the CAA section 111(b) rule must also be in compliance upon the effective date of the rule. In contrast, the requirements under the CAA section 111(d) rule do not become applicable to existing affected EGUs until seven years after promulgation of the rule, when the interim compliance period begins in 2022, and the final compliance period does not begin until 2030. Moreover, the compliance period for the interim requirements is eight years. This later applicability date and longer compliance period for existing sources accommodates a requirement that, on average, those sources have a lower nominal emission limit than the standards for new or modified sources, which those latter sources must comply with immediately.

In addition, the timetables for compliance with the CAA section 111(b) and 111(d) rules should be considered in light of the 8-year review schedule required for CAA section 111(b) rules under CAA section 111(b)(1)(B). Under CAA section 111(b)(1)(B), the EPA is required to ''review and, if appropriate, revise'' the CAA section 111(b) standards ''at least every 8 years.'' This provision obligates the EPA to review the CAA section 111(b) rule for CO_2 emissions from new, modified, and reconstructed power plants by the year 2023. That mandatory review will reassess the BSER to determine the appropriate stringency for emission standards for new, modified, and reconstructed sources into the future. Therefore, for present purposes of comparing the stringency of the CAA section 111(b) and 111(d) rules, the year 2023 presents an important point of comparison.

Specifically, as noted above, the CAA section 111(b) standards apply to new, modified and reconstructed sources beginning in 2015, while the CAA section 111(d) rule does not take effect until 2022, which happens to fall on the cusp of the 8-year review for the CAA section 111(b) standards.

Even after the section 111(d) rule takes effect in 2022, the flexibility that this rule offers the states has important implications for its stringency and for any comparison to the CAA section 111(b) rule. Although the requirements for the CAA section 111(d) rule begin in 2022, they are phased in, in a flexible manner, over the 2022–2030 period. That is, states are required to meet interim goals for the 2022–2029 period by 2029, and the final goals by 2030, but states are not required to impose requirements on their sources that take

[617] See the proposal for this rule, 79 FR at 34888 (''during the public outreach sessions, stakeholders generally recommended that state plans be authorized to rely on, and that affected sources be authorized to implement, re-dispatch, renewable energy measures, and demand-side energy efficiency measures in order to meet states' and sources' emission reduction obligations.'').

[618] *Util. Air Reg. Group* v. *EPA,* 134 S. Ct. 2427, 2443 (2014).

[619] States may regulate non-affected EGUs through a state measures approach, but those regulations would not be federally enforceable.

[620] ACC et al. (Associations) comments at 40, Luminant comments at 89.

effect in 2022. In fact, states may, if they prefer, impose business-as-usual emission standards on their sources that do not require emission reductions in 2022 and apply emission standards on their sources that do require emission reductions and that take effect no earlier than 2023. Moreover, because emission standards may have an annual compliance period, the states may allow their sources to delay having to comply with any emission reduction requirements until the end of 2023.[621]

Therefore, while the CAA section 111(b) standards apply to new, modified, and reconstructed sources beginning in 2015, the CAA section 111(d) standards may not apply to existing sources until 2023. As a result, by 2023—the year that the CAA section 111(b) standards are required to be reviewed for possible revision—affected EGUs subject to the CAA section 111(d) standards may remain uncontrolled. Under those circumstances, the CAA section 111(d) rule cannot be said to be more stringent than the CAA section 111(b) rule.[622]

Another reason why the section 111(d) rule cannot be said to be more stringent than the section 111(b) rule is that for any individual source, the section 111(d) rule is applied more flexibly and includes more flexible means of compliance. Whereas the CAA section 111(b) rule entails an emission rate that each affected EGU must meet on a 12-month (rolling) basis, the CAA section 111(d) is more flexible. For example, states may adopt the state measures approach and refrain from imposing any requirements on their affected EGUs. In addition, under the CAA section 111(d) rule, sources have more flexible means of compliance. For an emission standards approach, depending on the form of the state requirements (mass-based or rate-based), the state may be expected to authorize trading of mass-based emission allowances or rate-based emission credits, and in addition, the purchase of ERCs. These flexibilities are not included in the CAA section 111(b) rule, rather, as noted, each new, modified, and reconstructed EGU must individually meet its emission standard on a 12-month (rolling) basis. The EPA has frequently required that sources meet a more stringent nominal limit when they are allowed compliance flexibility, particularly, the opportunity to trade.[623] In addition, states have the discretion to allow their sources to meet emission standards over a longer time period. This distinction between the two rules is another reason why the CAA section 111(d) rule cannot be said to be more stringent in fact than the CAA section 111(b) rule.

There are other reasons why the CAA section 111(d) rule cannot be said to be more stringent. With respect to the CAA section 111(d) and 111(b) rules for existing and new NGCC units, we note the following: As explained in the CAA section 111(b) preamble, the standard for new NGCC units is designed to accommodate a wide range of unit types, including small units and rapid-start units, which are a small part of the expected new NGCC generation capacity. As such, the CAA section 111(b) standard (1,000 lb CO_2/MWh gross, which equates to 1,030 lb CO_2/MWh net) will not constrain the emissions of the great majority of expected new NGCC generation capacity, which is expected to consist of larger base load units (with a capacity of 100 MW or greater) that are not intended to cycle frequently. Their initial emissions are expected to be below 800 lb. CO_2/MWh gross, their emissions over time may be somewhat higher due to equipment deterioration, and as a result, their PSD permits are expected to include emission limits at approximately the 800 lb. CO_2/MWh gross level. A very small amount of the new NGCC generation is expected to be small units (with a capacity of approximately 25 MW) or rapid-start units. Their initial emissions are expected to be approximately 950 lb. CO_2/MWh gross, their emissions over time are expected to be somewhat higher due to equipment deterioration, and it these units that the standard of 1,000 lb. CO_2/MWh gross is designed to constrain.[624] As a result, the 1,000 lb. CO_2/MWh gross limit applies to all new NGCC units, including the great majority of the expected new capacity consisting of larger, non-rapid start units, even though, as just noted, the great majority of the units are expected to emit at significantly lower emission rates. The CAA section 111(d) standard for existing sources, in contrast, is generally expected to constrain existing NGCC units on average. Moreover, very little of the existing NGCC generation includes small units or, in particular, rapid-start units because the latter are a recently developed technology. To some extent, the same is true for the 111(b) standard for reconstructed NGCC units. The average NGCC rate was approximately 850 lb CO_2/MWh gross in 2014 and, as a result, most sources are emitting below the CAA section 111(b) standard for reconstructed sources. For these reasons, too, the CAA section 111(b) standards for new and reconstructed NGCC units cannot be compared to the 111(d) standards for existing NGCC units.[625]

Moreover, even if commenters were correct that the CAA section 111(d) requirements for existing sources are more stringent than the CAA section 111(b) requirements for new sources, that would not, by itself, call into question the reasonableness of either standard. The stringency of the requirements for each source subcategory is, of course, a direct function of the BSER identified for that source subcategory. In this rulemaking, we explain the basis for the BSER for existing sources, and why we do not include certain measures, such as CCS; and in the CAA section 111(b) rulemaking, we explain the basis for the

[621] A state that chooses to allow its sources to remain uncontrolled through 2023 would still be able to meet its interim goal by 2029, although it would need to impose more stringent requirements on its sources over the 2024–2029 period than it would if it had imposed requirements beginning in 2022. It should also be noted that in fact, most states could allow their sources to remain uncontrolled for 2022 and 2023, and require controls beginning in 2024, and still be able to meet their interim goal.

[622] In addition, because the section 111(d) requirements are phased in, states may choose to apply a gradual phase-in of the reductions. This means that the nominal emission rates for section 111(d) sources would be significantly less stringent for the first several years of the compliance period. We estimate that if states choose to impose the section 111(d) requirements in a proportional amount each year, beginning in 2022, the requirements for steam generators by 2022 would result in an average emission performance rate of 1,741 lb. CO_2/MWh net and by 2023, an average emission rate of 1,681 lb. CO_2/MWh net (In 2030, the rate falls to 1,305 lb. CO_2/MWh net.) For existing NGCC units, if states choose to implement the section 111(d) requirements proportionally, in 2022, the average rate would be 898 lb. CO_2/MWh net, and in 2023 it would be 877 lb. CO_2/MWh net. (In 2030, this rate falls to 771 lb. CO_2/MWh net.)

[623] *See, e.g.,* EPA, ''Improving Air Quality with Economic Incentive Programs,'' EPA–452/R–01–001, at 82 (2001) (requiring that Economic Incentive Programs show an environmental benefit, such as ''reducing emission reductions generated by program participants by at least 10 percent''), *available athttp://www.epa.gov/airquality/advance/pdfs/eipfin.pdf*; ''Economic Incentive Program Rules: Final Rule,'' 59 FR 16690 (April 7, 1994) (same); ''Certification Programs for Banking and Trading of NO_X and PM Credits for Heavy-Duty Engines: Final Rule,'' 55 FR 30584 (July 26, 1990) (requiring that for programs for banking and trading of NO_X and PM credits for gasoline, diesel and methanol powered engines, all trading and banking of credits must be subject to a 20 percent discount ''as an added assurance that the incentives created by the program will not only have no adverse environmental impact but also provide an environmental benefit.'').

[624] As explained in the 111(b) preamble, any attempt to subcategorize and assign a lower emission limit to larger, non-rapid start NGCC units could cause market distortions.

[625] The section 111(b) standards for modified and reconstructed steam generation units are generally lower than the emission rates of existing stream generation units, but for the reasons explained earlier, those standards cannot be compared to the section 111(d) standards for existing steam generation units.

BSER for new sources, and why we do not include certain measures, such as the building blocks. As long as the BSER determination is reasonable and the resulting emission limits meet other applicable requirements, those emission limits are valid, even if the one for new sources is less stringent than the one for existing sources. No provision in section 111, nor any statement in its legislative history, nor any of its case law, indicates that the standards for new sources must be more stringent than the standards for existing sources.

C. Building Block 1—Efficiency Improvements at Affected Coal-Fired Steam EGUs

The first category of approaches to reducing CO_2 emissions at affected fossil fuel-fired EGUs consists of measures that improve heat rate at coal-fired steam EGUs. Heat rate improvements are changes implemented at an EGU that increase the efficiency with which the EGU converts fuel energy to electric energy, thereby reducing the amount of fuel needed to produce the same amount of electricity and consequently lowering the amount of CO_2 produced as a byproduct of fuel combustion. Heat rate improvements yield important economic benefits to affected EGUs by reducing their fuel costs.

An EGU's heat rate is the amount of fuel energy input needed (Btu, higher heating value basis) to produce 1 kWh of net electrical energy output.[626] In 2012, the generation-weighted average annual heat rate of the 884 coal-fired EGUs included in EPA's building block 1 analysis was approximately 9,732 Btu per gross kWh.[627] Because an EGU's CO_2 emissions are driven primarily by the amount of fuel consumed, improving (*i.e.,* decreasing) heat rate at a coal-fired EGU inherently reduces the carbon-intensity of generation.

As discussed above in section V.A and in the June 2014 proposal,[628] it is critical to recognize that affected coal-fired EGUs operate in the context of the integrated electricity system. Because of this reality, applying building block 1 in isolation can result in a ''rebound effect'' that undermines the emissions reductions otherwise achieved by heat rate improvements. As already noted, the building block 1 measures described below cannot by themselves constitute the BSER because the quantity of emission reductions achieved—which is a factor that the courts have required EPA to consider in determining the BSER—would be of insufficient magnitude in the context of this pollutant and this industry. The potential rebound effect, if it occurred, would exacerbate the insufficiency of the emission reductions. However, applying building block 1 in combination with other building blocks can address this concern for the reasons stated in section V.A.4.

We conducted several analyses to assess the potential for heat rate improvements from the coal-fired EGU fleet. As in the proposal, we employed a unit-specific approach that compared each EGU's performance against its own historical performance in lieu of directly comparing an EGU's performance against other EGUs with similar characteristics. Accordingly, as described below, our method effectively controls for the characteristics and factors of an EGU that typically remain constant over time (*e.g.,* a unit is unlikely to dramatically increase or decrease in size). Our methodology for determining the amount of heat rate improvement appropriately included in the BSER as building block 1 is discussed in the next section, below.

1. Summary of Measures Comprising the BSER in Building Block 1

a. *Measures under building block 1—heat rate improvements.*

In finalizing the building block 1 portion of this rule, we considered over a thousand individual comments from the public, including individual EGUs and state agencies, on heat rate improvement, which are discussed below and also in the responses to comments document and the GHG Mitigation Measures TSD for the CPP Final Rule. Based on these public comments, we have refined the statistical analyses used in the proposal to identify the potential heat rate improvement that can be achieved on average by affected coal-fired EGUs.

In the proposal, we used two approaches to analyze the variability of an EGU's gross heat rate using a robust dataset comprised of 11 years of hourly gross heat rate data for 884 coal-fired EGUs—over 11 million hours of data collected between 2002 and 2012. The foundation of our first approach was an analysis of the variability of each EGU's gross heat rate, which was accomplished in large part by grouping each EGU's hourly data by similar ambient temperature and capacity factor (*i.e.,* hourly operating level as a percentage of nameplate capacity) conditions. The second approach analyzed the difference between an EGU's average gross heat rate and its best historical gross heat rate performance. We proposed that, on a nationwide basis, affected coal-fired EGUs should be able to achieve 6-percent heat rate improvement: 4-percent improvement from best practices, and an additional 2-percent improvement from equipment upgrades.

We received many comments asserting that the 11-year dataset we had used to determine the 4-percent best practices figure likely reflected some portion of the 2-percent equipment upgrades figure we had separately identified. Accordingly, these commenters claim that the EPA double-counted equipment upgrades in arriving at the full estimate of 6-percent heat rate improvement. Commenters also noted the difficulty, in some cases, of determining whether a heat rate improvement measure is an ''equipment upgrade'' or ''best practice,'' such as optimizing soot blowing with intelligent systems, using CO monitors for optimizing combustion, or applying air heater and duct leakage controls.

As noted below in sections V.C.1.b and V.C.3, the EPA acknowledges that some equipment upgrades implemented by EGUs during the 11-year study period are reflected in the hourly heat rate data. Therefore, we made two refinements to our analyses of heat rate improvement potential. First, we refined our statistical approaches to use each EGU's gross heat rate from 2012—the final year of the 11-year study period—as the baseline for calculating heat rate improvement potential. By comparing each EGU's best historical gross heat rate with its 2012 gross heat rate, our analyses account for the enduring effects on heat rate of any equipment upgrades or best practices that an EGU implemented during the study period. Heat rate improvement measures that an EGU maintains in 2012 are reflected in that baseline, and thus are not treated as evidence that the EGU can further improve heat rate. Additionally, in part because of limitations on the information available to us regarding which equipment upgrades have been or could be implemented at individual EGUs, as well concerns about double-counting, we have conservatively decided not to add a separate equipment upgrade component to our estimate of heat rate improvement potential. Nonetheless, we remain confident that additional equipment upgrades

[626] Typically, the units of measure used for heat rate (*e.g.,* Btu/kWh-net) indicate whether a given value is based on the gross output or net output. Net heat rate is always higher than gross heat rate; in coal-steam units, net heat rate can be 5–10% higher than gross heat rate.

[627] Similarly, within each interconnection, the generation-weighted average annual heat rates for those coal-fired EGUs in our study population were 9,700 Btu per gross kWh (Eastern); 9,888 Btu per gross kWh (Western); and 9,789 Btu per gross kWh (Texas).

[628] *See, e.g.,* 79 FR 34830, 34859 (June 18, 2014).

(including measures that are unambiguously equipment upgrades, such as turbine overhauls) are possible at many coal-fired EGUs, as supported by numerous commenters, the Sargent & Lundy study [629] (S&L) and other industry reports and studies. Many of these reports and studies are referenced in the TSD developed for the proposed rule, as well as in the GHG Mitigation Measures TSD supporting the final CPP.

Several commenters criticized the fact that the proposal assessed potential heat rate improvement on a nationwide basis. These commenters suggested instead that we narrow the geographic scope of our analysis, generally identifying a state-by-state approach as a preferred alternative. In light of commenters' concerns about using a single nationwide approach, as well as for reasons described in Section V.A and elsewhere in this preamble, the final rule assesses potential heat rate improvement regionally, within the Eastern, Western and Texas Interconnections.[630]

For the final rule, we performed several analyses to determine what heat rate improvement was achievable in each interconnection from best practices and equipment upgrades. As in the proposal, these analyses used the 11-year dataset of EGU hourly gross heat rate data from 2002 to 2012. As discussed further in the GHG Mitigation Measures TSD, our reliance on these gross heat rate data was reasonable given that (1) these data are the only comprehensive data available to the EPA, and (2) heat rate is proportional to CO_2 emission rate.

As in the proposal, we used more than one analytical method to evaluate the opportunity for EGUs to reduce their CO_2 emissions through heat rate improvements. Our final methodology uses three different analytical approaches based on refinements of the two approaches described at the proposal stage. We call these final approaches: (1) The ''efficiency and consistency improvements under similar conditions'' approach; (2) the ''best historical performance'' approach; and (3) the ''best historical performance under similar conditions'' approach. As described below and in the GHG Mitigation Measures TSD, each approach provides an independently reasonable way to estimate the potential for heat rate improvements by EGUs in each region. However, rather than select a potential heat rate improvement value supported by one or only some of these independently reasonable analytical approaches, we conservatively based our final determination for each region on the value for that region supported by all three approaches.

The ''efficiency and consistency improvements under similar conditions'' approach is a slight refinement of an approach discussed at length in the proposal. As in the proposal, we distributed each hour of gross heat rate data for each EGU into a matrix comprised of 168 bins, based on the ambient temperature and hourly capacity factor of the EGU at the time that hour of gross heat rate data was generated. Each bin represented a 10-degree Fahrenheit (°F) range in ambient temperature (from −20 °F to greater than 110 °F), and a 10-percent range in capacity factor (from 0 percent to greater than 110 percent [631]). Thus, for example, one bin would contain all of an EGU's hourly gross heat rate data generated during the 11-year study period while that EGU was operating at 80- to 89-percent capacity while ambient temperatures were between 70 °F and 79 °F.

As we explained at proposal and as discussed further in the GHG Mitigation Measures TSD, ambient temperature and hourly capacity factor are important conditions that influence heat rate at individual EGUs. By separating the EGU-specific data into bins based on these variables, and only directly comparing data within a bin, we were largely able to control for the influence of those variables on an EGU's heat rate. Accordingly, having controlled for these two external factors, and having already controlled for unit-specific factors affecting heat rate by analyzing the data for each EGU in isolation, we are confident that the remaining variation in each bin's data was primarily driven by factors under the EGU operator's control.

After allocating an individual EGU's data across the bins, we next established a benchmark for each bin based on the best hourly gross heat rate accounting for outliers (*i.e.,* we set the benchmark at the 10th percentile hourly gross heat rate value) during any consecutive two-year period.[632] We compared the hourly gross heat rate data within each bin to the EGU's benchmark value. Similar to the proposal, within each bin we assessed the effect on heat rate of improving the consistency of that EGU by reducing hourly gross heat rate values that were greater than the benchmark by a percentage of the distance between each of those higher hourly values and the benchmark.[633] We refer to this percentage improvement value as the ''consistency factor,'' because applying it results in values for heat rate that are more consistent with the EGU's benchmark for that bin. In our proposal we evaluated the heat rate improvement that would result from applying consistency factors of 10, 20, 30, 40 and 50 percent of the distance between those less-efficient hourly gross heat rate values and the benchmark; using engineering judgment, we selected a consistency factor of 30 percent, which produced results comparable to those obtained using other approaches for analyzing heat rate. For our final analysis under this approach, we refined the consistency factor based on a statistical assessment of the overall variability of heat rate in that EGU's region, as described in the GHG Mitigation Measures TSD.[634] As in the proposal, we applied the consistency factor to each bin of each EGU's hourly gross heat rate data, and averaged the result across all bins in that EGU's matrix. The net result was an improved gross heat rate reflecting what that EGU would have achieved between 2002 and 2012 if, under certain ambient temperature and capacity factor conditions, the EGU had improved its gross heat rate during less-efficient hours to be slightly more consistent with the relevant benchmark value. We then compared the improved gross heat rate for each EGU to its actual 2012 historical average gross heat rate. We

[629] Sargent and Lundy 2009, Coal-Fired Power Plant Heat Rate Reductions, SL–009597, Final Report, January 2009, *available at: http://www.epa.gov/airmarkets/documents/ipm/coalfired.pdf.*

[630] The geographic area within the Texas Interconnection generally corresponds to the portion of the state of Texas covered by ERCOT (the Electric Reliability Council of Texas). Additional portions of the state of Texas are located within the Eastern and Western Interconnections.

[631] Because an EGU's rated nameplate capacity is based on a maximum continuous rating, EGUs may operate for periods of time ''over'' 100 percent of their capacity factor. The EPA's dataset of hourly operating data reflected some such instances.

[632] As described below, we also conducted this regionalized approach using a benchmark based on the best hourly gross heat rate accounting for outliers during any one-year period. See the GHG Mitigation Measures TSD supporting the final CPP for more details.

[633] In the proposal, we used heat input values rather than gross heat rate values. See the GHG Mitigation Measures TSD supporting the final CPP for more details.

[634] For the Eastern Interconnection, the consistency factor is 38.1 percent. For the Western Interconnection, the consistency factor is 38.4 percent. For the Texas Interconnection, the consistency factor is 37.1 percent. Conducting this analysis on a nationwide basis would have resulted in application of a consistency factor of 38.2 percent. As described below, we also conducted this regionalized approach using consistency factors determined based on one-year figures. See the GHG Mitigation Measures TSD supporting the final CPP for more details.

chose 2012 as the year of comparison because 2012 was the latest year for which the EPA had data at the time of the proposal, and because using the most recent data reflects the EGU's current operating level and accounts for improvements the EGU may have undertaken over the 11-year study period.

Applying this procedure to all units in our database and averaging the generation-weighted results, we determined that it would be reasonable to conclude that, through application of best practices and equipment upgrades, EGUs on average are at least capable of reducing their CO_2 emissions by improving heat rate 4.3 percent in the Eastern Interconnection, 2.1 percent in the Western Interconnection, and 2.3 percent in the Texas Interconnection.[635]

In addition to the statistical approach described above, we employed a ''best historical performance'' approach refined from the proposal, which compared each EGU's best two-year rolling average gross heat rate to that EGU's 2012 average annual gross heat rate.[636] We then calculated the differences across all EGUs in a region to determine the potential heat rate improvement that would result if, in 2012, each EGU had performed at the best two-year rolling average gross heat rate that the EGU achieved between 2002 and 2012. Under this analysis of historical gross heat rate, we determined that it would be reasonable to conclude that the average heat rate improvement potential from best practices and equipment upgrades is at least 4.9 percent in the Eastern Interconnection, 2.6 percent in the Western Interconnection and 3.1 percent in the Texas Interconnection.[637]

Finally, we employed the ''best historical performance under similar conditions'' approach, which combines aspects of the other two approaches. First, as with the ''efficiency and consistency improvements under similar conditions approach,'' we grouped hourly data for each EGU by ambient temperature conditions and hourly capacity factor. Next, we calculated each EGU's best two-year gross heat rate for each of the 168 ambient temperature-capacity factor bins.[638] Similar to the ''best historical performance'' approach, to calculate the potential heat rate improvement, the EPA then compared each EGU's 2012 gross heat rate for each of the ambient temperature-capacity factor bins to the EGU's best two-year gross heat rate for the corresponding bin. Accounting for differences in ambient temperature and capacity factor, we determined that under this analytical approach the average heat rate improvement potential from best practices and equipment upgrades was at least 5.3 percent in the Eastern Interconnection, 3.1 percent in the Western Interconnection and 3.5 percent in the Texas Interconnection.[639]

As in the proposal, we additionally analyzed the data with our analytical approaches using one-year averaging periods in place of the two-year averaging periods described above.[640] However, because our conservative overall methodology adopts the lowest value that is identified for a region by any of our reasonable analytical approaches, the inherently less conservative results obtained with one-year averaging periods (reproduced below) could not influence the outcome of our methodology as a whole. Overall, applying these three analytical approaches resulted in six heat rate improvement values generated for each region, each of which represents a reasonable estimate of the potential for heat rate improvements by EGUs in that region. Those values ranged from 4.3 to 6.9 percent in the Eastern Interconnection, from 2.1 to 4.7 percent in the Western Interconnection, and from 2.3 to 4.9 percent in the Texas Interconnection. In all three regions, the most conservative values were generated using the ''efficiency and consistency improvements under similar conditions'' approach with two-year averaging periods and consistency factors. As shown in Table 6, the values produced by that approach were the minimum values for each region produced by any of the three approaches:

TABLE 6—HEAT RATE IMPROVEMENT POTENTIAL BY REGION AND AVERAGING PERIOD

Analytical approach	Heat rate improvement potential (percent) by region and averaging period					
	Western		Texas		Eastern	
	1 year	2 year	1 year	2 year	1 year	2 year
Efficiency and consistency improvements under similar conditions	3.5	2.1	3.7	2.3	5.6	4.3
Best historical performance	4.1	2.6	4.2	3.1	6.3	4.9
Best historical performance under similar conditions	4.7	3.1	4.9	3.5	6.9	5.3

Accordingly, we have concluded that a well-supported and conservative estimate of the potential heat rate improvements (and accompanying reductions in CO_2 emission rates) that EGUs can achieve on average through best practices and equipment upgrades is a 4.3-percent improvement in the Eastern Interconnection, a 2.1-percent improvement in the Western Interconnection and a 2.3-percent improvement in the Texas Interconnection. The decision to use these values as the building block 1 potential in each region is based on the weight of evidence that these are conservative values; for each region, each of the three analytical approaches in our methodology supports our determination that the heat rate improvement value we selected is

[635] Conducting this analysis on a nationwide basis would have resulted in a finding that EGUs nationwide are capable on average of reducing their CO_2 emissions by improving heat rate 4.0 percent. See the table in this section and the GHG Mitigation Measures TSD for the results of this approach using benchmarks and consistency factors based on one-year averages.

[636] As described below, we also conducted this regionalized approach using each EGU's best one-year rolling average. See the GHG Mitigation Measures TSD supporting the final CPP for more details.

[637] Conducting this approach on a nationwide basis would have resulted in a finding that EGUs nationwide are capable on average of reducing their CO_2 emissions by improving heat rate 4.6 percent. As described below, we also conducted this regionalized approach using one-year averages. See the GHG Mitigation Measures TSD supporting the final CPP for more details.

[638] As described below, we also conducted this approach using one-year averages for each EGU instead of two-year averages. See the GHG Mitigation Measures TSD supporting the final CPP for more details.

[639] Conducting this approach on a nationwide basis would have resulted in a finding that EGUs nationwide are capable on average of reducing their CO_2 emissions by improving heat rate 5.0 percent.

[640] The GHG Mitigation Measures TSD describes in more detail our rationale for using one- and two-year averaging periods in our analytical approaches and methodology as a whole.

achievable. Taken individually, each approach provides an independently reasonable estimate of the potential for heat rate improvement. Furthermore, as described in the GHG Mitigation Measures TSD, these approaches are conservative on even an individual basis because they do not account for the full extent of heat rate improvements available through additional equipment upgrades and best practices. Some EGUs may have faced difficulties achieving significant heat rate improvement in the past and EGU owners may feel they face challenges in the future. Nevertheless, our methodology as a whole indicates that, on average, coal-fired EGUs can at least achieve the percentage heat rate improvement selected for their region through application of best practices and some of the available equipment upgrades. A more detailed discussion of the EPA's analysis in determining the heat rate improvement potential for existing coal-fired EGUs may be found in the GHG Mitigation Measures TSD supporting the final CPP.

No affected coal-fired EGU is specifically required to improve heat rate by any amount as a result of this rule. Rather, as described in section VI, the potential for heat rate improvement is used to determine a CO_2 emission performance rate. Those affected EGUs that have done the most to reduce their heat rate will tend to be closer to that CO_2 emission rate. In this sense, our approach to determining potential CO_2 reductions through heat rate improvements is similar to the way EPA ordinarily approaches standards of performance.[641]

In this final analysis, we do not delineate what proportion of the potential heat rate improvement can be expected from equipment upgrades versus best practices;[642] only that these heat rate improvements are achievable in the regions through a combination of these methods. As discussed in section V.C.3 below, we believe that a single heat rate improvement goal for each region incorporating both best practices and upgrades, based on the 11 years of hourly heat rate data for 884 coal-fired EGUs available to the EPA, is a reasonable approach that is supported by our analysis, and is particularly conservative given that it does not account for the full range of heat rate improvements achievable through additional equipment upgrades and best practices.

The performance rates quantified in section VI, below, reflect the region-specific values for heat rate improvement. Although the performance rates are based on the least stringent overall performance rate determined to be reasonable for any region, and are thus based in part on the percentage heat rate improvement identified for the region, this rule does not itself require any specific EGU to implement measures resulting in a specific percentage heat rate improvement. Rather, the percentage heat rate improvement value is merely reflected in the CO_2 emission performance rates and corresponding mass-based and rate-based state goals. Each state has the flexibility to develop a plan that achieves those CO_2 performance rates or emission goals by assigning the emission standards the state considers appropriate to its affected coal-fired EGUs. Similarly, depending on the content of the applicable plan, affected EGUs may achieve their emission standards through use of any of the building block measures described in this rule or any other measures permitted under the plan.

b. *Changes from the proposal.*

In the proposed rule, we determined that building block 1 measures could on average achieve a 6-percent heat rate improvement from coal-fired EGUs in the U.S. based on a 4-percent heat rate improvement from implementation of best practices and a 2-percent heat rate improvement from equipment upgrades. Based on comments received and refinements made to our methodology for determining potential heat rate improvement from the hourly gross heat rate dataset of 884 coal-fired EGUs, we have applied this methodology on a regional basis and reduced the overall expected percentage heat rate improvement for coal-fired EGUs to 4.3 percent in the Eastern Interconnection, 2.1 percent in the Western Interconnection, and 2.3 percent in the Texas Interconnection.[643] These values reflect improvements achievable through both best practices and equipment upgrades because, as described above, we also no longer include a separate estimation of the potential heat rate improvement achievable solely through equipment upgrades.

We received comments on our proposed statistical methodology for determining the CO_2 emission reductions opportunities achievable by coal-fired EGUs through heat rate improvements. We have closely reviewed those comments and, for the final rule, have made refinements to our methodology, as described above and explained in more detail in the GHG Mitigation Measures TSD supporting the final CPP.

In the final rule, the EPA extends the implementation deadline from 2020 to 2022. This additional time will be helpful to the states seeking to conduct more targeted analyses of the nature and extent of heat rate improvements that specific coal-fired EGUs can make, considering specific recent improvements or upgrades, planned retirements of older coal-fired EGUs, and other relevant considerations. The extended deadline will also provide additional time to accommodate

[641] To give an illustrative example, imagine a population of sources that emit Pollutant X. Half of the sources emit Pollutant X at 2500 lbs/hour, while the other half of the sources have scrubbers installed that reduce their emission rates to 1500 lbs/hour. Because the sources are evenly divided between those with and without scrubbers, the average emission rate for the population as a whole is 2000 lbs/hour. In this hypothetical, EPA decides to base requirements on the emission rate achievable through use of a scrubber, meaning that all sources will have to meet an emission rate of 1500 lbs/hour. Because the fleet as a whole has an average emission rate of 2000 lbs/hour, it would be accurate for EPA to say that the fleet as a whole can reduce its emission rate by 25 percent—from 2000 lbs/hour on average (only half the sources with scrubbers), to 1500 lbs/hour on average (all the sources with scrubbers). This description of what is possible *for the fleet as a whole*—a 25-percent reduction in emission rate—should not be misinterpreted as a statement that every *individual* source is capable of further reducing its emissions by 25 percent. The sources that have already installed scrubbers, and which are thus already operating at 1500 lbs/hour, would not be required to further improve their emission rate.

[642] Examples of the many types of best practices and equipment upgrades available to coal-fired EGUs include adopting sliding pressure operation to reduce turbine throttling losses; installing intelligent sootblowing system software; upgrading the combustion control/optimization system; installing heat rate optimization software; installing a production cost optimization program that benchmarks plant thermal performance using historical plant data; establishing centralized remote monitoring centers with thermal performance software for monitoring heat rates systemwide; repairing steam and water leaks; automating steam system drains; performing an on-site performance appraisal to identify potential areas for improved performance; developing heat rate improvement procedures and training O&M staff on their use; aligning the cycle to isolate or capture high-energy fluid leakage from the steam cycle; repairing utility boiler air in-leakage; performing utility boiler chemical cleaning; installing condenser tube cleaning system; retubing condenser; repairing/upgrading flue gas desulfurization systems; cleaning air preheater coils; adjusting/replacing worn air heater seals; replacing corroded air heater baskets; replacing feed pump turbine steam seals; overhauling high pressure feedwater pumps; installing fan and pump variable speed/frequency drives; upgrading turbine steam seals; upgrading all turbine internals; and installing coal drying systems. These and additional heat rate improvement measures are discussed further in the GHG Mitigation Measures TSD for the CPP Final Rule.

[643] Had the EPA maintained a nationwide approach to analyzing the potential reductions under building block 1, the result would have been 4.0 percent.

changes to heat rate monitoring methods at EGUs and for the installation of new pollution controls that comply with other rules, as discussed below in the summary of key comments.

2. Costs of Heat Rate Improvements

By definition, any heat rate improvement made by EGUs for the purpose of reducing CO_2 emissions will also reduce the amount of fuel that EGUs consume to produce the same electricity output. The cost attributable to CO_2 emission reductions, therefore, is the net cost of achieving heat rate improvements after any savings from reduced fuel expenses. As summarized below, we estimate that, on average, the savings in fuel cost associated with the percentage heat rate improvements we identified for each region would be sufficient to cover much of the associated costs. Accordingly, the net costs of heat rate improvements associated with reducing CO_2 emissions from affected EGUs are relatively low. We recognize that this cost analysis will represent the costs for some EGUs better than others because of differences in individual circumstances. We further recognize that reduced generation from coal-fired EGUs due to the implementation of other building block measures would tend to reduce the fuel savings associated with heat rate improvements, thereby raising the effective cost of achieving the CO_2 emission reductions from the heat rate improvements. Nevertheless, we still expect that a significant fraction of the investment required to capture the technical potential for CO_2 emission reductions from heat rate improvements would be offset by fuel savings, and that the net costs of implementing heat rate improvements as an approach to reducing CO_2 emissions from affected EGUs are reasonable. Even if we conservatively estimate that EGUs will largely rely on equipment upgrades rather than cheaper best practices to reduce heat rate, those reductions can generally be achieved at $100 or less per kW, or approximately $23 per ton of CO_2 removed, as described in detail in the GHG Mitigation Measures TSD supporting the final CPP.[644] Depending on the balance between equipment upgrades and best practices, improving heat rate would even result in a net savings for some EGUs.

[644] The $100/kW cost figure from the proposal is now particularly conservative because it included the cost of significant equipment upgrades that improve heat rate, whereas building block 1 is now largely quantified based on low- or no-cost best practices, with a smaller portion of the remainder comprised of equipment upgrades.

Based on the analyses of technical potential and cost summarized above and in Chapter 2 of the GHG Mitigation Measures TSD, we find that heat rate improvements of 4.3, 2.1 and 2.3 percent are reasonable and conservative estimates of what coal-fired EGUs in the Eastern, Western and Texas Interconnections, respectively, can achieve at a reasonable cost.

3. Response to Key Comments

Many commenters said that the EPA should have subcategorized by EGU design or operating characteristics for purposes of evaluating potential heat rate improvements under building block 1.

Several studies categorize EGUs broadly by capacity, thermodynamic cycle, fuel rank or other characteristics. We considered subcategorizing the EGUs by their design and fuel characteristics under building block 1. Although grouping by categories does not account for all of the factors that may affect heat rate, it can provide a useful way of understanding the operating profile of classes of coal-fired EGUs and the fleet as a whole. However, we have declined to subcategorize among affected coal-fired EGUs for both technical and practical reasons. First, as discussed above, our assessment of heat rate improvement potential uses a unit-specific data methodology that compares each EGU's performance against its own historical performance. By substantially basing our analysis on these unit-specific assessments, we inherently factor in the effect of numerous design conditions. We also conducted a regression analysis that evaluated the effect of numerous factors on heat rate, and found that subcategorizing would generally make little difference in our analysis. Additionally, subdividing the EGUs into subcategories would reduce the quantity of EGUs used to calculate each average, which would increase the influence of random and atypical variations in the data on the overall averages, and would thus decrease our confidence in the results. Furthermore, as a practical matter, states are free to apportion reductions in a way that reflects any subcategories of their choosing when determining the emission standards for individual affected EGUs. Additionally, commenters assert that because building block 1 is calculated on an average basis, some affected EGUs will have greater potential than others to reduce CO_2 emissions through heat rate improvements. If an affected EGU cannot meet its particular emission standard because it has below-average potential to reduce emissions through heat rate improvements, then in instances where the EGU's state plan allows emissions trading, the EGU can acquire credits or allowances from affected EGUs that have above-average potential. For a further discussion of our reasonable decision not to subcategorize among coal-fired EGUs for purposes of determining building block 1, see the GHG Mitigation Measures TSD supporting the final CPP.

Many commenters told the EPA that EGUs already have undertaken significant efforts to operate efficiently to provide reliable electric service at the lowest reasonable cost; that they believe they cannot significantly improve heat rate; that best practice maintenance activities are performed on a daily basis, including during maintenance outages that allow for the inspection, cleaning and repair of all equipment; that extensive capital investments have been made to install state-of-the art equipment and replace equipment that is beyond repair; and that their employees continuously monitor and control operating levels in the combustion process to maintain maximum combustion of fuel and to avoid wasting available heat energy. In summary, these commenters say they have expended considerable effort and resources to maintain peak boiler efficiency at all times and, therefore, the 6-percent heat rate improvement proposed for building block 1 is unreasonable to apply to EGUs across the board; the EPA should develop a rule that allows treatment of affected EGUs on a case-by-case basis.

We commend the efforts of those who strive to operate and maintain EGUs in the best possible manner to minimize heat loss and CO_2 emissions. This rule does allow for treatment of EGUs on a case-by-case basis. States may believe that individual considerations are appropriate in some cases and, accordingly, we have purposely allowed states to make decisions about how to implement specific CO_2 reductions. Our determinations of 4.3-, 2.1- and 2.3-percent heat rate improvement for EGUs in the Eastern, Western and Texas Interconnection, respectively, are conservatively based on the lowest value identified by any of our reasonable statistical analyses. If states choose to set limits on individual affected EGUs based in part on the availability of heat rate improvements, the states are free to assess heat rate improvements on a more targeted, case-by-case basis that takes into account an EGU's previous heat rate improvement efforts, or lack thereof. The fact that states (or EGUs complying with state requirements) can make case-by-case decisions about how to achieve goals does not contradict our conservative estimates—which are based on millions of hours of operating data reported to the EPA by EGUs—of how much EGUs are capable of improving their heat rate in each region overall. Opportunities to improve heat rate abound for affected EGUs as a whole, as evidenced by the fact that the approaches in our statistical methodology each included a comparison of an EGU's historical heat rate to its 2012 heat rate. Our estimates of the potential heat rate improvement are additionally conservative because they are based purely on comparisons among historical gross heat rate data, and thus do not reflect available, cost-effective opportunities to improve heat rate that affected EGUs never implemented during the study period. Finally, to the extent that an affected EGU was in 2012 fully implementing every possible best practice for improving heat rate, it may still be capable of improving heat rate through equipment upgrades.

Other commenters said that a 6-percent heat rate improvement overall is too high; that the heat rate improvement from upgrades are double-counted within the data used to determine heat rate improvements from best practices; and that the 2-percent heat rate improvement specifically for upgrades was inappropriately based on ''conceptual'' improvements from only one study.

We have reduced the 6-percent heat rate improvement from the proposed rule to three regionalized figures of 4.3 percent (Eastern), 2.1 percent (Western) and 2.3 percent (Texas), as discussed above and described in detail in the GHG Mitigation Measures TSD supporting the final CPP. We expect that, on average, affected coal-fired EGUs can at a minimum improve heat rate in these amounts by implementing best practices and equipment upgrades identified in the GHG Mitigation Measures TSD. These overall heat rate improvement figures do not include an estimated percentage heat rate improvement attributable specifically to upgrades. Although we are no longer including in our calculation of building block 1 a separate 2-percent heat rate improvement attributable solely to equipment upgrades, this decision is not because we believe that our initial 2-percent assessment of equipment upgrades was incorrect. To the contrary, the information presented in the S&L study was similar to that in other industry reports and studies—many of which were referenced in the proposal TSD—describing potential heat rate improvements at EGUs from all types of equipment upgrades. However, we recognized that the possibility existed that some limited portion of that 2 percent was also reflected in our statistical analyses of historical gross heat rate data. In order to ensure that our methodology did not double-count an indeterminate amount of heat rate improvement available through equipment upgrades, we conservatively set aside the entire additional 2 percent attributable solely to equipment upgrades. Accordingly, we determined the amount of potential heat rate improvement in the BSER solely from the heat rate analyses described above, which account for improvements through best practices and equipment upgrades that were at some point achieved by an EGU, but not for the full range of best practices and equipment upgrades that are actually available.

Commenters also said that the EPA did not look at important factors that affect heat rate such as coal type, boiler type, cooling water temperature, age, nameplate capacity or the use of post-combustion pollution controls.

Our statistical methodology compared each unit to its own historical performance and, therefore, largely accounts for the effects that a unit's design or fuel characteristics would have on heat rate. As discussed above, our methodology used hourly data from 884 units over an 11-year period (2002–2012) and compared the variability in the heat rate of each individual unit to that unit's own performance. By assessing potential heat rate improvement by first looking at unit-specific data, our methodology inherently factors in the possible effects of design and fuel characteristics (*e.g.,* coal type, boiler type, nameplate capacity, age, cooling water system, air pollution controls) on heat rate and heat rate variability.

Although cooling water temperature likely plays an important role in a coal-fired EGU's heat rate, as stated by commenters, there are no consistent quality-assured hourly cooling water temperature data available to the EPA. However, in an effort to determine the potential effect of cooling water temperature on heat rate, we looked at a sample of 45 coal-fired EGUs at 19 facilities for which we had hourly surface water temperature data (used as a surrogate for cooling water) from monitors located nearby and upstream of cooling water intake points. Our analysis found that surface water temperature did explain some of the variation in heat rate, but that surface water temperature is strongly correlated with ambient air temperature—a variable we did control for in our methodology. Because of the strong correlation between ambient air temperature and surface water temperature, the availability of a comprehensive dataset of nationwide hourly ambient air temperature, and the similar explanatory power of surface water temperature and ambient air temperature, it is unlikely that separately addressing cooling water temperature would significantly change the results. Rather, we are confident that our use of hourly ambient air temperature in our analyses adequately addressed any significant impact of cooling water temperature. See the GHG Mitigation Measures TSD supporting the final CPP for further details about this analysis. As described further in that TSD, the other potentially relevant variables for which we did not directly control are unlikely to significantly affect the average heat rate.

Commenters said that the heat rate improvement attributable to upgrades will degrade over time or require repeated and costly further upgrades.

We are aware that some heat rate improvement measures can degrade over time. Like most power plant components, some heat rate improvement technologies require maintenance in order to sustain their efficacy over time. Therefore, to avoid degradation, personnel at EGUs will need to diligently apply ''best practices'' on a regular basis, a practice that numerous commenters say is standard operating procedure. The S&L study includes estimates of associated operations and maintenance (O&M) costs for each heat rate improvement method that is discussed. As we explained in the proposal, the related O&M costs of diligently applying best practices are relatively small compared to the associated capital costs and would, therefore, have little effect on the economics of heat rate improvements.

Commenters stated that heat rate improvement should be set on a basis that is narrower than nationwide—for example, state-by-state or unit-by-unit.

The EPA did not propose and is not finalizing a rule that sets heat rate improvement goals for individual states or for individual coal-fired EGUs. Instead, in the approved state plans developed under this rule, each state will set the emission standards for its various coal-fired EGUs. In doing so, the state may take into account its own view of the amount of heat rate improvement needed (if any) at specific EGUs, and may look to the EPA's analysis of heat rate improvement potential in the applicable region as a guide, while keeping in mind the CO_2 emission performance rate. This broad-based approach is consistent with the traditional rules evaluating the potential for emission reductions on a source-category basis, and is consistent with the broader goal-setting purpose of this rule. Furthermore, the final rule establishes a uniform national performance rate based on the least stringent regional performance rate calculated with the building blocks. Accordingly, affected EGUs in regions not setting the national level have emission reduction opportunities beyond those reflected in the applicable performance rate.

The heat rate improvement measures comprising building block 1 would ordinarily be evaluated on a nationwide basis. However, in this instance there are two good reasons to calculate building block 1 on a regionalized basis. First, a regionalized approach is consistent with the EPA's approach to determining the other building blocks. For building block 1, this means that the heat rate improvement should reflect only as much potential for emission reduction from building block 1 as our analyses indicate can be achieved on average by the affected coal-fired EGUs in that region. This ensures that the BSER for each region is representative of the characteristics and opportunities available within that region, rather than a less logical combination of opportunities in the region and opportunities nationwide. Second, a regionalized approach provides a more representative average of the potential heat rate improvement that EGUs in a given region are capable of achieving. The populations of affected coal-fired EGUs in each region differ in some respects, as discussed in the GHG Mitigation Measures TSD, and the more nuanced regionalized approach thus indirectly accounts for some of those systemic differences. For these and other reasons described in Section V.A. of the preamble with respect to the BSER as a whole, we have reasonably based building block 1 on a regionalized approach. Applying this regionalized approach to building block 1 strikes an appropriate balance between the proposed nationwide analysis and commenters' suggested state-specific analysis, which does not fully reflect the interconnected nature of the system within which affected coal-fired EGUs operate.

The practical consequence of calculating building block 1 on a regionalized versus nationwide basis is minimal. This is because the CO_2 emission performance rates are based on the overall performance rate determined to be reasonable for EGUs in the Eastern Interconnection. Our methodology identifies a 4.3 percent potential improvement in the Eastern Interconnection, compared to a 4.0 percent figure across all three interconnections.

We further note, along with some commenters, that site-specific engineering studies or unit-by-unit analyses of heat rate improvement potential for coal-fired EGUs are not available to the EPA; only a small number of site-specific case studies are available in the public literature. We considered that for the EPA to develop a comprehensive, unit-by-unit heat rate improvement study of nearly 900 coal-fired EGUs from scratch, it would likely cost the Agency $50,000 to $100,000 to study each EGU (almost $50 to $100 million total) and require three to four years to complete. Such a granular analysis would not serve the broader goal-setting purpose of this rulemaking. We agree with commenters who have pointed out that a heat rate improvement-estimating effort of that magnitude and duration would be unnecessarily lengthy and expensive. Nor would such a granular analysis be a necessary predicate for states to develop emission standards, or for EGUs to comply with those emission standards. Rather, our methodology relies on individualized, unit-by-unit hourly performance data from 884 EGUs provides conservative and reasonable regional estimates of heat rate improvement potential. Indeed, given the conservative nature of our methodology, a unit-specific approach that evaluates the full range of best practices and equipment upgrades available at individual EGUs—including upgrades not accounted for here—would be more likely to result in higher overall heat rate improvement figures than we are finalizing for building block 1. Furthermore, site-specific information forms the foundation of the EPA's estimated heat rate improvement potential, and similar data likely would be used in any site-specific heat rate improvement engineering study. Finally, EGU-specific detailed design and operation information is not consistently available for all the factors that influence heat rate. The EPA has used the comprehensive data that are available to reasonably and conservatively estimate potential heat rate improvement in each region.

Commenters also said that shifting electricity generation from coal-fired EGUs to other EGUs because of measures implemented under other building blocks will lower the capacity factors of coal-fired EGUs, and thus increase, not decrease, their heat rates.

We expect that most states will develop plans that optimize the operation of existing coal-fired EGUs while utilizing the other building blocks and other measures to reduce emissions from carbon-intensive generation. From our IPM projections, the average annual capacity factor of existing coal-fired EGUs that are expected to remain in operation in 2030 will actually increase compared to 2012. This projection—which is further described in the GHG Mitigation Measures TSD—incorporates expected retirements of inefficient units and generation shifts away from using coal-fired EGUs as peaking units.

Commenters also noted that the EPA used net heat rate in state goals, but used gross heat rate in its heat rate improvement analysis—potentially ignoring the detrimental effect that parasitic load from air pollution control devices (APCD) and other equipment can have on net heat rate.

The EPA's variability analysis necessarily and reasonably used gross output data for each of the 884 EGUs in the EPA's database because they are the only publicly available, unit-specific, hourly performance data. By definition, improvement in gross heat rate would be reflected in the net heat rate. Gross heat rate is the total heat output from the EGU, in units of Btu/gross kWh, and includes the power used by auxiliary equipment required to operate the EGU itself. By contrast, net heat rate is the remaining Btu/kWh after subtracting the power used by the EGU's own auxiliary equipment from the gross heat rate value, *i.e.,* what the EGU is able to provide to the grid. Improvements in net heat rate alone (*e.g.,* reducing parasitic load of on-site equipment) may be possible on many units. Therefore, our use of gross heat rate to estimate potential heat rate improvement was conservative because of the additional opportunities to achieve the uniform performance rate through improvements in net heat rate alone.

Commenters also raised concerns that the EPA was not taking into account net heat rate increases due to additional add-on pollution controls that may, for some units, be required by other rules.[645]

The results of our statistical analyses are based on gross heat rates and would not change with installation of emission controls for CSAPR, MATS, or other rules because these controls will add parasitic load requirements and thereby have an impact on the net heat rates only. Furthermore, we conservatively consider region-wide net heat rate

[645] See above for an explanation of gross versus net heat rate.

improvement potential to be the same as that indicated for the region-wide gross heat rate, when in fact it is not. In order to check our assumptions concerning gross versus net heat rate, we used the IPM Power Sector Modeling Platform (version 5.14) and National Electric Energy Data System (NEEDS) (version 5.14) to analyze the anticipated incremental heat input required to operate additional add-on controls to comply with various EPA rules, including CSAPR, MATS, effluent guidelines for EGUs, and coal combustion residuals. From this analysis, we project that between 2012 and 2025, existing coal-fired EGUs are expected to install approximately 18.6 GW of wet flue gas desulphurization (FGD), 16.6 GW of dry FGD, 24.9 GW of selective catalytic reduction (SCR), and 3.9 GW of selective noncatalytic reduction (SNCR). The resulting impact from new pollution controls on existing coal-fired EGUs' heat rate is expected to be very small, at conservatively less than 31 Btu/kWh, or less than 0.3 percent in 2025.[646] After 2025, this estimate is particularly conservative because the EPA's cost performance models overestimate the parasitic load from individual add-on controls for future years. Furthermore, at some EGUs these newer pollution control devices will replace existing pollution control devices. Accordingly, for these EGUs, the minimal increase in net heat rate due to power required to operate new controls will be at least partially offset by the decrease in net heat rate caused by removal of the control devices currently in place. For more information about this analysis, see the GHG Mitigation Measures TSD supporting the final CPP.

Commenters contended that the 11 years of data used to evaluate potential heat rate improvement is too broad, and that the population of domestic coal-fired EGUs has changed significantly over this time period.

The 11-year span for the hourly gross heat rate data is appropriate because it represents a wide variety of economic conditions, market conditions and fleet composition, while also capturing the relatively recent historical performance of affected coal-fired EGUs. We also noted in the proposal TSD that the population of coal-fired EGUs used in the analytical approaches to determine potential heat rate improvement is made up of coal-fired EGUs that operated in 2012. The gross heat rate data of any coal-fired EGUs that retired prior to 2012 were not included in the dataset.

Commenters stated that many of the changes in heat rate reflected in the 11-year hourly gross heat rate dataset are attributable to changes in monitoring methodology, and thus do not represent heat rate improvements attributable to best practices or equipment upgrades. In addition, commenters are concerned that changes to the monitoring methodology in the future could artificially alter the measured heat rate.

Different stack gas flow monitoring methods can yield more or less accurate measurements of heat input and CO_2 emissions. These differences depend on the characteristics of the stack gas flow where the monitoring and reference method measurements are taken, and which options under the Part 75 emission measurement rules are chosen in the application of the various flow rate reference methods. In general, more accurate stack gas flow monitoring methodologies yield lower values that, when used to calculate emissions or heat input, may lower the heat rate values reported to the EPA.

Some EGUs adopted monitoring methodologies that have the potential to affect the exactness of the data we used for assessing heat rate improvements. However, as discussed in detail in the GHG Mitigation Measures TSD supporting the final CPP, our review of the data shows that a relatively small amount of the data are affected by these changes; we are confident that the values adopted for building block 1 are conservative and reasonable estimates of the potential for heat rate improvement in each region. Some changes in monitoring methodology would have the result of tending to cause us to underestimate the potential for heat rate improvement. Furthermore, because our methodology analyzes percentage heat rate improvement based on 2012 gross heat rate data, our results are unaffected by EGUs that used more accurate monitoring methodologies in 2012 or used the same monitoring methodologies consistently throughout the 11-year study period. For these and other reasons discussed in detail in the GHG Mitigation Measures TSD, we remain confident in our results despite the marginal differences attributable to monitoring methodologies in some of the heat rate data for a subset of EGUs.[647]

In terms of concerns with future methodological changes, the overwhelming majority of the 884 EGUs in the dataset we used to assess heat rate improvement have already changed their stack gas flow monitoring methodology in 2012 or earlier. Furthermore, extension of the compliance date to 2022 for this rule, as discussed above, more than adequately allows enough time for EGUs to determine how to actually improve their heat rates and lower CO_2 emissions while accommodating future changes to monitoring methodologies. For a more detailed explanation, see the GHG Mitigation Measures TSD supporting the final CPP.

Commenters said that there is no proof that lowering the heat rate will reduce variability or that reduced variability will reduce heat rate, *i.e.,* correlation does not prove causation.

As an initial matter, it is important to note that for the final rule the EPA used three types of statistical analyses to evaluate and estimate potential heat rate improvements of coal-fired EGUs, and only one of these analyses involved any consideration of heat rate variability. All three types of statistical analyses are described in the GHG Mitigation Measures TSD supporting the final CPP.

These commenters are correct that, in the abstract, reducing heat rate variability only means that heat rate will be more consistent—not necessarily lower or higher. However, our analysis is not an abstract evaluation of the potential to reduce variability, as commenters suggest, but rather is an evaluation of the potential heat rate *improvement* achievable through reducing variability—*i.e.,* reducing variability to achieve a more consistently low heat rate. See the more detailed discussion of the statistical procedures used for the final rule, above. In particular, the application of a ''consistency factor'' in the analyses performed for both the proposed and final rule demonstrates the potential results if each individual EGU operated slightly more consistently with the lower heat rates that the EGU had itself previously achieved under similar conditions.

The consequence of a reduced heat rate is, of course, a lower rate of CO_2 emissions, which is the purpose of the BSER for building block 1. This way of thinking about reduced variability is consistent with the utility power sector's own efforts to reduce variability, which are aimed at securing

[646] When considered on a regional basis, we expect these controls to impact heat rate by approximately 0.3 percent in both the Eastern and Western Interconnections, and by less than 0.1 percent in the Texas Interconnection.

[647] Furthermore, on a fundamental level, our methodology accounts for a certain amount of any residual inexactness because we have conservatively adopted the lowest value identified by any of our reasonable approaches—all three of which are themselves conservative because they do not account for the full extent of heat rate improvements achievable through equipment upgrades.

the economic benefits of a more consistently *lower* overall heat rate.

Some commenters expressed concern that heat rate improvements could trigger applicability of new source review (NSR) provisions. The relationship of this final rule to other regulatory provisions, including NSR, is discussed in section X of the preamble.

D. Building Block 2—Generation Shifts Among Affected EGUs

The second element of the foundation for the EPA's BSER determination for reducing CO_2 emissions at affected fossil fuel-fired EGUs entails an analysis of the extent to which fossil steam EGUs can shift generation to existing NGCC EGUs. In this section, we define building block 2 as the gradual shifting of generation from existing fossil steam to existing NGCC within each region up to a maximum NGCC utilization of 75 percent on a net summer basis. In each year of the interim period, this 75 percent net summer maximum potential is subject to a regional limit informed by historical growth rates.

This section summarizes the EPA's analysis supporting that definition. We begin by discussing the sector's ability to reduce CO_2 emissions by shifting generation, including selected background information, data on trends toward greater NGCC generation, and various mechanisms for executing or facilitating generation shifts. Next, we describe the amount and timing of generation shift we have determined to be achievable through the building block. We then discuss various elements supporting our quantification of achievable generation shift, including the technical feasibility of NGCC units to increase generation; historical shifts to NGCC generation; considerations related to reliability, natural gas transmission infrastructure, natural gas production, and electricity transmission infrastructure; and regulatory flexibility. A discussion of costs follows. Finally, we respond to certain comments not addressed in the preceding discussions.

1. Demonstration of Ability To Reduce CO_2 Emissions Through Shifting Generation

a. *Background of utility power sector.* The ability to shift generation from higher- to lower-emitting sources is compatible with the way EGUs are generally dispatched.[648] The standard approach to dispatching generation is through Security Constrained Economic Dispatch (SCED), a well-established practice in the electric power industry.[649] As the name indicates, SCED has two defining components: Economic operation of generating facilities and assurance that the electric system remains reliable and secure.[650] Economic dispatch generally refers to shorter-term planning and operations from a day ahead through real time. During this period, generating units are committed—a process known as ''unit commitment,'' in which units are committed to be ready to provide generation to the system when they will be needed—and then dispatched in real time to meet the electricity demand of the system. Overall changes in the level of generation from different facilities are also planned over time periods longer than this 2-day dispatch period. Over a calendar year, for example, units are planned and scheduled seasonally or monthly to ensure that sufficient capacity and energy will be available to meet expected loads in an area. Over a period of a week, units are committed to be prepared to start up or shut down to meet forecast loads, and dispatch is coordinated within this planning and unit commitment framework. This process enables system operators to respond quickly to short-term changes in demand, and also to shift generation among different generation types to match longer-term requirements and goals.

EGUs using technologies with relatively low variable costs, such as nuclear units, are for economic reasons generally operated at their maximum output whenever they are available. Renewable EGUs such as wind and solar units also have low variable costs, but the magnitude and timing of their output generally depend on wind and sun conditions rather than the operators' discretion. In contrast, fossil fuel-fired EGUs have higher variable costs and are also relatively flexible to operate. Fossil fuel-fired EGUs are therefore generally the units that operators use to respond to intra-day and intra-week changes in demand. Because of these typical characteristics of the various EGU types, the primary opportunities for switching generation among existing units available to EGU owners and grid operators generally consist of opportunities to shift generation among various fossil fuel-fired units, in particular between coal-fired EGUs (as well as oil- and gas-fired steam EGUs) and NGCC units. In the short term—that is, over time intervals shorter than the time required to build a new electric generation unit—fossil fuel-fired units consequently tend to compete more with one another than with nuclear and renewable EGUs. The amount of generation shifting from coal-fired EGUs to NGCC units that takes place as a result of this competition is highly relevant to overall power sector GHG emissions, because a typical NGCC unit produces less than half as much CO_2 per MWh of electricity generated as a typical coal-fired EGU.

b. *Trends in generation shifts from coal-fired to natural gas-fired sources.*

Since at least 2000, fossil fuel-fired generation has been shifting from coal- and oil-fired EGUs to NGCC units, both as a result of construction of additional NGCC units, and also as a result of dispatch of pre-existing NGCC units at higher capacity factors. As a result, generation from NGCC EGUs in 2012 reached over four times the level of NGCC generation in 2000, while generation from coal and oil/gas steam EGUs decreased by around one third.[651] As we demonstrate in the GHG Mitigation Measures TSD, NGCC units are capable of operating at higher annual capacity factors than they have historically, so there remains considerable opportunity for increased use of existing NGCC units to replace generation currently supplied by higher-emitting coal and oil/gas steam units. The electric utility industry is thus well-positioned to address the requirements of this building block by increasing use of existing NGCC units and correspondingly decreasing use of steam units. The electric industry has been shifting generation to NGCC units in recent years and is expected to continue to retire coal capacity and add new NGCC capacity. In the reference case without implementation of CO_2 emission limitations, EIA forecasts 40 GW of coal retirements and 53 GW of NGCC capacity additions from 2014 to 2030.[652] An EPA review of state Integrated Resource Plans (IRPs) shows a pattern of shifting away from coal steam capacity to NGCC capacity and, in some cases, conversion of coal steam capacity to natural gas steam capacity. For example, Ameren plans to add 600 MW of NGCC capacity and convert two coal units to natural gas steam units, and Duke plans to add 680 MW of

[648] See preamble section II.C.1, History of the Power Sector, for background to this discussion.

[649] ''Economic Dispatch: Concepts, Practices and Issues'', FERC Staff Presentation to the Joint Board for the Study of Economic Dispatch'', Palm Springs, California, November 13, 2005. A copy of this presentation is available in the docket for this rule.

[650] ''Security Constrained Economic Dispatch: Definitions, Practices, Issues and Recommendations: A Report to Congress'', Federal Energy Regulatory Commission, July 31, 2006.

[651] Ventyx Electric Power Database.

[652] Energy Information Administration, Annual Energy Outlook 2015 reference case, ref2015.d021915a.

NGCC capacity and convert one coal unit to a natural gas steam unit.[653]

c. *Mechanisms for dispatch shifts from coal-fired to natural gas-fired generation.*

There are a variety of patterns of ownership and operational control of EGUs; these ownership and operational structures influence how EGUs will respond to this building block. However, all owners and operators have the ability to comply by using this building block. In terms of ownership, investor-owned utilities (IOUs) serve about 75 percent of the US population, while consumer-owned utilities serve the remaining 25 percent.[654] In states that have maintained traditional regulation, IOUs are generally vertically integrated (owning generating capacity as well as transmission and distribution infrastructure), and the wholesale sales of these EGUs are regulated by the state; in states that have deregulated their retail service, ownership of the EGU is separated from ownership of transmission, and wholesale sales of generation are regulated by FERC. Consumer-owned utilities comprise municipal utilities, public utility districts of various types owned by government agencies, nonprofit cooperative entities (co-ops), and a number of other entities such as Native American Tribes.

Operational control of the dispatch of power over the electricity grid is superimposed on this pattern of ownership. Prior to electricity restructuring, this dispatch was typically operated by major vertically-integrated utilities or by public power entities. Over the last 15 years, large portions of the power grid are now independently operated by ISOs or RTOs. These entities are regulated by FERC and dispatch power from multiple owners to meet the loads on the bulk power grid.

The combination of multiple ownership and types of operational control adds to the complexity of electricity dispatch, but all affected EGUs, regardless of ownership and type of control, can use this building block to comply with the final rule. The principal difference among the differing entities lies in the types of methods that are available for the affected EGU owner to bring about the shift in generation that will make use of this building block for compliance. There are several alternatives to accomplish this result: The owner of the higher-emitting affected EGU may also own, or have affiliates that own, lower emitting generation and thus reduce its own generation and use its control over these other EGUs to increase their generation; an EGU may be able to reduce its generation and buy replacement power from the market that is lower emitting; or the EGU may be able to reduce its generation and procure generation from a separately-owned lower-emitting EGU. These alternatives will be available in states with either rate or mass-based state plans without any change in their general form. Under a rate-based state plan, an EGU owner may also be able to purchase ERCs and average the ERCs into its emission rate for purposes of demonstrating compliance with its standard of performance. Under standards of performance that incorporate emissions trading, an EGU owner may be able to purchase rate-based emission credits or mass-based emission allowances not needed by other EGUs and use those credits or allowances to help achieve its standard of performance.

The potential to shift generation identified for this building block is entirely consistent with the existing economic dispatch protocols described above. State environmental policies can shift generation in two ways. The first is operational restrictions, such as permit limits on the number of hours that an EGU can operate in order to limit emissions. The second is changes in the relative costs of generation among different types of EGUs related to pollution reduction measures. For example, a regulation that necessitates the use of a control technology that requires the application of a reagent in a certain kind of EGU will increase the variable cost of operating that plant, which in turn may reduce the amount of generation it is called upon to deliver to the grid through security-constrained economic dispatch procedures.

In an organized market, where the system operator dispatches units partly based upon costs, an electric power plant that experiences an increase in its variable costs will tend to operate less than it otherwise would have. For example, market-based pollution control programs require units to hold tradable allowances to authorize their emissions of a regulated pollutant. Such an allowance-holding requirement puts a price on the act of emitting the regulated pollutant, which increases the operating costs of units that emit that pollutant, and thus such units will be dispatched less than they otherwise would without such an allowance-holding requirement. The RGGI is an example of a state program that has this effect. In the present rule, although shifts in the mix of generation to address the costs of pollution control can lead to higher electricity generating costs overall, the EPA analysis shows these costs to be modest and well below their associated benefits.[655]

Many of the NGCC units are owned by the same companies or affiliates that also own steam units. In these cases, changes in EGU generation can be planned by the company or affiliate without the need to engage in separate market transactions with outside parties. Where the affected EGU owner is also the dispatch entity, as in most traditional market structures, the EGU owner will generally have operational control over the unit. Environmental conditions, such as compliance costs or limits on generation, can be factored in with fuel costs for purposes of determining when the unit is committed to be available, how the unit can be most efficiently cycled, and at what level the unit is dispatched.

An analysis of generation data from steam and NGCC units in 2012 shows that 77 percent of the steam generation occurred from an EGU that owned, or that had an affiliate that owned, NGCC generation. Eighty percent of the generation shift potential identified in this building block (increasing NGCC generation up to a 75 percent capacity factor on a net basis to replace steam generation) could occur among these entities that own (either directly or through affiliates) both steam and NGCC generation.[656] These data show that most EGU generation relevant for this building block is produced by entities that own both steam and NGCC generation.

Another alternative available to an affected EGU owner that does not also own NGCC generation is for the higher-emitting affected EGU to reduce its generation and purchase replacement power from the market. In organized markets such as RTOs, it is available through standard practice, because the owner impacts how its EGUs are dispatched based upon how it bids into the RTO market. In this case, the owner can exercise control over the levels of generation across units by when it offers generation to the market operator (the RTO or ISO), and the prices it bids for this generation. As in traditional economic dispatch by a utility, environmental conditions, compliance

[653] For further examples, see the memo entitled ''Review of Electric Utility Integrated Resource Plans'' (May 7, 2015) available in the docket.

[654] Regulatory Assistance Project, Electricity Regulation in the US: A Guide, Page 9, March 2011. Available at *http://www.raponline.org/docs/RAP_Lazar_ElectricityRegulationInTheUS_Guide_2011_03.pdf*.

[655] See the Regulatory Impact Analysis.

[656] SNL Energy. Data used with permission. Accessed May 2015.

costs, or limits on generation can be incorporated by the owner into the determination of the cost-effective generation pattern of its EGUs.

In regions with organized electricity markets (including, but not limited to, RTOs or ISOs), the various types of EGU owners of higher-emitting sources can reduce their generation, and any resulting deficit in generation on the system can be supplied from other EGUs in the region; for example, a coal-fired unit can reduce generation that is then replaced through the operation of the market by generation from an NGCC unit, subject to dispatch by a regional operator to ensure the reliable delivery of the generation to loads within the region. To comply with this rule, higher-emitting steam units will need greater emission reductions relative to lower-emitting NGCC units which will, in turn, tend to raise steam unit costs compared to NGCC units. As a result, the bids that a steam unit provides a market operator will rise relative to NGCC units. This process of reducing generation from a higher-emitting unit will lead to substitution of lower-emitting generation.

EGU owners that do not participate in an organized electricity market may nevertheless purchase power from the wholesale power market. Purchases in the wholesale power market can be spot purchases, which are typically general purchases of system power supplied by the EGUs across a region, or contract purchases, which may have more provider-specific characteristics (such as specifying the type of unit that is providing the power). Purchases between EGUs through the wholesale power market will have similar emission-lowering properties as operation of the organized market discussed above, because dispatch in balancing areas outside RTOs and ISOs also follows a similar economic dispatch protocol that is informed by each unit's production costs and environmental limitations.

Under this alternative, the steam generators may, in effect, realize emission reductions from building block 2 simply by reducing their generation. Steam generators do not need to purchase replacement electricity as a prerequisite for realizing emission reductions from reducing their own generation because other generators already have an incentive to provide as much electricity as load-serving entities are willing to buy in order to satisfy electricity demand.[657] As noted above, higher-emitting generation sources will have to incorporate correspondingly higher costs of pollution reduction into their supply bids compared to lower-emitting generation sources, and as a result, load-serving entities will seek to buy a greater share of electricity from the lower-emitting sources because their supply bids will be more economically attractive. Once the steam generators reduce their generation (and associated emissions), the other entities in the electricity system arrange for the replacement electricity. The outcome of this power market process will reduce both the mass and the rate of emissions across sources.

An owner of a source can also reduce the generation of an EGU by substituting generation from a lower-emitting NGCC directly. For an EGU owner without existing NGCC generation, this substitution can take the form of a bilateral contract purchase. In RTOs and ISOs, this alternative often takes the form of a contract for differences, where the replacement source could be an NGCC and the contract specifies a delivery location and the price of the power. In bilateral markets, the contract vehicle could be a Power Purchase Agreement from a replacement source. It is also possible that the owner of a steam unit could directly invest in an existing EGU by purchasing the asset or taking a partial ownership position, thus acquiring the generation from the unit through that means. The acquired generation and its associated emissions could be used for compliance by the higher-emitting EGU, in accordance with the plan under which it is operating. The amount of generation that could be shifted using the approaches described in this paragraph will depend on the type and terms of the commercial arrangements, as well as the potential need for regulated entities to obtain approvals for contracts or for changes in asset positions. The wide range of approaches permitted by this rule provides flexibility, both within a year and across multiple years, for EGUs to fashion these arrangements to fit their circumstances.

Where permitted under its state plan, an EGU would also be able to meet its reduction obligations using ERCs or allowances. The particular nature of this alternative will depend on how a state elects to develop its plan. If a state chooses a mass-based approach, the EGU would simply need to hold allowances to cover its emissions. To realize an emission reduction from building block 2 under this approach, a steam generator would only need either to reduce its emissions by reducing its generation, which would lead to that generator needing fewer allowances to cover its emissions under the program, or to purchase surplus allowances not needed by another EGU that had reduced its emissions. In a rate-based state, the state may choose to provide for compliance through the acquisition of tradable ERCs. To realize an emission reduction from building block 2 under this approach, a steam generator would be able to adjust its effective emission rate by purchasing ERCs that are produced by other sources whose emission rates are lower than the applicable rate standard. In this fashion, a steam generator does not need to purchase lower-emitting replacement power per se in order to demonstrate an emission reduction from this building block; instead, the steam generator may purchase any ERCs that were produced from lower-emitting sources (see section VIII for more detail on how state plans can use an ERC approach to facilitate a rate-based compliance demonstration of this type of emission reduction).[658]

The approaches shown here collectively demonstrate that all steam generators—regardless of size, location, form of ownership, or type of market in which they operate—can implement building block 2 through some or all of the mechanisms described.

2. Amount and Timing of Generation Shift

The EPA has determined that for purposes of quantifying the CO_2 emission reductions achievable through building block 2, a reasonable amount of generation shift is the amount of generation shift that would result from existing NGCC units, on average, increasing their annual utilization rates to 75 percent of net summer capacity. However, the building block does not reflect achievement of this average capacity factor at the start of the interim period, but instead reflects a glide path of increases in NGCC utilization over

[657] Some owners or operators of steam generators may have electricity supply obligations to which they may be applying power from those steam generators. However, such parties may fulfil those supply obligations using the wholesale power market in the exact same way described here that enables any other generator with economically attractive electricity to offer such supply. In other words, the ability of a steam generator to reduce its generation is not contingent on an associated purchase to replace that power, notwithstanding the possibility that the owner or operator of that steam unit may choose to make such a purchase to meet an electricity supply obligation.

[658] Stakeholders have recognized that ERCs and allowances are an effective tool for EGUs to implement the building blocks and achieve their standards of performance required under this rule. *See* ''Clean Power Plan Implementation: Single-State Compliance Approaches with Interstate Elements,'' Georgetown Climate Center (May 2015), *http://www.georgetownclimate.org/sites/www.georgetownclimate.org/files/GCC_ComplianceApproacheswithInterstateElements_May2015.pdf.*

the interim period. Below, we discuss the glide path, and in the following section we discuss the basis for finding the 75 percent utilization rate, achieved over the period of time consistent with the glide path, to be reasonable.

The EPA received significant public comments expressing concern regarding the proposal's incorporation of the full building block 2 shift in generation by the first year of the interim period. These commenters perceived this approach as requiring states to achieve such a significant portion of the required CO_2 emission reductions early in the interim period that states would lack flexibility in when and how they may achieve the required emission reductions. Other commenters expressed concern that the full extent of building block 2 would be difficult for some states to achieve by the first year of the interim period as a result of technical, engineering, and infrastructure limitations or other considerations; that such timing may crowd out other cost-effective options for emission reductions; and that such timing might have negative implications for reliability.

In the proposal, the EPA determined that emission reductions are feasible and achievable at fossil fuel-fired steam EGUs by shifting from more carbon-intensive EGUs to less carbon-intensive EGUs, as part of the BSER. More specifically, the EPA proposed that generation shifts from fossil fuel-fired steam units (which are primarily coal-fired) to NGCC units, up to a utilization of 70 percent on a nameplate capacity basis, could be achieved by 2020. In contrast, the EPA proposed that reductions in CO_2 emissions from fossil fuel-fired units associated with other measures, such as increased utilization of RE generating capacity and increased demand-side EE, would be achievable on a phased-in basis between 2020 and 2029, reflecting the time needed for deployment.[659] In light of the concerns noted above, in the October 2014 NODA, the EPA solicited comment on potential rationales for phasing in the potential to shift generation under building block 2.[660]

As already noted, in the final rule the EPA has revised the interim period to start in 2022, which itself is a meaningful response regarding the concerns expressed by commenters about the timing of building block 2's generation shift potential. In addition, the EPA has evaluated the feasibility over time of building block 2 within the framework of BSER, and is finalizing a change to building block 2 that gradually phases in the shift from existing fossil steam to existing NGCC over the interim period. This phase-in allows for additional time to complete potential infrastructure improvements (*e.g.,* natural gas pipeline expansion or transmission improvements) that might be needed to support more use of existing natural gas-fired generation, and provides states with the increased ability to coordinate actions taken under building block 2 with actions taken under building block 3 (deployment of new renewable capacity).

The phase-in schedule applies a limit to the maximum building block 2 potential in each year of the interim period based on two parameters. The first parameter defines an amount of generation shift to existing NGCC capacity that is feasible by 2022, and the second parameter defines how quickly that amount could grow until the full amount of NGCC generation could be achieved as part of the BSER. Both of these parameters are determined by examining the extent to which gas-fired generation has increased over historical time periods. The first parameter is based on the single largest annual increase in power sector gas-fired generation since 1990, which occurred between 2011 and 2012 and is equal to 22 percent.[661] We believe that this amount is a conservative estimate of the ability of the sector to increase utilization of NGCC capacity by 2022, given that this increase has already occurred in a single year. The second parameter is based on the average annual growth in gas-fired generation in the power sector between 1990 and 2012, which is approximately 5 percent per year.

In the performance rate calculation methodology, these two parameters constrain the annual rate at which building block 2 shifts generation from fossil steam units to NGCC units. The interim performance rate is an average of annual rates calculated over the 2022–2029 period. The two parameters above limit the extent to which NGCC generation is able to increase and replace fossil steam generation in each year of the interim period. In the first year, NGCC generation is limited to a maximum of a 22 percent increase from 2012 levels in each region. In each subsequent year, regional NGCC generation is limited to a maximum of a 5 percent increase from the previous year. This phase-in continues in the performance rate-setting methodology until the full building block 2 level of shifting from fossil steam generation to NGCC generation is reached. Under this approach, building block 2 is completely phased into the source category calculation of all regions by the end of the interim period.

TABLE 7—BSER MAXIMUM NGCC GENERATION BY REGION AND YEAR (TWh)

Region	NGCC generation (TWh)										
	Maximum potential at 75%	2012 (adjusted)	BSER maximum								
			2022	2023	2024	2025	2026	2027	2028	2029	2030
Limit			22%	5%	5%	5%	5%	5%	5%	5%	5%
Eastern Interconnection	988	735	896	941	988	988	988	988	988	988	988
Western Interconnection	306	198	242	254	267	280	294	306	306	306	306
Texas Interconnection	204	137	167	176	185	194	203	204	204	204	204

This phase-in, in addition to the flexible nature of the goals, ensures that the overall framework of this final rule includes sufficient flexibility, particularly with respect to timing of and strategies for reducing emissions from the affected units, so that states can develop cost-effective strategies and allow for infrastructure improvements to occur should they prove necessary in some locations.

[659] 79 FR 34866.

[660] 79 FR 64543.

[661] US EIA Monthly Energy Review, Table 7.2b Electricity Net Generation: Electric Power Sector (2015), *available at http://www.eia.gov/totalenergy/data/browser/xls.cfm?tbl=T07.02B&freq=m.*

3. Basis for Magnitude of Generation Shift

a. *Technical feasibility of NGCC units to generate at 75% of their capacity.*

In order to estimate the potential magnitude of the opportunity to reduce power sector CO_2 emissions through shifting generation among existing EGUs, the EPA first examined information on the design capabilities and availability of NGCC units. Availability is defined as the number of hours that generators are available to generate electricity, and it is typically expressed as a percentage of the total number of hours in a year. Since the value of NGCC capacity is related to how much electricity the owner of that capacity can generate and sell, units are typically designed with very high availability ratings. Baseload units have annual average availabilities of approximately 91%–92%, and peaking units are generally available 96% to 98% of peak hours.[662] The EPA also examined information on the historical availability of NGCC units in practice. This examination showed that, although most NGCC units have historically been operated in intermediate-duty roles for economic reasons, they are technically capable of operating in baseload roles at much higher annual utilization rates. Average annual availability (that is, the percentage of annual hours when an EGU is not in a forced or maintenance outage) for NGCC units in the U.S. generally exceeds 85 percent, and can exceed 90 percent for some groups.[663]

We also researched historical data to determine the utilization rates that NGCC units have already demonstrated their capability to sustain. Over the last several years, the utilization patterns of fossil fuel-fired units have shifted relative to historical dispatch patterns, with NGCC units increasing generation and many coal-fired EGUs reducing generation. In fact, in April 2012, for the first time ever the total quantity of electricity generated nationwide from natural gas was approximately equal to the total quantity of electricity generated nationwide from coal.[664] These changes in generation patterns have been driven largely by changes over time in the relative prices of natural gas and coal. Although the relative fuel prices vary by location, as do the recent generation patterns, this trend holds across broad regions of the U.S. In the aggregate, the historical data provide ample evidence indicating that, on average, existing NGCC units can achieve and sustain utilization rates higher than their historical average utilization rates.

Utilization of EGUs is often considered using the metric of a capacity factor, which is the percentage of total production potential that an electric generating unit achieves in a given time period. A capacity factor of 75 percent thus represents a unit producing three-quarters of the electricity it could have produced in that time had it utilized its entire capacity. The EPA received multiple comments regarding the proposed use of nameplate capacity in calculating the potential utilization level of existing NGCCs under building block 2. These comments stated that net summer capacity is a more meaningful and reliable metric than nameplate capacity, because net capacity best reflects the electric output available to serve load. The EPA agrees with these comments. The quantification of building block 2 as well as performance rate and state goal calculations in the final rule are all based on net summer generating capacity. An annual utilization rate of 75 percent on a net summer basis is similar to the proposed rule's consideration of 70 percent utilization on a nameplate basis.[665]

The experience of relatively heavily-used NGCC units provides an additional indication of the degree of increase in average NGCC unit utilization that is technically feasible.

The EPA reexamined the historical NGCC plant utilization rate data reported to the EIA, and found that in 2012 roughly 15 percent of existing NGCC plants operated at annual utilization rates of 75 percent or higher on a net summer basis.[666] In effect, these plants were providing baseload power. In addition to the 15 percent of NGCC plants that operated approximately at a 75 percent utilization rate on an annual basis, some NGCC plants operated at even higher utilization rates for shorter, but still sustained, periods of time in response to high cyclical demand. For example, on a seasonal basis, a significant number of NGCC plants have achieved utilization rates greater than 90 percent on a net summer basis; during the summer of 2012 (June through August), about 30 percent of NGCC plants operated at utilization rates of 75 percent or more across the entire season. During the spring and fall periods when electricity demand levels are typically lower, these plants were sometimes idled or operated at much lower capacity factors. Nonetheless, the data clearly demonstrate that a substantial number of existing NGCC plants have proven the ability to sustain 75 percent utilization rates for extended periods of time. We view this as strong evidence that increasing the annual average utilization rates of existing NGCC units to 75 percent on a net summer basis would be technically feasible.

The EPA believes that an annual average utilization rate of 75 percent on a net summer basis is a conservative assessment of what existing NGCC plants are capable of sustaining for extended periods of time. In 2012, roughly 10 percent of existing NGCC plants operated at annual utilization rates of 80 percent or higher on a net summer basis. While the EPA believes this level is also technically feasible on average for the existing NGCC fleet, the EPA is quantifying building block 2 assuming an NGCC utilization level of 75% on a net summer basis in order to offer sources additional compliance flexibility, given that the extent to which they realize a utilization level beyond 75 percent will reduce their need to rely on other emission reduction measures or building blocks.

b. *Historical generation shifts to NGCC generation.*

In 2012, total electric generation from existing NGCC units was 966 TWh.[667] After the application of the building block 2 potential (increasing NGCC utilization up to a 75 percent capacity factor on a net summer basis, including generation from NGCC units that were under construction), the total generation

[662] Negotiating Availability Guarantees for Gas Turbine Plants, available at: *http://www.power-eng.com/articles/print/volume-105/issue-3/features/negotiating-availability-guarantees-for-gas-turbine-plants.html*.

[663] See, *e.g.,* North American Electric Reliability Corp., 2008–2012 Generating Unit Statistical Brochure—All Units Reporting, *http://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx;* Higher Availability of Gas Turbine Combined Cycle, Power Engineering (Feb. 1, 2011), *http://www.power-eng.com/articles/print/volume-115/issue-2/features/higher-availability-of-gas-turbine-combined-cycle.html*.

[664] *http://www.eia.gov/todayinenergy/detail.cfm?id=6990*.

[665] For a given amount of net generation, a net summer capacity factor appears higher compared to a corresponding nameplate capacity factor because net summer capacity reflects a lower amount of total generation potential achievable by the unit in practice.

[666] Net summer capacity is defined as: ''The maximum output, commonly expressed in megawatts (MW), that generating equipment can supply to system load, as demonstrated by a multi-hour test, at the time of summer peak demand (period of June 1 through September 30.) This output reflects a reduction in capacity due to electricity use for station service or auxiliaries.'' (EIA, *http://www.eia.gov/tools/glossary*).

[667] Appendix 1, CO_2 Emission Performance Rate and Goal Computation Technical Support Document for CPP Final Rule.

from these existing sources is assumed to be 1,498 TWh.[668]

The EPA believes that producing this quantity of generation from this set of NGCC units is feasible. To put this level of generation into context, NGCC generation increased by approximately 439 TWh (an 83 percent increase) between 2005 and 2012. The EPA calculates that assumed NGCC generation in 2022 through the quantification of building block 2 potential is approximately 44 percent higher than 2014 levels. This reflects a smaller growth rate in potential NGCC generation between 2015 and 2022 than has been observed in practice from 2005 to 2012, a time period of the same duration.

c. *Reliability.*

We also expect that an increase in NGCC generation of this amount would not impair power system reliability. Sources can achieve increases in utilization of existing NGCCs that displace generation from steam sources without impacting reliability because this shift in average annual utilization across existing EGUs does not inhibit the power sector's ability to maintain adequate dispatchable resources to continue to meet reserve margins and maintain reliability. Furthermore, sources are not required to achieve the exact or even the full extent of the building block 2 generation shift itself, which means that sources will have ample flexibility to maintain reliability-relevant operations while achieving emission reductions through a variety of measures.[669]

d. *Natural gas infrastructure.*

The EPA also examined the technical capability of the natural gas supply and delivery system to provide increased quantities of natural gas and the capability of the electricity transmission system to accommodate shifting generation patterns. For several reasons, we conclude that these systems would be capable of supporting the degree of increased NGCC utilization potential in building block 2. First, the natural gas pipeline system is already supporting national average NGCC utilization rates of 60 percent or higher during peak hours, which are the hours when constraints on pipelines or electricity transmission networks are most likely to arise. NGCC unit utilization rates during the range of peak daytime hours from 10 a.m. to 9 p.m. are typically 15 to 20 percentage points above their average utilization rates (which have recently been in the range of 40 to 50 percent).[670] Fleet-wide combined-cycle average monthly utilization rates have reached 65 percent,[671] showing that the pipeline system can currently support these rates for an extended period. If the current pipeline and transmission systems allow these utilization rates to be achieved in peak hours and for extended periods, it is reasonable to expect that similar utilization rates should also be possible in other hours when constraints are typically less severe, and be reliably sustained for other months of the year. Furthermore, the NGCC utilization increase assumed in building block 2 could occur without a significant impact on peak demand for natural gas, including winter demand (when the power sector's demand for natural gas competes with other sectors' demands for natural gas), since increasing annual utilization of NGCCs could focus on non-peak periods when NGCC capacity factors are currently low.

The second consideration supporting a conclusion regarding the adequacy of the gas supply infrastructure is that pipeline and transmission planners have repeatedly demonstrated the ability to methodically relieve bottlenecks and expand capacity.[672] Natural gas pipeline capacity has regularly been added in response to increased gas demand and supply, such as the addition of large amounts of new NGCC capacity from 2001 to 2003, or the delivery to market of unconventional gas supplies since 2008. These pipeline capacity increases have added significant deliverability to the natural gas pipeline network to meet the potential demands from increased use of existing NGCC units. Over a longer time period, much more significant pipeline expansion is possible. In previous studies, when the pipeline system was expected to face very large demands for natural gas use by electric utilities, the pipeline industry projected that increases of up to 30 percent in total deliverability out of the pipeline system would be possible.[673] There have been notable pipeline capacity expansions over the past five years, and substantial additional pipeline expansions are currently under construction.[674] Further, the phasing in of building block 2's potential in the determination of the BSER; the flexible nature of multi-year compliance with the ultimate emission reduction requirements of the rule; and the seven years between finalization of this rule and the first year of compliance provide time for infrastructure improvements to occur should they prove necessary in some locations. Combining these factors of currently observed average monthly NGCC utilization rates of up to 65 percent, the flexibility of the emission guidelines, the rates of historical growth, and the availability of time to address any existing pipeline infrastructure limitations, it is reasonable to conclude that the natural gas pipeline system can reliably deliver sufficient natural gas supplies to allow NGCC utilization to increase up to an average annual capacity factor of 75 percent on a net summer basis.

e. *Natural gas production.*

We recognize that an increase in NGCC utilization rates at existing units corresponds with an associated increase in natural gas production, consistent with the current trends in the natural gas industry. The EPA expects the growth in NGCC generation assumed for building block 2 to be feasible and consistent with the production potential of domestic natural gas supplies. Increases in the natural gas resource base have led to fundamental changes in the outlook for natural gas. There is general agreement that recoverable natural gas resources will be substantially higher for the foreseeable future than previously anticipated, exerting downward pressure on natural gas prices. According to EIA, proven natural gas reserves have doubled between 2000 and 2012. Domestic dry gas production has increased by 25 percent over that same timeframe (from 19.2 TCF in 2000 to 24.0 TCF in 2012).

[668] Appendix 1, CO_2 Emission Performance Rate and Goal Computation Technical Support Document for CPP Final Rule.

[669] See section VIII for further discussion of electric reliability planning.

[670] EIA, Average utilization of the nation's natural gas combined-cycle power plant fleet is rising, Today in Energy, July 9,2011, *http://www.eia.gov/todayinenergy/detail.cfm?id=1730#;* EIA, Today in Energy, Jan. 15, 2014, *http://www.eia.gov/todayinenergy/detail.cfm?id=14611* (for recent data).

[671] EIA, Electric Power Monthly, February, 2014. Table 6.7.A.

[672] See, *e.g.,* EIA, Natural Gas Pipeline Additions in 2011, Today in Energy, *available at http://www.eia.gov/todayinenergy/detail.cfm?id=5050;* INGAA Foundation, Pipeline and Storage Infrastructure Requirements for a 30 Tcf Market (2004 update), *available at http://www.ingaa.org/Foundation/Foundation-Reports/Studies/FoundationReports/45.aspx;* INGAA Foundation, North American Midstream Infrastructure Through 2035—A Secure Energy Future Report (2011), *available at http://www.ingaa.org/File.aspx?id=14911.*

[673] Pipeline and Storage Infrastructure Requirements for a 30 Tcf Market, INGAA Foundation, 1999 (Updated July, 2004); U.S. gas groups confident of 30-tcf market, Oil and Gas Journal, 1999.

[674] For example, between 2010 and April 2014, 118 pipeline projects with 44,107 MMcf/day of capacity (4,699 miles of pipe) were placed in service, and between April 2014 and 2016 an additional 47 pipeline projects with 20,505 MMcf/day of capacity (1,567 miles of pipe) are scheduled for completion. Energy Information Administration, *http://www.eia.gov/naturalgas/data.cfm.*

EIA's Annual Energy Outlook Reference Case for 2015 projects that production will further increase to 29.5 TCF by 2022 and 33 TCF by 2030, as a result of increased supplies and favorable market conditions. In the AEO 2015 high oil and gas resource case, production is projected to increase to 42.7 TCF in 2030. For comparison, building block 2 assumes NGCC generation growth of 235 TWh from 2012 to reach the level assumed for 2022, and that NGCC generation growth would result in increased gas consumption of less than 2 TCF for the electricity sector, which is less than EIA's projected increase in natural gas production of 5.5 TCF from 2012 to 2022.

The EPA has also assessed the ability of the electricity and natural gas industries to achieve the potential quantified for building block 2 using the Integrated Planning Model (IPM). IPM is a multi-regional, dynamic, deterministic linear programming model of the U.S. electric power sector that the EPA has used for over two decades to evaluate the economic and emission impacts of prospective environmental policies. To inform its projections of least-cost capacity expansion and electricity dispatch, IPM incorporates representations of constraints related to fuel supply, bulk power transmission capacity, and unit availability. The model includes a detailed representation of the natural gas pipeline network and the capability to project economic expansion of that network based on pipeline load factors. At the EGU level, IPM includes detailed representations of key operational limitations such as turn-down constraints, which are designed to account for the cycling capabilities of EGUs to ensure that the model properly reflects the distinct operating characteristics of peaking, cycling, and base load units.

As described in more detail below, the EPA used IPM to assess the costs of increasing generation from existing NGCC capacity. IPM was able to meet average NGCC utilization rates of 75 percent on a net summer basis, while observing the market, technical, and regulatory constraints represented in the model. This modeling also demonstrates the ability of domestic natural gas supplies to increase their production levels, and deliver that supply through the pipeline network, to support the level of NGCC generation quantified in building block 2. Such a result is consistent with the EPA's determination that increasing the average utilization rate of existing NGCC units to 75 percent would be technically feasible.

f. *Transmission planning and construction.*

Achieving the generation shift quantified in building block 2 would not impose significant additional burden on the transmission planning process and does not necessitate major construction projects. Two considerations are important for this conclusion:

First, building block 2 applies only to increases in generation at *existing* NGCC facilities and does not contemplate any connection of new capacity to the bulk power grid. Second, regional grids are already supporting operation of the NGCC units for sustained periods of time at the capacity factors quantified in building block 2.[675] Although some upgrades to the grid (including potential, but modest, expansions of transmission capacity) may be necessary to support the extension of the time that these capacity factors are sustained over the course of the annual time period on which building block 2 is based, such upgrades are part of the normal planning process around the increased use of existing facilities. In fact, the electric transmission system is currently undergoing substantial expansion.[676] Consequently, EPA does not believe that achieving the generation shift potential in building block 2 would necessitate any significant additional requirements for transmission planning and construction beyond those already being addressed at routine intervals by the power sector. Furthermore, the phasing in of building block 2's potential in the determination of the BSER; the flexible nature of multi-year compliance with the ultimate emission reduction requirements of the rule; and the seven years between finalization of this rule and the first year of compliance all provide time for infrastructure improvements to occur should they prove necessary in some locations.

g. *Regulatory flexibility.*

The final consideration supporting our view that natural gas and electricity system infrastructure would be capable of supporting increased NGCC unit utilization rates at a maximum of 75% on a net summer basis is the substantial unit-level compliance flexibility of the emission guidelines. The final rule does not require any particular NGCC unit to achieve any particular utilization rate in any specific hour or year. Thus, even if isolated natural gas or electricity system constraints were to limit NGCC unit utilization rates in certain locations in certain hours, this would not prevent an increase in NGCC generation overall across a state or broader region and across all hours on the order assumed in the generation shift potential quantified for building block 2.

4. Cost

Having established the technical feasibility and quantification of the potential to replace incremental generation at higher-emitting EGUs with generation at NGCC facilities as a CO_2 emissions reduction strategy, we next turn to the question of cost. The cost of the power sector CO_2 emission reductions that can be achieved through shifting generation among existing fossil fuel-fired EGUs depends on the relative variable costs of electricity production at EGUs with different degrees of carbon intensity. These variable costs are driven by the EGUs' respective fuel costs and by the efficiencies with which they can convert fuel to electricity (*i.e.,* their heat rates). Historically, natural gas has had a higher cost per unit of energy content (*e.g.,* MMBtu) than coal in most locations, but for NGCC units this disadvantage in fuel cost per MMBtu relative to coal-fired EGUs is typically offset in significant part, and sometimes completely, by a technological heat rate advantage.

To consider the cost implications of building block 2, the EPA expanded upon the proposal's extensive analysis of the magnitude and cost of CO_2 emission reductions through generation shifting within defined areas (consistent with the application of building blocks for performance rate- and state goal-setting), without consideration of the availability of other emission reduction methods ultimately available to units for compliance.

To evaluate how EGU owners and grid operators could respond to a state plan's possible requirements, signals, or incentives to shift generation from more carbon-intensive to less carbon-intensive EGUs, the EPA analyzed a series of scenarios in which the fleet of NGCC units within each of the regions considered for quantifying BSER (*i.e.,* the three interconnections) was directed to achieve a specified average annual utilization rate across that region on a net basis while maintaining a fixed level of aggregate generation in that region

[675] See Greenhouse Gas Mitigation Measures TSD for a discussion of regional NGCC capacity factors.

[676] According to the Edison Electric Institute, member companies are planning over 170 projects through 2024, with costs totaling approximately $60.6 billion (this is only a portion of the total transmission investment anticipated). Approximately 75 percent of the reported projects (over 13,000 line miles) are high voltage (345 kV and higher). Construction of transmission lines of 345KV and above are generally major projects that are particularly effective at carrying power of large distances. *http://www.eei.org/issuesandpolicy/transmission/Documents/Trans_Project_lowres_bookmarked.pdf.*

across all existing fossil fuel-fired sources. The EPA conducted such scenarios to address average utilization rates of 70 percent, 75 percent and 80 percent on a net basis, allowing for shifting of fossil generation between existing units within the regions described above. This scenario identifies a generation pattern that would meet electricity demand at the lowest total cost, subject to all other specified operating and bulk power transfer constraints for the scenario, including the specified average NGCC unit utilization rate.

The costs of the various scenarios were evaluated by comparing the total costs and emissions from each scenario to the costs and emissions from a base case scenario. For the scenario reflecting a 75 percent NGCC utilization rate on a net basis with regional fossil generation shifting, comparison to the base case indicates that the average cost of the CO_2 reductions achieved over the 2022–2030 period was $24 per short ton of CO_2. We view these estimated costs as reasonable and therefore as supporting the use of a 75 percent net utilization rate target for purposes of quantifying the emission reductions achievable at a reasonable cost through the application of building block 2 in the BSER.

We also conclude from these analyses that potential impacts to fuel prices and electricity prices from achieving the extent of fossil generation shifting quantified for this building block are reasonably within the bounds of power sector experience. For example, in the 75 percent NGCC unit utilization rate scenario where generation shifting is limited to regional boundaries, the delivered natural gas price was projected to increase by an average of 7 percent over the 2022–2030 period, which is well within the range of historical natural gas price variability.[677] Projected wholesale electricity price increases over the same period were less than 4 percent, which similarly is well within the range of historical electric price variability. These projected impacts on prices were captured in the emission reduction costs of these scenarios already described above, which are reasonable and support use of a 75 percent NGCC utilization rate target for purposes of quantifying the emission reductions achievable through application of the BSER.

However, we also note that the costs (and their incorporated price impacts) just described are higher than we would expect to actually occur in real-world compliance with the final rule's compliance requirements for the following reasons. First, this analysis does not capture the building block 2 phase-in, which assumes an average utilization rate over the interim period of less than 75 percent in all three interconnections. Second, the analysis overstates the extent to which building block 2 is ultimately reflected in the source category performance rates. While the performance rate computation procedure assumes a maximum NGCC utilization rate of 75 percent on a net summer basis, the Eastern Interconnection's realization of this level of NGCC utilization yields higher source category performance rates for steam than what would have been calculated for units in the Western Interconnection and Texas Interconnection if they realized that maximum NGCC utilization rate in conjunction with the other building blocks. In other words, there is substantial building block 2 potential in the Western Interconnection and Texas Interconnection that is not actually captured in the source category performance rates that are ultimately assigned to steam through this rate- and goal-setting approach (where the performance rates are ultimately determined by the BSER region with the highest rate outcome in the calculation). Therefore, the building block 2 analysis overstates the cost of this component of BSER to the extent that it assumes achievement of this generation shift potential that is not reflected in the source category performance rates ultimately determined. Third, as a practical matter, sources will be able to achieve additional emission reductions through other measures that may prove to be less costly than generation shifting and could substitute for the reductions and costs considered here. These building block 2 analyses were focused on evaluating the potential impacts of fossil generation shifting in isolation, and as a result, they do not consider states' and sources' flexibility to choose among alternative CO_2 reduction strategies that could offer lower-cost reductions, instead of relying on fossil generation shifting to the extent analyzed here.

Based on the analyses summarized above, the EPA concludes that an average annual utilization rate for each region's NGCC units of up to 75 percent is a technically feasible, cost-effective, and adequately demonstrated building block for BSER.

For further information on the analysis discussed in this section, see Chapter 3 of the GHG Mitigation Measures TSD for the CPP Final Rule.

5. Major Comments and Responses

The EPA received numerous comments regarding building block 2. Many of these comments provided helpful information and insights and have resulted in improvements to the rule. This section summarizes some of these comments, and the remainder of the comments are responded to in the Response to Comment document, available in the docket.

The EPA received comment regarding the potential for an increase in upstream methane emissions from increased utilization of natural gas. Our analysis found that the net upstream methane emissions from natural gas systems and coal mines and CO_2 emissions from flaring of methane will likely decrease under the Clean Power Plan. Furthermore, the changes in upstream methane emissions are small relative to the changes in direct emissions from power plants. The technical details supporting this analysis can be found in the Regulatory Impact Analysis.

Commenters also expressed concern that neither a utility nor any state agency controls dispatch in most states. The EPA believes these comments fail to adequately appreciate that the utilities do control the dispatch of units that they own and/or operate, either by being the actual dispatch agent in many cases where there is no RTO or ISO that schedules the dispatch, or by the choice of units and bids they offer into an organized electricity market operated by an RTO or ISO. These entities currently control the dispatch of their units while respecting all existing requirements from environmental rules. This final rule does not change these current circumstances and makes clear that it is the EGU that is responsible for meeting the requirements in the state plan; the state is responsible for the development of that plan, but the state does not need to control the dispatch.

Other comments object to the use of a single capacity factor for all existing NGCCs to quantify building block 2 potential on the grounds that not all units may be able to achieve this utilization level, and that some units may be designed for cycling and so may need upgrades to sustain such utilization. The EPA disagrees with these comments. The 75 percent capacity factor establishes a regional potential for generation from existing NGCC capacity, and it does not establish any individual unit requirements.

Some comments argue that generation limits in permits for some existing NGCC units will limit the amount by

[677] According to EIA data, year-to-year changes in natural gas prices at Henry Hub averaged 29.9 percent over the period from 2000 to 2013. *http://www.eia.gov/dnav/ng/hist/rngwhhdA.htm.*

which these units can increase their generation and thereby limit the feasibility of building block 2. The EPA disagrees with these comments. Although permit limits can constrain the ability of individual units to operate above certain levels, building block 2 was developed conservatively, with units operating on average at a level below the maximum levels at which some units have demonstrated the capability to operate. No individual unit is required to achieve the average generation levels used to quantify building block 2. Further, permit limits at individual units can be considered when state plans are developed. There are many flexibilities in the final rule, including the opportunity to establish standards of performance that incorporate emissions trading or develop plans that will respect any existing permit limits at individual units.

The EPA also received comments asserting that increasing generation from new renewables would require increased use of natural gas capacity for back-up and ramping, and therefore it is not possible for NGCC units to run at BSER utilization rates and also be available to support the additional variable renewable generation resulting from building block 3. The EPA disagrees with this comment. The 75% net summer utilization rates defined by building block 2 is a conservative assessment and applied on an annual average basis. It is therefore possible for these existing units to both operate at higher annual utilization rates, and also to operate at higher rates during limited periods and still maintain a 75% net summer average annual utilization rate. While variable renewable generation does require additional load following and ramping resources and unit cycling, these requirements are generally a small part of the overall ramping costs of the system (see NREL, Relevant Studies for NERC's Analysis of EPA's Clean Power Plan 111(d) Compliance). Additionally, while existing NGCC units are an efficient source of ramping to support variable renewables, other units running in an intermediate mode can also provide load following and ramping.

E. Building Block 3—New Zero-Emitting Renewable Generating Capacity

The third element of the foundation for the EPA's BSER determination for reducing CO_2 emissions at affected fossil fuel-fired EGUs entails an analysis of the extent to which generation at the affected EGUs can be replaced by using an expanded amount of zero-emitting renewable electricity (RE) generating capacity to produce replacement generation.

In this section we address first the history of and then trends in RE development, as well as the importance of expanding the use of RE. Next we discuss the ability of affected EGUs to access generation from new RE generating capacity, followed by a discussion of renewable energy certificate (REC) markets. We then describe the quantification of the amount of generation from new RE generating capacity achievable through building block 3, including key comments, changes made from the proposal, the method by which RE target generation levels are quantified, and the magnitude and timing of increases in RE generation associated with this building block. Next, we discuss the feasibility of implementing the identified incremental amounts of RE generation. Finally, we address the costs associated with those increases in RE generation.

1. History of RE Development

RE generating technologies are a well-established part of the utility power sector. These technologies generate electricity from renewable resources, such as wind, sun and water. While RE has been used to generate electricity for over a century, the push to commercialize RE more broadly began in the 1970s.[678] Following a series of energy crises, new federal organizations and initiatives were established to coordinate energy policy and promote energy self-sufficiency and security, including solar energy legislation, the Public Utility Regulatory Policies Act of 1978 (PURPA) and the 1980 Energy Security Act.[679]

PURPA was a key step in stimulating RE development. By requiring utilities to purchase generation from qualifying facilities (*i.e.,* certain CHP and RE generators) at avoided costs, PURPA opened electricity markets to more RE generation and gave rise to non-utility generators that were willing to try new RE technologies.[680] In addition, since 1992, federal tax policy has provided important financial support via tax credits for the production of RE and investments in RE.

States have also taken a significant lead in requiring the development of RE resources. In particular, a number of states have adopted renewable portfolio standards (RPS), which are regulatory mandates to increase production of RE. As of 2013, 29 states and the District of Columbia had enforceable RPS or similar laws.[681] These RPS requirements continue to drive robust near-term growth of non-hydropower RE.

2. Trends in RE Development

Today, RE is tightly integrated with the utility power sector in multiple ways: States have set RE targets for electrical load serving entities; utilities themselves are diversifying their portfolios by contracting with RE generators; and new RE generators are being developed to provide more electrical power grid support services beyond just energy (*e.g.,* modern electronics allow wind turbines to provide voltage and reactive power control at all times).[682] [683]

Use of RE continues to grow rapidly in the U.S. In 2013, electricity generated from RE technologies, including conventional hydropower, represented 12 percent of total U.S. electricity, up from 8 percent in 2005.[684] In 2013, U.S. non-hydro RE capacity for the total electric power industry exceeded 80,000 megawatts, reflecting a fivefold increase in just 15 years.[685] In particular, there has been substantial growth in the wind and solar photovoltaic (PV) markets in the past decade. Since 2009, U.S. wind generation has tripled and solar generation has grown twentyfold.[686]

The global market for RE is projected to grow to $460 billion per year by

[678] Nearly all U.S. hydroelectric capacity was built before the mid-1970s. U.S. DOE. History of Hydropower. Accessed March 2015. Available at: *http://energy.gov/eere/water/history-hydropower.*

[679] U.S. DOE Office of Management, Timeline of Events: 1971–1980. Accessed March 2015. Available at: *http://energy.gov/management/office-management/operational-management/history/doe-history-timeline/timeline-events-1.*

[680] ''Restructuring or Deregulation?'' Smithsonian Museum of American History. Accessed March 2015. Available at: *http://americanhistory.si.edu/powering/dereg/dereg1.htm.*

[681] Energy Information Administration, Annual Energy Outlook 2014 with Projections to 2040, at LR–5 (2014).

[682] IPCC, Renewable Energy Sources and Climate Change Mitigation, 2012. Accessed March 2015. Available at: *http://www.ipcc.ch/pdf/special-reports/srren/SRREN_Full_Report.pdf.*

[683] American Wind Energy Association. AWEA Comments on EPA's Proposed Carbon Pollution Emission Guidelines for Existing Stationary Sources and Supplemental Proposed Rule. p. 107.

[684] Energy Information Administration, Monthly Energy Review, May 2015, Table 7.2b. Available at: *http://www.eia.gov/totalenergy/data/monthly/pdf/sec7_6.pdf.*

[685] Non-hydro RE capacity for the total electric power industry was more than 16,000 megawatts in 1998. Energy Information Administration, 1990–2013 Existing Nameplate and Net Summer Capacity by Energy Source Producer Type and State (EIA–860). Available at: *http://www.eia.gov/electricity/data/state/.*

[686] Energy Information Administration, Monthly Energy Review, May 2015, Table 7.2b. Available at: *http://www.eia.gov/totalenergy/data/monthly/pdf/sec7_6.pdf.*

2030.[687] RE growth is further spurred by the significant amount of existing natural resources that can support RE production in the U.S.[688] In the Energy Information Administration's Annual Energy Outlook 2015, RE generation grows substantially from 2013 to 2040 in the reference case and all alternative cases.[689] In the reference case, RE generation increases by more than 70 percent from 2013 to 2040 and accounts for over one-third of new generation capacity.[690]

The recent and projected growth of RE is in part a reflection of its increasing economic competitiveness. Numerous studies have tracked capital cost reductions and performance improvements for RE, particularly for solar and wind. For instance, Lazard's analysis of wind and utility-scale solar PV levelized costs of energy (LCOE), on an unsubsidized basis, over the last five years found the average percentage decrease of high and low of LCOE ranges were 58 percent and 78 percent, respectively.[691] Analyses of wind's competitiveness found falling wind turbine LCOE while the wind industry developed projects at lower wind speed sites using new turbine designs (*e.g.,* increased turbine hub heights and rotor diameters). Performance improvements have come from novel deployments of new turbines designed for lower quality wind sites that are deployed at higher quality wind sites, which have resulted in capacity factor increases for these locations.[692] [693] For utility-scale solar, cost and performance have also improved significantly. Analysis has shown that the installed price of solar photovoltaics (PV) systems, prior to any incentives, has declined substantially since 1998. Capacity-weighted average prices of solar PV in utility-scale deployments were 40 percent lower in 2013 than five years earlier.[694] [695] Initially, price declines were partially driven by oversupply and manufacturers' thin margins, but, in 2014, prices have remained low due to reductions in manufacturing costs.[696] The capacity factors of new utility-scale installations have increased as systems are optimized to maximize energy production. For example, a growing number of utility-scale PV systems are increasing the direct current capacity of the solar array relative to the alternating current rating of the array's inverter to increase energy production and improve project economics.[697] The cost and performance improvements for wind and solar are driven by increased scale of production, improved technologies, and advancements in system deployments.

3. Importance of Increasing Use of RE

Currently, the utility power sector accounts for 40 percent of total annual energy consumption in the U.S.[698] Introducing more zero-emitting RE generation over the long term could significantly reduce CO_2 emissions, as production of RE predominantly replaces fossil fuel-fired generation and thereby avoids the emissions from that replaced generation.

A number of studies and recent policy developments have acknowledged RE as an important means of achieving CO_2 reductions. California cited the reduction of CO_2 emissions from electrical generations as one of the reasons for increasing its RE target from 20 percent to 33 percent by 2020 (and potentially 50 percent by 2030).[699] A recent IPCC report also concluded that RE has large potential to mitigate CO_2 emissions.[700]

Increased use of RE provides numerous benefits in addition to lower CO_2 emissions. RE typically consumes less water than fossil fuel-fired EGUs. Wind power and solar PV systems do not require the use of any water to generate electricity; water is only needed for cleaning to ensure efficient operation. In contrast, utility boilers, in particular, require large quantities of water for steam generation and cooling.[701]

Increasing RE use will also continue to lower other air pollutants (*e.g.,* fine particles, ground-level ozone, etc.). In addition, the RIA notes that increasing RE will diversify energy supply, hedge against fossil fuel price increases and create economic development and jobs in manufacturing, installation, and other sectors of the economy.

4. Access to RE by Owners of Affected EGUs

The ability of affected EGUs to co-locate or obtain incremental RE to reduce CO_2 emissions is well-demonstrated, whether it is through direct ownership, bilateral contracts, or procurement of the environmental attributes associated with RE generation.[702] Consequently, the EPA believes that an increase in RE is a proven way to reduce CO_2 emissions at affected EGUs of all types at a reasonable cost.

Owners and operators of affected EGUs across the U.S. already have substantial opportunities to procure RE regardless of their organizational structure and/or business model. In many parts of the country, EGUs are owned and operated by vertically integrated utilities. These utilities can be investor-owned utilities that operate under traditional electricity regulation, municipal utilities (munis), or electric cooperatives (co-ops). These utilities have significant control over the types of generating capacity they develop or acquire, and over the electricity mix used to meet demand within their service territories.

Even when EGU owners participating in organized markets do not directly determine dispatch among energy sources, such EGU owners make

[687] "Global Renewable Energy Market Outlook." Bloomberg New Energy Finance, November 16, 2011. Available at *http://bnef.com/WhitePapers/download/53.*

[688] Lopez et al., NREL, "U.S. Renewable Energy Technical Potentials: A GIS-Based Analysis," (July 2012). Available at *http://www.nrel.gov/docs/fy12osti/51946.pdf.*

[689] Energy Information Administration, Annual Energy Outlook 2015 with Projections to 2040 (2015), p. 25. Available at *http://www.eia.gov/forecasts/aeo/pdf/0382(2015).pdf.*

[690] Energy Information Administration, Annual Energy Outlook 2015 with Projections to 2040 (2015), p. ES–6–7. Available at *http://www.eia.gov/forecasts/aeo/pdf/0382(2015).pdf.*

[691] Lazard, *Levelized Cost of Energy Analysis-Version 8.0,* September 2014, p. 9, Available at: *http://www.lazard.com/media/1777/levelized_cost_of_energy_-_version_80.pdf.*

[692] "2013 Wind Technologies Market Report," LBNL, August 2014. Available at *http://emp.lbl.gov/sites/all/files/2013_Wind_Technologies_Market_Report_Final3.pdf.*

[693] "2013 Cost of Wind Energy Review," NREL, Feb 2015. Available at: *http://www.nrel.gov/docs/fy15osti/63267.pdf.*

[694] "Tracking the Sun VII" LBNL, Sept 2014. Available at: *http://emp.lbl.gov/publications/tracking-sun-vii-historical-summary-installed-price-photovoltaics-united-states-1998-20.*

[695] "Photovoltaic System Pricing Trends," NREL, 22 Sept 2014. Available at: *http://www.nrel.gov/docs/fy14osti/62558.pdf.*

[696] "Revolution Now—The Future Arrives for Four Clean Energy Technologies—2014 Update," DOE, Oct 2014. Available at: *http://energy.gov/sites/prod/files/2014/10/f18/revolution_now_updated_charts_and_text_october_2014_1.pdf.*

[697] "Utility-Scale Solar 2013," LBNL, Sept 2014. Available at: *http://emp.lbl.gov/publications/utility-scale-solar-2013-empirical-analysis-project-cost-performance-and-pricing-trends.*

[698] U.S. Energy Information Administration Annual Energy Review, 2011. Accessed March 2015. Available at: *http://www.eia.gov/totalenergy/data/monthly/pdf/flow/primary_energy.pdf.*

[699] California S.B. 2 (1X), 2011. Accessed March 2015. Available at: *http://www.leginfo.ca.gov/pub/11-12/bill/sen/sb_0001-0050/sbx1_2_bill_20110412_chaptered.pdf.*

[700] IPCC, Renewable Energy Sources and Climate Change Mitigation, 2012. Accessed March 2015. Available at: *http://www.ipcc.ch/pdf/special-reports/srren/SRREN_Full_Report.pdf.*

[701] EPA, Water Resource Use. Accessed on March 2015. Available at: *http://www.epa.gov/clean energy/energy-and-you/affect/water-resource.html.*

[702] Refer to the GHG Mitigation Measures TSD for additional information on RE ownership and co-location.

decisions about what types of capacity they choose to develop and thus what generation mix they can ultimately supply into that market's dispatch choices. Because zero-emitting RE technologies have relatively low variable costs, an EGU owner's decision to install (or to finance the installation of) RE capacity will yield lower-cost electricity generation that, when available, a system dispatcher will prefer over higher-variable-cost generation from fossil fuel-fired capacity. Therefore, all owners of affected EGUs have a direct path for replacing higher-emitting generation with RE regardless of their organizational type and regardless of whether they operate in a cost-of-service framework or in a competitive, organized market.

Many affected EGUs have already directly invested in RE. Of the 404 entities that owned part of at least one affected EGU under this rule, 178 also owned RE (biomass, geothermal, solar, water or wind). These 178 owners owned 82 percent of affected EGU capacity. As a whole, these entities' share of RE capacity was equal to 25 percent of the total of their affected EGU capacity.[703]

Some of the largest owners of affected EGUs also owned RE (see Table 8). For example, NRG Energy, Inc. owns more than 3,000 megawatts of RE capacity, over 20 percent of which (nearly 800 megawatts) is solar, and almost 80 percent of which (over 2,500 megawatts) is wind. Duke Energy Corporation owns 175 megawatts of solar and over 1,500 megawatts of wind. NextEra Energy, Inc.'s share of RE capacity approaches 40 percent of their total affected EGU capacity.[704] Table 8 lists a sampling of affected EGUs that have large amounts of fossil fuel-fired capacity and RE capacity:

TABLE 8—SAMPLE OF OWNERS OF AFFECTED EGUS AND RE CAPACITY [705] [706]

Ultimate parent	Affected EGU capacity (MW)	Renewable capacity (MW)
NRG Energy, Inc	48,787	3,149
Duke Energy Corporation	39,028	5,526
Southern Company	37,168	3,245
American Electric Power Company, Inc	34,940	1,142
NextEra Energy, Inc	29,471	11,626
Calpine Corporation	23,878	1,509
Tennessee Valley Authority	21,717	5,427
Berkshire Hathaway Inc	18,899	6,650
FirstEnergy Corp.	16,175	1,371
Exelon Corporation	10,283	3,361
Nebraska Public Power District	2,003	90
Basin Electric Power Cooperative	1,526	275
American Municipal Power, Inc	1,112	53
Sacramento Municipal Utility District	925	834
Golden Spread Electric Cooperative, Inc	521	78

Large vertically integrated utilities generally have multiple options for investing in RE, including building their own RE capacity or procuring RE under a long-term power purchase agreement. Municipal utilities and rural cooperatives that own generating asset portfolios, particularly generation and transmission cooperatives and larger municipal utilities, have also used RE to reduce carbon emissions. Large generation and transmission cooperatives also purchase significant quantities of RE for their members. Federal power authorities own or contract for significant amounts of RE.[707] [708]

The list of ten electric utilities with the largest amounts of wind power capacity on the system (owned or under contract) includes a variety of affected EGU organizational structures, including vertically integrated investor-owned utilities, municipal utilities, and federal power authorities. Xcel Energy and Berkshire Hathaway Energy rank first and second with 5,736 megawatts and 4,992 megawatts of wind capacity, respectively. Tennessee Valley Authority, a federal power authority, had 1,572 megawatts and CPS Energy, a public utility, had 1,059 megawatts of wind power capacity.[709] Basin Electric Power Cooperative had 716 megawatts and was the top ranked cooperative utility, but is not on the top ten utilities with wind power capacity list.

Many affected EGUs are already planning on deploying significant amounts of RE according to their integrated resource plans (IRPs). Electric utilities use IRPs to plan operations and investments over long time horizons. These plans typically cover 10 to 20 years and are mandated by public utility commissions (PUCs). A recent study of IRPs, included in the docket for this rulemaking, shows this trend.[710] For instance, Dominion plans for over 800 megawatts of wind and solar in their 2015 to 2029 planning period.[711] Duke Energy Carolinas' IRP has no plans for new coal, but describes plans for roughly 1,250 megawatts of additional RE by 2021, and approximately 2,150 megawatts by 2029. A significant

[703] SNL Energy. Data used with permission. Accessed on June 9, 2015.

[704] Ibid.

[705] SNL Energy. Data used with permission. Accessed on June 9, 2015.

[706] eGRID, EPA. 2012 Unit-Level Data Using the eGRID Methodology.

[707] American Wind Energy Association. AWEA Comments on EPA's Proposed Carbon Pollution Emission Guidelines for Existing Stationary Sources and Supplemental Proposed Rule. pp. 88–91.

[708] Solar Energy Industries Association. Comments to the EPA and States on the Proposed Clean Power Plan Regulating Existing Power Plants Under Section 111(d) of the Clean Air Act. pp. 98–147.

[709] American Wind Energy Association. U.S. Wind Industry Annual Market Report (2014 data). Accessed July 2015. Available at *http://www.awea.org/AnnualMarketReport.aspx?ItemNumber=7422&RDtoken=64560&userID=*. The ten largest electric utilities with wind power capacity on the system (owner or under contract) includes: Xcel Energy; Berkshire Hathaway Energy; Southern California Edison; American Electric Power; Pacific Gas & Electric; Tennessee Valley Authority; San Diego Gas & Electric; CPS Energy; Los Angeles Department of Water & Power; and Alliant Energy.

[710] See memo entitled ''Review of Electric Utility Integrated Resource Plans'' (May 7, 2015).

[711] Dominion North Carolina Power's and Dominion Virginia Power's Report of Its Integrated Resource Plan, August 2014. Available at: *https://www.dom.com/library/domcom/pdfs/corporate/integrated-resource-planning/nc-irp-2014.pdf.*

portion (1,670 megawatts) of the planned RE is solar.[712] Ameren is planning to retire one-third of the coal generating capacity, as well as installing an additional 400 megawatts of wind, 445 megawatts of solar, and 28 megawatts of hydroelectric generating capacity.[713]

Independent power producers (IPPs) also can and do own both RE and fossil generation. For example, NRG is a diversified IPP that operates substantial coal, natural gas, wind, solar, and nuclear capacity. NRG demonstrates the ability of IPPs to reduce utilization of fossil fuel-fired EGUs and replace that generation with RE. NRG announced a goal to cut CO_2 emissions from its fleet by 50 percent by 2030 (from a 2014 baseline).[714] NRG has already reduced CO_2 emissions from its fleet by 40 percent since 2005. This achievement demonstrates that when an IPP commits to shifting its generation portfolio, it can do so at reasonable cost and without reliability impacts. The NRG example shows that reduced utilization of fossil fuel-fired EGUs that is replaced by RE also owned by the EGU owner is adequately demonstrated.

EGU owners can also replace fossil fuel-fired generation with RE through bilateral contracts and REC purchases, as described below. Both the bilateral market for RE contracts and REC markets are well-developed. There are no legal or technical obstacles to a fossil fuel-fired EGU owner acting as the counterparty of a bilateral contract for purchase of energy from a RE facility. Any type of EGU owner (utility or otherwise) can purchase and retire RECs. The fact that RECs are purchased by a diverse set of market participants—including residential consumers, commercial businesses, and industrial facilities—demonstrates that such a purchase for all EGU owners is adequately demonstrated.

5. REC Markets

Affected EGU owners do not need to directly invest in, or own, renewable generating capacity in order to replace fossil fuel-fired generation with RE as an emission reduction measure. RECs are used to demonstrate compliance with state RE targets, such as state RPS, and also to substantiate claims stemming from RE use. RECs are tradable instruments that are associated with the generation of one megawatt-hour of RE and represent certain information or characteristics of the generation, called attributes.[715] RECs may be traded and transferred regardless of the actual energy flow.

The legal basis for RECs is established by state statutes and administrative rules. Nearly all states with a mandatory RPS have established RECs as a means of compliance. The Federal Energy Regulatory Commission (FERC) has observed that states created RECs to facilitate programs designed to promote increased use of RE, and that ''attributes associated with the [RE] facilities are separate from, and may be sold separately from, the capacity and energy.'' [716]

In complying with states' RPS requirements, utilities have contracted for RECs from in-state and out-of-state resources in accordance with RPS requirements. Utilities may have sourced RECs from out-of-state to reduce the cost of compliance, to source RECs from specific generation types, or for other reasons.[717]

The development of REC markets to facilitate RPS compliance provides evidence that markets can develop to facilitate compliance with rate-based state plans. These markets will afford affected EGU owners an alternative to directly invest in, or own, renewable generating capacity in order to replace fossil fuel-fired generation with RE as an emission reduction measure.

6. Quantification of RE Generation Potential for BSER and Major Comments

The methodology for quantifying RE generation levels under building block 3 is a modified version of the alternative RE approach from proposal, with adjustments that reflect the data and information the EPA collected through stakeholder comments and the EPA's additional analysis and information collection. In evaluating the proposed and alternative RE approaches commenters observed that RPS, as the basis for quantifying RE generation levels under the proposed approach, are policy instruments that states may choose to implement for a variety of reasons not related to CO_2 emission reductions. Additionally, differences across RPS policies in eligible resources, crediting mechanisms, deliverability requirements, alternative compliance payments, and other policy elements made the regional averaging of state-level RPS requirements challenging. Finally, commenters provided data demonstrating that RE resource potential can vary significantly within the regions identified under the proposed approach, producing state-level RE generation levels that may not be aligned with the opportunity to deploy incremental RE resources at reasonable cost. In contrast, commenters argued that a methodology similar to the alternative RE approach, which is based on economic potential, represents a more technically sound basis for quantifying building block 3 target generation levels that accounts for regional differences in RE resources and power market conditions, such as projected fuel prices, load growth and wholesale power prices. The EPA agrees with these comments.

Within the framework of the alternative RE approach, the EPA received significant comments on a number of issues, including the use of historical deployment rates, the interstate nature of RE and the power system, merits of total versus incremental RE generation as the metric by which building block 3 generation levels are quantified, types of RE technologies that contribute to those generation levels, cost and performance estimates associated with those RE technologies, magnitude of the reduced cost applied to new RE capacity as an incentive to deploy, and application of a nationally uniform benchmark development rate to modeled projections of economic deployment. Based on commenter data and information, as well as further analysis and information collection, the primary adjustments the EPA made to the alternative RE approach are:

- The basis for quantifying building block 3 generation has been modified to incorporate historical deployment patterns for RE technologies as well as the economic potential identified through modeling projections. The introduction of historical capacity additions to the final methodology further grounds building block 3 generation

[712] Duke Energy Carolinas' 2014 Integrated Resource Plan, September 2014. Available at: *http://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=c3c5cbb5-51f2-423a-9dfc-a43ec559d307.*

[713] Integrated Resource Plan Update, October 2014. Available at: *https://www.ameren.com/missouri/environment/renewables/ameren-missouri-irp.*

[714] NRG, ''NRG Energy Sets Long-Term Sustainability Goals at Groundbreaking of 'Ultra-Green' New Headquarters'' (Nov. 20, 2014). Available at *http://investors.nrg.com/phoenix.zhtml?c=121544&p=irolnewsArticle&ID=1991552.*

[715] EPA Green Power Partnership, Renewable Energy Certificates July 2008). Available at *http://www.epa.gov/greenpower/documents/gpp_basics-recs.pdf.*

[716] FERC Docket No. EL03–133–000, Petition for Declaratory Order and Request for Expedited Consideration, American Ref-Fuel Company, Covanta Energy Group, Montenay Power Corporation, and Wheelabrator Technologies, Inc. June 16, 2003, *Order Granting Petition for Declaratory Ruling,* October 1, 2003. *American Ref-Fuel Co. et al.,* 105 FERC ¶ 61,004 (2003); and *Order Denying Rehearing.* April 15, 2004. 107 FERC ¶ 61,016 (2004). Available online at: *http://www.ferc.gov/whats-new/comm-meet/041404/E-28.pdf* (accessed 11/7/2014).

[717] Heeter, J. Quantifying the Level of Cross-State Renewable Energy Transactions. NREL 2015. Available at *http://www.nrel.gov/docs/fy15osti/63458.pdf.*

in demonstrated levels of RE deployment that have been successfully incorporated into the power system. This adjustment also serves to harmonize the approach across all three building blocks in which historical data is the primary basis for identifying emission reduction opportunities under the BSER.

• The RE technologies used to quantify building block 3 generation levels are onshore wind, utility-scale solar PV, concentrating solar power (CSP), geothermal and hydropower. Each of these technologies is a utility-scale, zero-emitting resource that was included under the alternative RE approach at proposal. Additionally, the EPA received significant comments on the opportunities and challenges associated with distributed RE technologies. Distributed technologies, as a demand-side resource, present unique data and technical challenges (such as the role of evaluation, measurement and verification (EM&V) procedures in verifying their production, the diverse economic incentives of different parties involved in their deployment, and the variety of grid integration policies and conditions across potential deployment sites) that complicate identifying a technically feasible and cost-effective level of generation. Consequently, the EPA is, at this time, choosing not to include distributed technologies as part of the BSER (although, as explained in section VIII.K of this preamble, distributed RE technologies that meets eligibility criteria may be used for compliance). Finally, any RE technology that has not been deployed in the U.S., including demonstrated RE technologies for which there is clear evidence of technical feasibility and cost-effectiveness (*e.g.,* offshore wind), contributes no generation to building block 3 under this historically-based methodology. These RE technologies are consequently reserved for compliance, which offers affected EGUs additional flexibility and will reduce their need to rely on other emission reduction measures or building blocks.

• Building block 3 generation levels are expressed in terms of incremental, rather than total, RE generation. As a metric, incremental generation is better aligned with quantifying an amount of expanded RE to replace generation at affected EGUs.[718] Specifically, the generation levels under building block 3 include generation from capacity that commenced operation subsequent to 2012 (the data year on which the BSER is evaluated). Commenters remarked that it is unnecessary to include generation from RE capacity that was already in operation by 2012 in building block 3 because the impact of that generation on fossil fuel-fired EGUs is already reflected in the observed 2012 emissions and generation data of those EGUs.

• Due to the interstate nature of RE and the power system, and consistent with the rationale provided in the October 2014 Notice of Data Availability (NODA), building block 3 generation levels are quantified for each of the three BSER regions—the Eastern Interconnection, Western Interconnection, and Texas Interconnection—rather than at the state-level. This regionalized approach, as described in the NODA, takes into account the opportunity to develop regional RE resources and thus better aligns building block 3 generation levels with the rule's approach to allowing the use of qualifying out-of-state renewable generation for compliance.

• Commenters observed that the cost and performance estimates the EPA relied on at proposal from the Energy Information Administration's Annual Energy Outlook 2013 do not reflect the decline in cost and increase in performance that have been demonstrated by current projects, particularly in regards to wind and solar technologies. Commenters provided data from a variety of sources to support these claims, including Lawrence Berkeley National Laboratory (LBNL), the Department of Energy (DOE) and Lazard. Each of these sources supported the contention that RE technologies, particularly wind and solar, have realized gains in cost and efficiency at a scale that has altered the competitive dynamic between RE and conventional resources. As a result, it has become increasingly necessary for any long-term outlook of the utility power sector to continually assess the development of RE technology cost and performance trends. In performing this task, the EPA revised its data for onshore wind and solar technologies to reflect the mid-case estimates from the National Renewable Energy Laboratory's (NREL's) 2015 Annual Technology Baseline. The EPA selected the NREL 2015 Annual Technology Baseline (ATB) estimates based on the quality of its data as well as NREL's demonstrated success in both reflecting and anticipating RE cost and performance trends. In addition to wind and solar technologies, the EPA evaluated hydropower deployment potential based on the latest cost and performance data from NREL's Renewable Energy Economic Potential study.[719]

• The benchmark development rate that constrained cost-effective RE deployment under the alternative RE approach in the proposal has been removed from the final methodology.[720] Commenters detailed several issues with applying the benchmark development rate, including that it does not factor in the total size of the RE resource in a given state and is inconsistent with a regional approach to quantifying target generation levels. EPA agrees with these comments and the benchmark development rate has been eliminated.

In addition to the comments described above, the EPA received significant comments on a wide variety of topics related to building block 3. Many of these comments provided helpful information and insights, and have resulted in improvements to the final rule. These comments, as well as the EPA responses, are available in the Response to Comment document.

The final methodology for quantifying incremental RE target generation levels contains seven steps. Each step is described below.[721]

First, the EPA collected data for each RE technology (onshore wind, utility-scale solar PV, CSP, geothermal and hydropower) to determine the annual change in capacity over the most recent five-year period. From these data, the EPA calculated the five-year annual average change in capacity and the five-year maximum annual change in capacity for each technology.

Second, the EPA determined an appropriate capacity factor to apply to each RE technology that would be representative of expected future performance from 2022 through 2030. For this purpose the EPA relied on NREL's ATB.

Third, the EPA calculated two generation levels for each RE technology. The first generation level is the product of each technology's five-year average capacity change and the assumed future capacity factor. The second generation level is the product of each technology's five-year maximum annual capacity deployment and the assumed future capacity factor. Table 9 below shows the data and assumptions used for these calculations.

[718] Consistent with the October 2014 NODA, the final goal-setting methodology assumes replacement of affected EGU generation by incremental building block 3 generation in calculating source-specific CO_2 emission performance rates. For additional information on the goal-setting methodology, refer to Section VI.

[719] For additional information on the updated RE cost and performance assumptions used to quantify building block 3 generation, refer to the GHG Mitigation Measures TSD.

[720] The technical potential limiter was a nationally uniform, technology-specific limit on cost-effective RE deployment based on the amount of 2012 generation in a state as a share of that state's total technical potential.

[721] For supporting data, documentation, and examples for each step of the quantification methodology, refer to the GHG Mitigation Measures TSD.

TABLE 9—HISTORICAL CAPACITY CHANGES AND ASSOCIATED GENERATION LEVELS

	Assumed future capacity factor (percent)	Five-Year average capacity change (MW)	Generation associated with five year-average capacity change (MWh)	Maximum annual capacity change (MW)	Generation associated with maximum annual capacity change (MWh)
Utility-Scale Solar PV [722]	*20.7*	*1,927*	*3,494,268*	*3,934*	*7,133,601*
CSP	*34.3*	*251*	*754,175*	*767*	*2,304,590*
Onshore Wind	*41.8*	*6,200*	*22,702,416*	*13,131*	*48,081,520*
Geothermal	*85.0*	*142*	*1,057,332*	*407*	*3,030,522*
Hydropower	*63.8*	*141*	*788,032*	*294*	*1,643,131*
Total Generation	*N/A*	*N/A*	*28,796,222*	*N/A*	*62,193,363*

Fourth, the EPA quantified the RE generation from capacity commencing operation after 2012 that can be expected in 2021 (the year before this rule's first compliance period) without the imposition of this rule. Because building block 3 is focused on the ability of fossil fuel-fired EGUs to reduce their emissions by deploying incremental RE, it is reasonable to take into account the considerable amount of RE deployment that is already taking place and is projected to continue doing so before considering the additional deployment that would be motivated by this rule's mandate to reduce emissions from affected EGUs. The EPA considered its base case power sector modeling projections using IPM to quantify this component of future-year RE generation, which the EPA assumes to be 213,084,125 megawatt-hours in 2021.

Fifth, the EPA applied the generation associated with the five-year average capacity change to the first two years of the interim period. Combining the projected 2021 RE generation from capacity starting operation after 2012 with the generation increment associated with the five-year average change in capacity produces 241,880,347 megawatt-hours in 2022 and 270,676,570 megawatt-hours in 2023. The EPA believes it is appropriate to apply the generation associated with the five-year average capacity change for the first two years of the interim period to ensure adequate opportunity to plan for and implement any necessary RE integration strategies and investments in advance of the higher RE deployment levels assumed for later years.

Sixth, for all years subsequent to 2023 the EPA applied the generation associated with the maximum annual capacity change from the historical data analysis. In 2024, this produces a building block 3 generation level of 332,869,933 megawatt-hours (aggregated across all three BSER regions); by 2030, that generation level is 706,030,112 megawatt-hours.

Seventh, to further evaluate the technical feasibility and cost-effectiveness of the building block 3 generation levels (aggregated across all three BSER regions), as well as to produce interconnection-specific levels of building block 3 generation from the national totals described in steps 5 and 6, the EPA conducted analysis using IPM of a scenario directing the power sector to achieve those RE generation levels. IPM modeling projections assess opportunities for RE deployment in an integrated framework across power, fuel, and emission markets. The modeling framework incorporates a host of constraints on the deployment of RE resources, including resource constraints such as resource quality, land use exclusions, terrain variability, distance to existing transmission, and population density; system constraints such as interregional transmission limits, partial reserve margin credit for intermittent RE installations, minimum turndown constraints for fossil fuel-fired EGUs, and short-term capital cost adders to reflect the potential added cost due to competition for scarce labor and materials; and technology constraints such as construction lead times and hourly generation profiles for non-dispatchable resources by season.[723] Additionally, the EPA assumes in this analysis that deployment of variable, non-dispatchable RE resources is limited to 20 percent of net energy for load by technology type and 30 percent of net energy for load in total at each of IPM's 64 U.S. sub-regions.[724] The 30 percent constraint applied to variable, non-dispatchable RE resources reflects levels commonly modeled in grid integration studies at the level of the interconnection. These studies have demonstrated that impacts to the grid in reaching levels as high as 30 percent of net energy for load are relatively minor.[725] For example, the Western Wind and Solar Study Phase 2 found cycling costs ranged from $0.14 to $0.67 per megawatt-hour of added wind and solar generation. These integration cost levels are not impactful in determining cost-effectiveness. As such, applying the 30 percent constraints at the IPM sub-region level is very conservative and provides a high degree of assurance that the RE capacity deployment pattern projected by the model would not incur significant grid integration costs.[726]

In addition to facilitating the EPA's assessment of the feasibility and cost of reaching the aggregate building block 3 generation levels across all three BSER regions, the IPM projections also provide the EPA with a basis for apportioning those generation levels to each interconnection. The EPA considered the projected regional location of the evaluated RE deployment in this analysis, which shows the

[722] Capacity values for utility-scale solar PV are expressed in terms of MW_{DC}. The assumed future capacity factor for this utility-scale solar PV includes a DC-to-AC conversion, enabling the generation totals to be combined across all RE technologies.

[723] Refer to GHG Mitigation Measures TSD for more detail on modeling methodology.

[724] Regions that have already exceeded these limits are held at historical percent of net energy for load.

[725] 2013 Wind Technologies Market Report. LBNL. August 2014. Available at *http://emp.lbl.gov/sites/all/files/2013_Wind_Technologies_Market_Report_Final3.pdf.*

Grid Integration and the Carrying Capacity of the U.S. Grid to Incorporate Variable Renewable Energy. NREL. Cochran et al., April 2015. *http://energy.gov/sites/prod/files/2015/04/f22/QER%20Analysis%20%20Grid%20Integration%20and%20the%20Carrying%20Capacity%20of%20the%20US%20Grid%20to%20Incorporate%20Variable%20Renewable%20Energy_1.pdf.*

The Western Wind and Solar Integration Study Phase 2. NREL. Lew et al., 2013. Available at *http://www.nrel.gov/docs/fy13osti/55588.pdf.* Refer to GHG Mitigation Measures TSD for further analysis.

[726] Refer to the GHG Mitigation Measures TSD for additional information on constraints related to deployment of non-dispatchable RE.

majority of such deployment occurring in the Eastern Interconnection. The GHG Mitigation Measures TSD describes in greater detail the process by which the EPA calculated the apportionment of building block 3 generation levels to each of the BSER regions, taking these modeling projections into account. Table 10 describes the annual building block 3 generation levels for each interconnection from 2022 through 2030.

TABLE 10—BUILDING BLOCK 3 GENERATION LEVELS (MWh).

Year	Eastern interconnection	Western interconnection	Texas interconnection
2022	*166,253,134*	*56,663,541*	*18,963,672*
2023	*181,542,775*	*60,956,363*	*28,177,431*
2024	*218,243,050*	*75,244,721*	*39,382,162*
2025	*254,943,325*	*89,533,078*	*50,586,893*
2026	*291,643,600*	*103,821,436*	*61,791,623*
2027	*328,343,875*	*118,109,793*	*72,996,354*
2028	*365,044,150*	*132,398,151*	*84,201,085*
2029	*401,744,425*	*146,686,508*	*95,405,816*
2030	*438,444,700*	*160,974,866*	*106,610,547*

Through the quantification methodology detailed above, the EPA has identified amounts of incremental RE generation that are reasonable, rather than the maximum amounts that could be achieved while preserving the cost-effectiveness of the building block. For example, assuming gradual improvement in RE technology capacity factors consistent with historical trends, expanding the portfolio of RE technologies that contribute to the building block 3 generation level, and applying the five-year maximum capacity change values to all years of the interim period are adjustments that would produce higher building block 3 generation levels and maintain the primacy of historical data in quantifying RE generation potential. External analysis and studies of RE penetration levels strongly support the technical feasibility and cost-reasonableness of RE deployment well in excess of the levels established by building block 3, as detailed in section V.E.7. By identifying reasonable rather than maximum achievable amounts, we are increasing the assurance that the identified amounts are achievable by the source category and providing greater flexibility to individual affected EGUs to choose among alternative measures for achieving compliance with the standards of performance established for them in their states' section 111(d) plans.

7. Feasibility of RE Deployment

The 2030 level of RE deployment and the rate of progress during the interim period in getting to that level are well supported by comments received, DOE and NREL analysis, and external studies evaluating the costs of and potential for RE penetration. The EPA has assessed the feasibility of RE in terms of deployment potential, system integration, reliability, backup capacity, transmission investments, and RE supply chains.

Historical RE deployment rates are a strong indication of the feasibility of the 2030 level of deployment and interim period pathway. The use of RE continues to grow rapidly in the U.S. In 2013, electricity generated from RE, including conventional hydropower, represented 12 percent of total U.S. electricity, up from 8 percent in 2005. In particular, there has been substantial growth in the wind and solar markets in the past decade. Since 2009, wind energy has tripled and solar has grown tenfold.

The expected future capacity installations in 2022–2030 needed to reach the 2030 level of incremental RE generation are consistent with historical deployment patterns. Forecasts by Cambridge Energy Research Associates (CERA) of 17 gigawatts in 2015 and historical deployment of 16 gigawatts in 2012 are significant. The average deployment of wind over the past five years was 6,200 megawatts per year; 2014 deployment of solar PV, both distributed and utility-scale, was 6,201 megawatts. This contribution from solar PV is consistent with the rapid reduction in costs that is currently being observed and is expected to continue.

Grid operators are reliably integrating large amounts of RE, including variable, non-dispatchable RE today. For example, Iowa and South Dakota produced more than 25 percent of their electricity from wind in 2013, with a total of nine states above 12 percent and 17 states at more than 5 percent. California served nearly 19 percent of total load in 2013 with RE resources, not including behind-the-meter distributed solar resources, and approximately 25 percent of total load with RE in 2014. On an instantaneous basis, California is regularly serving above 25 percent of load with RE resources, recently began seeing over 5,000 megawatt-hours of solar energy, and is on track for 33 percent of load with no serious reliability or grid integration issues. Germany exceeded 28 percent non-hydro RE as a percentage of total energy in first half of 2014. Other recent examples include: ERCOT met 40 percent of demand on March 31, 2014 with wind power; SPP met 33 percent of demand on April 6, 2013 with wind power; and, Xcel Energy Colorado met 60 percent of demand on May 2, 2013 with wind power. Operational and technical upgrades to the power system may be required to accommodate high levels of variable, non-dispatchable RE like wind and solar over longer time periods; however, the penetration levels cited above have been achieved without negative impacts to reliability due in large part to low-cost measures such as expanded operational flexibility and effective coordination with other regional markets.

RE can contribute to reliable system operation. The abundance and diversity of RE resources in the U.S. can support multiple combinations of RE in much higher penetrations. When California, the Midwest, PJM, New York, and New England experienced record winter demand and prices during the polar vortex, wind generation played a key role in maintaining system reliability.

Wind and solar PV are increasingly productive and capable of being accurately forecast, which improves grid reliability. Increasing capacity factors mean less variability and more generation. While the wind industry develops more projects at lower wind speed sites, wind turbine design changes are driving capacity factors higher among projects located in a given wind resource regime.[727] Average capacity factors have risen from the low 30 percent range to high 30 percent range and continue to improve. One key recent advancement is the increasing use of turbines designed for low to medium wind speed sites (with higher hub-heights and larger rotors, relative to nameplate capacity) at higher wind-speed sites with low turbulence.

New variable RE generators can provide more electrical power grid support services beyond just energy. Modern wind turbine power electronics allow turbines to provide voltage and reactive power control at all times. Wind plants meet a higher standard and far exceed the ability of conventional power plants to ''ride-through'' power system disturbances, which is essential for maintaining reliability when large conventional power plants break down. Xcel Energy sometimes uses its wind plants' exceedingly fast response to meet system need for frequency response and dispatchable resources. Utility-scale PV can incorporate control systems that enable solar PV to contribute to grid reliability and stability, such as voltage regulation, active power controls, ramp-rate controls, fault ride through, and frequency control. Solar generation is capable of providing many ancillary services that the grid needs but, like other generators, needs the proper market signals to trade energy generation for ancillary service provision.

The transmission network can connect distant high-quality RE to load centers and improve reliability by increasing system flexibility. Investments in transmission and distribution upgrades also enable improvements in system-wide environmental performance at lower cost.

The potential range of new transmission construction is within historical investment magnitudes. Under nearly all scenarios analyzed for the DOE's Quadrennial Energy Review, circuit-miles of transmission added through 2030 are roughly equal to those needed under the base case, and while those base case transmission needs are significant, they do not appear to exceed historical annual build rates. DOE's Wind Vision findings project 11.5 gigawatts of wind per year from 2021–2030. This deployment level would require 890 circuit miles per year of new transmission; 870 miles per year have been added on average between 1991 and 2013. 11.5 gigawatts per year is consistent with building block 3 deployment levels for wind capacity over the compliance period. DOE's SunShot scenario, which increases utility-scale PV to 180 gigawatts by 2030, required spending of $60 billion on transmission through 2050. On an average annual basis, this expenditure is within the historical range of annual transmission investments made by IOUs in recent decades.

Incremental grid infrastructure needs can be minimized by repurposing existing transmission resources. Transmission formerly used to deliver fossil-fired power to distant loads can—and is—being used to deliver REwithout new infrastructure. First Solar's Moapa project uses transmission built to deliver coal-fired power from Navajo to Los Angeles. NV Energy's retirement of Reid-Gardner will free up additional transmission capacity. The Milford wind projects in Utah already utilize transmission that was built to deliver coal power to Los Angeles.

Storage can be helpful but is not essential for the feasibility of RE deployment because there are many sources of flexibility on the grid. DOE's Wind Vision and many other studies have found an array of integration options (*e.g.,* large balancing areas, geographically dispersed RE, weather forecasting used in system operations, sub-hourly energy markets, access to neighboring markets) for RE beyond storage. Storage is a system resource, as its value for renewables is a small share of its total value.

Increasing regional coordination between balancing areas will increase operational flexibility. The Energy Imbalance Market (EIM) recently implemented by the California ISO and Pacificorp is a good example of the increased coordination that will be helpful in ensuring that resources across the West are being utilized in an efficient way.

Significant wind and solar supply chains have developed in the past decade to serve the fast-growing US RE market. For wind, domestic production capability would likely have to increase to accommodate projected builds under the CPP in the 2022–2030 time period; however, the global supply chain has expanded significantly to serve multiple markets and can augment production from the domestic supply chain, if necessary. At the start of 2014, the U.S. domestic supply chain could produce 10,000 blades (6.2 gigawatts) and 4300 towers (8 gigawatts) annually. It is not anticipated that expanded domestic manufacturing will be constrained by raw materials availability or manufacturing capability. For solar technologies, the global supply chain has a capacity that has significantly expanded over the past few years from 1.4 gigawatts per year in 2004 to 22.5 gigawatts per year in 2011. Current capacity exceeds these levels and is expected to grow. For PV systems, raw materials like tellurium and indium are at highest risk of supply shortage, but these materials are not used in the PV technologies currently being deployed at large-scale.

8. Cost of CO_2 Emission Reductions From RE Generation

The EPA believes that RE generation at the levels represented in building block 3 can be achieved at reasonable costs. In the EPA's modeling of the building block 3 generation level, the projected cost of achieving CO_2 reductions through this expansion of RE generation is $37 per ton on average from 2022 through 2030.[728] There are a number of reasons why the EPA believes that the cost of CO_2 emission reductions from RE generation will be lower than this analysis suggests. First, modeling constraints that restrict variable, non-dispatchable RE technologies to 30 percent of net energy for load at each of the 64 U.S. IPM regions is a conservative limit intended to eliminate significant grid integration costs at increased levels of RE penetration. In fact, many regions have already demonstrated levels of RE penetration that exceed the constraints, and in practice intermittency can be managed across larger regions than the 64. Consequently, the extent to which these regions could, in practice, achieve higher levels of RE deployment without facing substantial grid integration costs would lead to a lower-cost RE outcome than is estimated by this analysis. Second, there are multiple RE technologies not quantified under building block 3 that affected EGUs may use to demonstrate compliance (distributed generation technologies, offshore wind, etc.). Based on preliminary analysis from DOE and NREL, cost-effective opportunities for distributed generation alone could satisfy one-third to over one-half of the stringency associated with building block 3.[729] Third, as discussed in section V and VI of the preamble, the BSER reflects the degree of emission limitation achieved through the application of the building blocks in the

[727] LBNL, Wind Technologies Market Report 2013, August 2014, p. 43, Available at: *http://emp.lbl.gov/sites/all/files/2013_Wind_Technologies_Market_Report_Final3.pdf.*

[728] Refer to the GHG Mitigation Measures TSD for further analysis and IPM run results.

[729] See Section VIII.K. for a description of qualifying RE technologies for compliance.

least stringent region. By definition, in the other two regions the BSER is less stringent than the simple combination of the three building blocks, rendering a portion of the emission reduction potential quantified by the building blocks unnecessary to achieving the interim and final CO_2 emission performance rates. For example, the EPA has calculated that in excess of 160,000,000 megawatt-hours of building block 3 potential is not required to achieve the final CO_2 emission performance rates in 2030—and would be accessible to affected EGUs for compliance.[730] Therefore, it is reasonable to expect that it would cost less to achieve the component of building block 3 potential that is reflected in the calculation of the final CO_2 emission performance rates, as compared to the results of this analysis which assumed achievement of the entire quantified building block 3 potential. The EPA believes that these factors provide significant opportunities for achievement of the building block 3 generation levels at lower costs than estimated in this analysis.

VI. Subcategory-Specific CO_2 Emission Performance Rates

A. Overview

In this section, the EPA sets out subcategory-specific CO_2 emission performance rates to guide states in development of their state plans. The emission performance rates reflect the emission rates for two generating subcategories affected by the rule (fossil steam generation and gas-fired combustion turbines).[731] These final emission performance rates reflect the EPA's quantification of the BSER based on the three building blocks described in section V above. This procedure follows a similar logic to BSER quantification at proposal, but it keeps the emission performance rates separate for fossil steam and NGCC subcategories instead of immediately blending them together into a single value for all affected EGUs. Commenters noted that the proposed rule established guidelines that were based on the aggregation of units, and their reduction potential, in a state rather than providing technology-specific guidelines. While many commenters appreciated the flexibility this state-focused structure provided, some noted two concerns with this approach: (1) It would potentially create different incentives for the same generating technology class depending on the state in which that generator was located, and (2) it deviated from the EPA's previous interpretation of the 111(d) regulatory guidelines by not providing technology-specific standards of performance. In response to these comments and our further consideration, the final rule establishes subcategory-specific emission performance rates that are identical across units within a subcategory regardless of where a unit is located within the contiguous U.S. These subcategory-specific emission performance rates are then translated into state-specific goals which, as in the proposal, reflect the particular energy mix present in each state. That translation is presented in section VII.

These performance rates reflect the average emission rate requirement for each subcategory. Similar to the proposal, they are presented as adjusted average emission rates that reflect other generation components of BSER (*e.g.,* renewable) in addition to the fossil component. These performance rates must be achieved by 2030 and sustained thereafter. The interim performance rates apply over a 2022–2029 interim period and would be achieved on average through reasonable implementation of the best system of emission reduction (based on all three building blocks) described above. In other words, the interim performance rates are consistent with a reasonable deployment schedule of BSER technologies as they scale up to their full BSER potential by 2030. The performance rates are meant to reflect emission performance required across all affected EGUs when averaged together and inclusive of lower-emitting BSER components.

The performance rates are expressed in the form of adjusted[732] output-weighted-average CO_2 emission rates for affected EGUs. However, states are authorized to use a converted statewide rate-based or mass-based goal as discussed in the next section. The EPA has determined that the statewide rate-based and mass-based CO_2 goals are expressions of the emission performance rates equivalent to application of the emission performance rates to affected EGUs within a state.

The EPA is finalizing the performance rates in a manner consistent with the proposal, with appropriate adjustments based on comments. Stakeholders had the opportunity to demonstrate during the comment period that application of one or more of the building blocks would not be expected to produce the level of emission reduction quantified by the EPA because implementation of the building block at the levels envisioned by the EPA was technically infeasible, or because the costs of doing so were significantly higher than projected by the EPA. The EPA has considered all of this input in setting final performance rates.

The remainder of this section addresses two sets of topics. First, we discuss several issues related to the form of the performance rates. Second, we describe the performance rates, computation procedure, and adjustments made between proposal and final based on stakeholder feedback in the comment period.

Some of the topics addressed in this section are addressed in greater detail in supplemental documents available in the docket for this rulemaking, including the CO_2 Emission Performance Rate and Goal Computation TSD for CPP Final Rule and the Greenhouse Gas Mitigation Measures TSD. Specific topics addressed in the various TSDs are noted throughout the discussion below.

B. Emission Performance Rate Requirements

The EPA has developed a single performance rate requirement for existing fossil steam units in the contiguous U.S., and a single rate for existing gas turbines in the contiguous U.S., reflecting application of the BSER, based on all three building blocks described earlier, to pertinent data. The rates are intended to represent CO_2 emission rates achievable by 2030 after a 2022–2029 interim period on an output-weighted-average basis by all affected EGUs, with certain computation adjustments described below to reflect the potential to achieve mass emission reductions by avoiding fossil fuel-fired generation.

1. Final Emission Performance Rate Requirements

The emission performance rates are set forth in Table 11 below, followed by

[730] For additional discussion on how this concept impacts building block 3 generation levels, refer to the GHG Mitigation Measures TSD and the CO_2 Emission Performance Rate and Goal Computation TSD for Final CPP.

[731] The only natural gas fired EGUs currently considered affected units under the 111(d) applicability criteria are NGCC units capable of supplying more than 25 MW of electrical output to the grid. The data and rates for these units represent all emissions and MWh output associated with both the combustion turbines as well as all associated heat recovery steam generating units. The remainder of the section will use the term "NGCC" to collectively refer to these natural gas fired EGUs.

[732] As described below, the emission performance rates include adjustments to incorporate the potential effects of emission reduction measures that address power sector CO_2 emissions primarily by reducing the amount of electricity produced at a state's affected EGUs (associated with, for example, increasing the amount of new low- or zero-carbon generation rather than by reducing their CO_2 emission rates per unit of energy output produced).

a description of the computation methodology.

TABLE 11—EMISSION PERFORMANCE RATES

[Adjusted output-weighted-average pounds of CO_2 per net MWh from all affected fossil fuel-fired EGUs]

Subcategory	Interim rate	Final rate
Fossil Fuel-Fired Electric Steam Generating Units ...	1,534	1,305
Stationary Combustion Turbines	832	771

The emission performance rates are expressed as adjusted output-weighted-average emission rates for each subcategory. As discussed later in this section, the emission rate computation includes an adjustment designed to reflect mass emission reductions associated with lower-emitting BSER components. The adjustment is made by estimating the annual net generation associated with an achievable amount of qualifying incremental lower-carbon and zero-carbon generation and substituting those MWhs for the baseline electricity generation and CO_2 emissions from the higher-emitting affected EGUs. Under the final rule approach, regionally identified building block 3 potential generation replaces fossil steam and NGCC generation on a pro-rata basis corresponding to the baseline mix of fossil generation in each region.

2. Interim Emission Performance Rates

Some commenters suggested that the interim period starting in 2020 provided too little time for implementation of measures required to demonstrate compliance during the interim period. As discussed in section V.A.3.g of this preamble, the EPA has determined that an interim period beginning in 2022 provides sufficient time for states to undertake necessary planning exercises and for the implementation of measures towards achieving the performance rates. The EPA determined the interim rates in a manner similar to proposal, with an adaptation to address the revised timing of the interim compliance period (beginning in 2022 rather than in 2020 as proposed). They reflect the averaging of estimated emission performance rates for each year in the interim period (*i.e.,* 2022–2029).

The interim performance rates are less stringent than the final 2030 emission performance rates because the amount of emission reduction potential identified for the BSER increases over time, as explained in section V.

C. Form of the Emission Performance Rates

1. Rate-Based Guidelines

The interim and final emission performance rates for fossil steam and NGCC units are presented in the form of adjusted output-weighted-average CO_2 emission rates that the affected fossil fuel-fired units could achieve, through application of the measures comprising the BSER (or alternative control methods). Several aspects of this form of emission rate are worth noting at the outset: The use of emission rates expressed in terms of net rather than gross energy output; the use of output-weighted-average emission rates for all affected EGUs; the use of adjustments to accommodate incremental NGCC generation and RE measures that reduce CO_2 emissions by reducing the quantity of fossil fuel-fired generation and associated emissions; and the adjustability of the goals based on the severability of the underlying building blocks.

a. *Rationale for rate-based guidelines.* First, the EPA sets an emission rate requirement for each subcategory by identifying the technology-specific reductions available under the building blocks. We then give each state the choice to apply the emission performance rates directly to the affected EGUs within the state or provides the opportunity to use the statewide rate-based goal or the equivalent mass-based form translated from the emission performance rates for state plan purposes. The emission performance rates reflect the BSER, and the statewide rate-based goal and statewide mass-based goal are alternative metrics for realizing the emission performance rates at the aggregate affected fleet level for a state.

Stakeholders have expressed support for having the flexibility to choose from among the multiple options for crafting an implementation plan to realize the BSER. The EPA is providing emission performance rate-based guidelines that apply uniformly to technology subcategories nationwide, and the EPA is providing corresponding state emission rate goals and state mass goals to further enhance compliance flexibility for each state. This approach allows each state to adopt a plan that it considers optimal and is consistent with the state flexibility principle that is central to the EPA's development of this program.

b. *Net vs. gross MWh.*

The second aspect noted above concerns the expression of the goals in terms of net energy output [733]—that is, energy output encompassing net MWh of generation measured at the point of delivery to the transmission grid rather than gross MWh of generation measured at the EGU's generator. The difference between net and gross generation is the electricity used at a plant to operate auxiliary equipment such as fans, pumps, motors, and pollution control devices. Because improvements in the efficiency of these devices represent opportunities to reduce carbon intensity at existing affected EGUs that would not be captured in measurements of emissions per gross MWh, goals are expressed in terms of net generation. As noted by commenters, EGUs have familiarity and in some places already have in place equipment necessary to collect and report hourly net generation.[734]

c. *Output-weighted performance rates for all affected EGUs.* This final rule provides an expression of the BSER as subcategory-specific emission performance rates rather than the state goals provided at proposal. Whereas the proposal also estimated the BSER impact on fossil steam and NGCC emissions and generation, it went one step further by averaging these two technology rates into a single rate for each state. Under this final rule, the EPA is identifying the fossil steam rate and the NGCC rate separately instead of only presenting them in a blended fashion at the state level.[735] These two emission performance rates are the expression of the BSER for the final rule for affected EGUs located within the contiguous U.S.

The modification from a blended emission rate in the proposed rule to a subcategory-specific emission performance rate for affected EGU categories in the final rule was made in response to comments that technology

[733] As discussed below in Section VIII on state plans, we are similarly determining that states choosing a rate-based form of emission performance level for their plans should establish a requirement for affected EGUs to report hourly net energy output.

[734] Specifically, commenters noted that while net generation is not reported to the EPA under 40 CFR part 75, affected EGUs are generally required to report gross and net generation on a monthly basis to EIA through form 923 submittal.

[735] However, as discussed in the next section, in order to provide maximum flexibility to states, the EPA averages these two emission rates together for each state using their adjusted 2012 baseline generation share to arrive at a single statewide emission performance goal. The state has the option to comply with this statewide goal through a compliance pathway of its choice. This compliance pathway may or may not involve requiring its affected units to meet the emission performance rates.

subcategory-specific emission rates were more analogous to prior 111(d) efforts and more consistent with the statute. The EPA received significant comments suggesting a technology subcategory-specific rate is consistent with past section 111(d) regulations. However, many commenters also supported the flexibility provided to states through a state goal metric provided at proposal. Therefore, the EPA does provide alternative statewide rate-based and mass-based goals in the next section.

The EPA's main consideration has been to ensure that the expression of the BSER reflects opportunities to manage CO_2 emissions by shifting generation among different types of affected EGUs. Both the performance rates in this final rule and the state goals at proposal rely on the adjusted emission rate metric to reflect that potential shifting. Specifically, because CO_2 emission rates differ widely across the fleet of affected EGUs, and because transmission interconnections typically provide system operators with choices as to which EGU should be called upon to produce the next MWh of generation needed to meet demand, opportunities exist to manage utilization of high carbon-intensity EGUs based on the availability of less carbon-intensive generating capacity. For states and generators, this means that CO_2 emission reductions can be achieved by shifting generation from EGUs with higher CO_2 emission rates, such as coal-fired EGUs, to EGUs with lower CO_2 emission rates, such as NGCC units. Our analysis indicates that shifting generation among EGUs offers opportunities to achieve large amounts of CO_2 emission reductions at reasonable costs. The realization of these opportunities can be reflected in an emission rate established in the form of an output-weighted-average emission rate where the weighting reflects the varying levels of replacement generation technologies.

d. *Severability of building blocks.* Section V above discusses the severability of the three building blocks upon which the CO_2 emission performance rates are based. Because the building blocks can be implemented independently of one another and the emission performance rates reflect the sum of the emission reductions from all of the building blocks, if any of the building blocks is found to be an invalid basis for the ''best system of emission reduction . . . adequately demonstrated,'' the rates would be adjusted to reflect the emissions reductions from the remaining building blocks. The sole exception, as described above, is the application of building block 1 in isolation, which would not be implemented independently. The performance rates and statewide goals that would result from any combination of the building blocks could be computed using the formulas and data included in the CO_2 Emission Performance Rate and Goal Computation TSD for CPP Final Rule and its appendices using the methodology described below and elaborated on in that TSD.

D. Emission Performance Rate-Setting Equation and Computation Procedure

The methodology used to compute the performance rates is summarized on a step-by-step basis below in section 3. The methodology is described in more detail in the CO_2 Emission Performance Rate and Goal Computation TSD for CPP Final Rule, which includes a numerical example illustrating the full procedure. The quantification of the building blocks used in the computation procedure is discussed in Section V above and in the Greenhouse Gas Mitigation Measures TSD.

1. Inventory of Likely Affected EGUs

In order to calculate the subcategory-specific emission performance rates reflecting the BSER, the EPA first needed to develop a baseline inventory of likely affected EGUs in order to estimate the impact of the BSER. The EPA developed an inventory of likely affected units that were operating in 2012 or that began construction prior to January 8, 2014 and that appeared to meet the final rule's applicability criteria.[736] This inventory does not constitute a final applicability determination, but best reflects the EPA's estimate of units subject to the 111(d) applicability criteria as laid out in Section IV. The EPA identified a list of likely affected units at proposal comprised of approximately 3,000 EGUs. The agency took comment on this list and has made a number of updates to the inventory in response to those comments and in regards to applicability criteria changes resulting from comments. However, the inventory does not reflect a final applicability determination, and where a unit's status was unclear, the EPA generally treated the unit's status in a manner consistent with the proposal and publically available reported data.[737]

Since the final rule's applicability includes under construction units, the EPA also identified units that had not yet commenced operation by the 2012 baseline period, but that commenced construction before January 8, 2014. The EPA received significant comment on the proposal's sole use of the National Electric Energy Data System (NEEDS) to identify these under construction units. Commenters suggested that the EPA also utilize EIA and 2012 proposed unit-level files to help better identify under construction units. In some cases, NEEDS did not reflect units that had commenced construction. Therefore, the EPA updated its approach to identifying units that had commenced construction prior to January 8, 2014, but that had not commenced operation in 2012. In the final rule, the EPA uses EIA data, comments, as well as NEEDS data to identify these under construction units.[738] [739] [740]

These units that were operating by 2012 along with those that had not commenced operation by 2012 but had commenced construction by January 8, 2014, reflect the EPA baseline inventory of likely affected EGUs. The CO_2 Emission Performance Rate and Goal Computation TSD for CPP Final Rule explains the prime mover, capacity, and fuel criteria used to identify the likely affected EGUs.[741]

The EPA received significant comment that units that came online during the baseline year (*e.g.,* 2012) should be treated as under construction rather than operating units in 2012 for purposes of estimating baseline values, because their 2012 operation may be

[736] The EPA's responsibility is to determine the BSER for all affected EGUs. Some of these under construction units may not enter operation until 2015 or later, but they are likely affected units and therefore appropriate to reflect in the baseline and corresponding subcategory-specific emission performance rates and state goals.

[737] The EPA notes that in some cases, it may not yet be possible to determine the status of an EGU as affected or unaffected without additional data. There are potentially some units excluded or included in the baseline that will ultimately have a different status following an applicability determination. However, these cases are limited, and the effect of any collective changes to the affected fleet inventory will not yield a bias in the BSER computation at the regional level.

[738] The NEEDS database was also updated to reflect the latest data and commenter input on under construction units.

[739] For purposes of determining emission performance rates, the EPA classifies any unit that had begun construction prior to Jan. 8, 2014, but had not commenced operation by Dec. 31, 2011 as ''under construction''. Many of these ''under construction'' units have commenced operation at some point during 2012 or prior to signature of this final rule.

[740] ''Commence'' and ''construction'' are defined in 40 CFR 60.2.

[741] The baseline inventory relies on historical data and does not incorporate anticipated future retirements. Most commenters supported this treatment as they viewed those scheduled retirements (and corresponding emission reductions) as an alternative compliance flexibility.

misrepresentative of anticipated future-year operation due to partial year operation in 2012. The EPA has made an adjustment to flag these units as having commenced operation during 2012 and treat them as under construction units, consistent with commenters' suggestion; for BSER computational purposes, generation and emissions for these units are estimated based on a representative first full year of operation for that technology class.

2. Data Year

In the proposed rule, the EPA considered using a historical-year data set or a projected-year data set as a starting point for applying the technology assumptions identified under BSER. The EPA proposed using 2012 data as it was the most recent data year for which complete data were available when the EPA undertook analysis for the proposed rule and it reflected actual performance at the state level. The EPA took comment on alternative data sets. In particular, the EPA issued a NODA on October 30, 2014 (79 FR 64543) in which we provided 2010 and 2011 historic data for consideration.

The EPA received a significant number of comments supporting the use of historical data as the basis from which to quantify performance rates reflecting BSER. Some commenters supported the 2012 data year as the best reflection of the power fleet, and some suggested that the EPA use a different year or a historical average to control for data anomalies in 2012. Moreover, some commenters pointed out that using 2010, 2011, 2012 data, or an average of the three would not address their concerns about recent year anomalies in hydro generation due to high snow pack. Some commenters also suggested the EPA use a baseline including years prior to 2012, not to increase representativeness of the power sector, but as a means of recognizing early action.

In this final rule, the EPA is taking an approach to the baseline year where we still largely rely on reported 2012 data as the best and most recent available data representing the power sector from which to apply the BSER, but also including targeted baseline adjustments to address commenter concerns with 2012 data.[742] Below, we explain why—at the nationwide level—2012 data are preferable, more objective, and more accurate than a prior year, or an average of years, for informing the baseline. Then, we explain the adjustments that we are making to the 2012 data along with our rationale for such adjustments, in response to comments we received.

Some commenters supported the EPA's use of 2012 data to inform performance rates, and the EPA agrees that 2012 data with targeted adjustments, relative to other historical years, best reflects the power sector and best informs the performance rates that pertain to the BSER. The EPA believes that starting with 2012 data is more accurate and better informs the BSER than an earlier historical year or historical multi-year average for the following reasons:

(1) Of the historical data fully available at the time the proposal analysis began, 2012 was the most recent and best reflects the power fleet. Approximately 43 GW of new capacity came online in 2010 and 2011. In other words, there was 43 GW of capacity online as of 2012 that had not been in service at some point during the 2010–2011 period. Likewise, approximately 17 GW of capacity that were operable in 2010 and/or 2011 were retired prior to 2012.[743] Using state-level, prior year data, either on its own, or as part of a multi-year baseline, is not as representative of the current power fleet as the 2012 data, which better reflects significant changes in power sector infrastructure.

(2) A three-year baseline would not address some of the substantive concerns raised by commenters. Many commenters pointed out that using a three-year baseline would not address their critical concern about variation in the hydrological cycle due to snow pack (particularly in the Northwest), because the snow pack was significantly above average in both 2011 and 2012. The EPA agrees with commenters that we can better address their baseline data concerns regarding an average hydro year by identifying those states with a significant share of hydro generation and variation in that hydro generation, and making targeted adjustments to those states' affected fossil generation levels in order to reflect a more typical snow-pack year. This procedure is described in more detail below and in theTSDs.

(3) In addition to being, in the EPA's view, a less representative baseline of the existing power fleet, a multi-year baseline would also likely entail complexity when determining how to average together yearly fleet data while appropriately accounting for fleet changes occurring during those years. The 2012 baseline starting point maximizes the EPA's reliance on latest reported operating data and minimizes the need for fleet capacity adjustments. For instance, because of year-to-year fleet turnover, the averaging of multiple baseline years would require additional assumptions in regards to which generation to consider from a fleet that is changing in a given state or region (or even where units are switching fuel sources such as a coal-to-gas conversion).

(4) Due to the region-based approach to quantify building blocks and the BSER as subcategory-specific emission performance rates, variations in unit-level data do not significantly impact the calculation of emission performance rates. For instance, if one fossil unit is operating less in a given year due to an outage, another fossil unit in the same region is generally operating more. Therefore, at the regional level, fossil generation and emissions do not vary to the same degree that unit-level data varies. Moreover, the variation at the regional level that does exist in 2012 relative to previous years is not necessarily unrepresentative variation, but illustrates trends in the power sector infrastructure that are desirable to capture for purposes of determining a representative year from which further improvements in CO_2 emissions performance can be made. Because the EPA is moving from a state approach at proposal to a regional approach for calculating the expression of the BSER in this final rule, unit-level operational variation from year to year becomes even less relevant to the calculation of regional emission performance rates.

(5) Some commenters suggested the EPA use an earlier baseline year as a means of recognizing early action. They noted that an earlier baseline would reflect a higher-emitting fleet and therefore when the same level of building block MWhs are applied, they would result in a higher (*i.e.,* less stringent) state goal. The EPA disagrees with this view for several reasons. First, the objective of selecting a baseline to inform BSER is to have one that best reflects the power sector and consequently the best system of emission reductions of which the power fleet is capable. Using an earlier baseline that ''inflates'' the starting point would undermine this objective, not serve it. Second, the EPA disagrees with the premise of this comment—that the baseline would change and building block potentials would stay the same. For instance, building block 2 functions based on incremental generation potential (incremental generation = potential generation − baseline generation). This incremental value would increase if an earlier baseline period was used that had less existing NGCC generation.

(6) Some commenters pointed out that the EPA relied on multi-year historical data in allowance allocation in previous rulemakings (*e.g.,* CAIR and/or CSAPR allocations). However, that comparison is not relevant to the quantification of emission reduction potential under 111(d). In those previous instances, the EPA was considering typical unit-level behavior for allowance allocation purposes—not for determining the emission reduction requirements of the program. Those allowance allocation determinations were independent of and subsequent to the determination of emission reduction requirements in those rulemakings.

(7) The EPA received significant comment that 2012 was not a representative year for natural gas prices, and thus the EPA should use another year. The EPA disagrees with this comment, and does not view it as grounds for a change to the baseline period. While the EPA does recognize that Henry

[742] The EPA recognizes that more recent emissions and generation data have become available since 2012, but 2012 data constituted the most recent year for which full data was available at the time the EPA began its analysis for proposal.

[743] EIA Form 860, 2012.

Hub natural gas prices were lower in 2012 relative to previous years, this does not invalidate the suitability of the data year selection. The EPA's objective in selecting a baseline is to identify potential reductions when BSER technologies are applied; year-to-year variation in market prices for natural gas does not frustrate this effort. For instance, a region may have generated only 5 MWh of NGCC generation in 2011 when gas prices were higher, and 10 MWh of NGCC generation in 2012 when gas prices dropped. However, this does not change the outcome of the quantification of the BSER, because the building block is based on the emission reduction *potential* of the fleet. That potential (*e.g.,* a fuller realization of the existing NGCC generation potential equivalent to 15 MWh) does not change regardless of the year used for baseline NGCC generation. Therefore, a different data year may change a baseline data point, but it would not change the total potential NGCC generation for quantifying the emission performance rates in these circumstances.

In summary, the EPA believes that continuing to rely on 2012 data while incorporating select data adjustments as detailed below is not only a reasonable choice and adequately supported, but a more reliable and preferable starting point for determining the BSER requirements.

3. Adjustments That the EPA Made to the 2012 Data

The EPA made corrections to unit-level 2012 data based on commenter feedback. In addition, we also made some adjustments to 2012 data, not to address a correction, but to address a concern about the representativeness of the data. Although the EPA determined that the 2012 data year better informed its BSER determination than a preceding year or a multi-year average, commenters did identify some limitations that we are addressing through targeted adjustments. These are discussed below:

(1) Adjustments to state-level data to account for annual variation in the hydrologic cycle as it relates to fossil generation.

Hydropower plays a unique role in a handful of states in that (1) it is a significant portion of their generation portfolio, (2) it varies on an annual basis, and (3) 2012 was an outlier year for snow-pack (meaning hydropower was above and fossil generation was below its historical average).The EPA notes that these three conditions are not present in other weather-based RE technologies like solar or wind.[744] Therefore, no similar adjustment was needed to account for weather patterns with these technologies.

Unlike market conditions (*e.g.,* changes in natural gas prices) that may produce different generation profiles year-to-year but that do not change the overall generating potential of the state's power fleet, variation in the hydrologic cycle does fundamentally change the generating potential of the state's power fleet in hydro-intensive states as they no longer have the same generating potential in an average year as they had in a ''high hydro'' year. The CO_2 Emission Performance Rate and Goal Computation TSD for CPP Final Rule provides analysis and explains the adjustment that the EPA made to the state-level 2012 data for Idaho, Maine, Montana, Oregon, South Dakota, and Washington to better reflect fossil generation levels when hydro generation performed at its average level as observed over a 1990–2012 timeframe. The EPA agrees with commenters that using a 2010–2012 baseline would not address the concern as 2011 was also an outlier year relative to historical snow-pack and hydro generation.

(2) Extended unit outages due to maintenance.

Generally, because of the regional-level approach to calculate performance rates, the EPA does not believe that unit-level variations in operation influence the subcategory-specific performance rates reflecting BSER. For instance, as some units ramp down, and others ramp up to replace their load at the regional level, total fossil generation changes little due to these fossil-for-fossil substitutions. Unit-level variation does not inherently entail region-wide variation.

However, the EPA did receive comment that in limited cases, this could have a substantial impact on an individual state if it chooses to use a rate-based or mass-based statewide goal. Even though the EPA is calculating subcategory-specific performance rates that it believes are not affected by this type of unit-level variation, it still evaluated the possible impacts it may have when converting to state goals in the next section. The EPA examined units nationwide with 2012 outages to determine where an individual unit-level outage might yield a significant difference in state goal computation. When applying this test to all of the units informing the computation of the BSER, emission performance rates, and statewide goals, the EPA determined that the only unit with a 2012 outage that (1) decreased its output relative to preceding and subsequent years by 75 percent or more (signifying an outage), and (2) could potentially impact the state's goal as it constituted more than 10 percent of the state's generation was the Sherburne County Unit 3 in Minnesota. The EPA therefore adjusted this state's baseline coal steam generation upwards to reflect a more representative year for the state in which this 900 MW unit operates.

(3) Many commenters also noted that because the EPA uses annual data, 2012 was not representative for units coming online part way through the year. The EPA relies on annual data, so if a unit is underrepresented in a certain part of the year because it is not yet online, then another unit is likely over-represented as it is operating more than it otherwise would when the second unit commences operation. Therefore, the resulting state-level and regional-level aggregate annual generation level used in determining the BSER may be considered to be representative and there is not necessarily a need for any adjustment.

However, the EPA recognizes that the over-represented and under-represented units do not necessarily fall within the same state, and therefore this potential difference in the state location of the affected units could have an impact when estimating appropriate statewide goals. To address this comment, the EPA adjusted the 2012 generation data for fossil units coming online during 2012 to a more representative annual operating level for that type of unit reflecting its incremental impact on generation and emissions. This effectively resulted in increased baseline emissions and generation assumed for those units beyond their reported partial-year operations in 2012. Conceptually, the assumption of full-year operation at units that came online partway through 2012 could pair with an assumed reduction in the operation of other units somewhere in the same region. However, the EPA made no corresponding deduction to represent this likely decreased utilization at other affected units because it was impossible to project the state location of such units with certainty and the assumed utilization level was meant to reflect the incremental impact on the baseline. As a result, this data adjustment increases the total generation and emissions for units reporting in the 2012 baseline beyond the 2012 reported levels.

Additionally, as done in proposal, the EPA continued to identify under construction units that did not begin operation in 2012, but had commenced construction prior to January 8, 2014 and would commence operation sometime after 2012. As described in the next section, the EPA estimated baseline generation and emissions for these units as they had no 2012 reported data.

In summary, this final rule continues to rely on the latest reported 2012 data as the foundation for quantifying the BSER. However, the EPA has made limited adjustments, in addition to corrections identified by commenters, to the 2012 data to address some of the relevant concerns raised by commenters. Therefore, the baseline is informed by 2012 data, but not limited to 2012 data.[745]

4. Equations

In this section we describe how we develop the equations used to determine the emission performance rates for fossil steam and NGCC units that express and implement BSER. More detailed

[744] While solar and wind generation may vary on an hourly or daily basis, their annual generation profiles are subject to notably less variation compared to hydropower. The EPA's calculation of the BSER relies on annual generation data, not on hourly or daily generation data.

[745] Updated unit-level data reflecting corrections identified by commenters to the underlying 2012 file are provided in Appendix 1 of the CO_2 Emission Performance Rate and Goal Computation TSD for CPP Final Rule. The adjustments made to the aggregate data to address representativeness concerns are provided in Appendix 3.

information regarding rate computation, including example calculations, can be found in the CO_2 Emission Performance Rate and Goal Computation TSD for CPP Final Rule, which is available in the docket for this action. Here we first present the general principles we follow when developing equations to express the BSER; then, we summarize the steps taken to assemble baseline data to reflect 2012 baseline emissions and generation, and apply the building blocks that constitute the BSER to derive performance rates that will be used by states to implement BSER. Section VII then explains how these nationwide performance rates are reconstituted into a statewide goal metric similar to the proposal in order to allow a state (at its discretion) to use a statewide goal as a mechanism for demonstrating compliance at the aggregate state level in a state plan, as an alternative to applying the emission performance rates to its affected EGUs directly.

When developing equations to implement BSER, we adhere to a number of basic principles. First, we ensure that the equations are consistent with the BSER itself, and in particular, reflect the redistribution of generation among fossil steam, NGCC and renewables embodied in building blocks 2 and 3. In doing this, we account for the interactions between building blocks in a way that is consistent with the assessment of incremental building block generation potential and the compliance framework for Emission Reduction Credits (ERCs). In particular, we must ensure that each increment of building block 3 emission reduction potential is applied to either fossil steam or NGCC units but not both. The equations we develop must also take account of the dual status of existing NGCC units, which are simultaneously affected units and provide generation that is an element of the BSER itself.

In addition, we are applying the BSER, as we have done in calculating other section 111(d) standards, to a defined population of existing affected sources, represented in this case by the generation of the source category in the 2012 adjusted baseline. This provides an empirical historical baseline against which we define the performance rates and their state goal equivalents. In doing so, we must account for any offsetting increases in emissions that result from applying the BSER control measures, as we have done in setting other standards. For example, when determining BSER for particulate matter control, a number of pollution control devices (such as sorbent injection technologies) themselves create particulate matter. If the particulate matter created by these control devices were not appropriately accounted for when developing the standard intended to address the primary emissions of particulate, this could create an unreasonably stringent PM standard. In the current context, this means recognizing that increasing NGCC capacity utilization in accordance with building block 2 both offsets higher emitting steam generation and increases emissions at the NGCC units themselves, which are also affected entities that must demonstrate compliance with the BSER. Thus, it is essential that we apply the building blocks in a way that avoids creating a level of stringency in the performance standards for affected EGUs that goes beyond what we have determined to be the BSER—while at the same time ensuring that equations apply the building blocks to generate performance standards that represent the full application of the BSER to the affected EGUs.

Under section 111, the EPA adopts emission performance standards that are based on the BSER. The emission performance rates reflect our recognition of the value of giving sources the flexibility to adopt equivalent emissions reduction strategies and measures that for them may be preferable (in a specific circumstance) to the technologies and measures that we define as the BSER. An important function of the emission performance rates representing the BSER is to provide the flexibility needed to allow alternative compliance options, including the development of new technologies or the deployment of effective technologies outside of the BSER technologies. In the guidelines we issued under section 111(d) for landfill gas, for example, we adopted the primary standard based on flaring of any captured landfill gas, but we also developed equations that led to an expression of the BSER that allowed for the alternative of capturing the gas and combusting it in an electrical generating unit.

Finally, in deriving the emission performance rates, there are a number of considerations we took into account. First, it is important that the baseline from which the rates are derived be transparent and based on observable, historical data. Second, the emission performance rates must reflect the emission reductions achievable through the best system of emission reduction. Because the BSER includes shifting of emissions from higher-emitting to lower-emitting sources, state compliance frameworks will likely involve a combination of physical measures at the plant (where either rate or generation may be reduced) and some form of credit for lower-emitting generation (or demand side measures) outside of the plant. In this context, the emission performance rates must provide appropriate incentives for affected entities to achieve the emission reductions encompassed in the BSER, including through state plans that provide crediting for lower-emitting generation. Third, and as set forth below, we must account for the EPA's determination that pro rata implementation of building block 3 is the best reflection of the potential for RE to displace both fossil steam and NGCC, and the dual role of NGCC units as both affected sources and a BSER compliance technology.

This set of considerations was central to the development of the BSER equations that the EPA describes next. They were particularly important for steps five through seven below which address building blocks 2 and 3, building blocks that have both significant overlap with each other and which impact steam and NGCC units in an integrated way.

Step-by-Step Discussion of Equations

Step one (compilation of baseline data). On a unit-level basis, the EPA obtained total annual quantities of CO_2 emissions, net generation (MWh), and capacity (MW) from reported 2012 data for likely affected EGUs that had commenced operation prior to 2012.[746] The EPA made changes to the historical unit-level data based on comments received at proposal. For each state and region, the agency aggregated the 2012 operating data for all coal-fired steam EGUs as one group, all oil- and gas-fired steam EGUs as a second group, and all NGCC units as a third group. The EPA adjusted these state values upwards in

[746] EGUs whose capacity or fossil fuel combustion were insufficient to qualify them as likely affected EGUs were not included in the subcategory-specific rate and goal computations. Most simple cycle combustion turbines (CTs) were excluded on this basis at proposal, and all simple cycle CTs were excluded at final reflecting changes to the applicability language. IGCC's were designated as ''other'' generation at proposal, but they are grouped with coal units for purposes the final rule category-specific rates. Useful thermal output (UTO) was also translated to a MWh equivalent and included in state goals at proposal, resulting in more stringent rates for states with more cogeneration sources, but UTO is not included in this final rule emission performance rate or state goal calculations as a result of comments regarding potentially adverse impacts on cogeneration units and uncertainty of thermal load outputs. As described in the state plan section of the preamble, units may still quantify and convert UTO (*i.e.,* taking credit for waste heat capture) when demonstrating compliance. See the applicability criteria described in Section IV.D above.

a limited number of instances to reflect the hydropower and unit outage concerns raised in comments and described above. As discussed above, the EPA first only aggregated the reported data for units that commenced operation prior to 2012. For those likely affected units that commenced operation during 2012, the EPA treated that capacity consistent with its framework for under construction affected units, which were added next. This was done in response to comments recognizing the fact that the year during which a unit commences operation may not have been representative of its potential generation and emissions.

For the under construction units (*i.e.,* those under construction prior to January 8, 2014 but which had not commenced operation by December 31, 2011), the EPA estimated their incremental impact on the baseline generation and emissions using their capacity. The EPA assumed a 55 percent capacity factor for under construction NGCC units and a 60 percent capacity factor for under construction fossil steam units, which are consistent with the values and methodology the EPA proposed for under construction units.[747] These values are informed by the 2012 capacity factors for other units in these technology classes that recently commenced operation.[748] Using these capacity factors along with the capacity for the units, the EPA estimated an annual baseline generation value for these units. The agency then estimated annual baseline CO_2 emissions for these under construction units using the average emission rate of generating units of the same technology in the state where the under construction unit is located. Where no generators of the same technology existed in a given state, the EPA used the national baseline average for that technology. This is similar to the adjustment made at proposal for under construction units, with the main difference being units that commenced operation in 2012 are now also treated as under construction for baseline data purposes in the final rule.

The estimated emissions and generation for under construction units were added to the 2012 reported emissions and generation data for the affected units that had already commenced operation prior to 2012 to derive an adjusted historical baseline total for each state that was reflective of all likely affected 111(d) sources.[749]

Step two (aggregation to the regional level). The EPA took comment on applying building blocks at the regional level, and received significant comment supporting such an approach. Therefore, whereas the proposal aggregated the baseline data to the state level, the final rule further aggregated it to the regional level prior to building block application. The regions reflect the Eastern, Western, and Texas Interconnections. The shift to a regional framework was based on comments suggesting that the EPA would better capture the interstate impacts of the building blocks and reflect the interconnected nature of the electric grid under a regional structure. The basis for the regions is defined and discussed in Section V.A.3.

Step three (identification of source category baseline emission rates). As discussed in the beginning of this section, the EPA took a technology-specific approach to quantifying guidelines. Therefore, whereas the proposal first averaged the fossil steam rate and NGCC rate together before applying the building blocks and defining state goals, the final rule applied the building blocks at the regional level to give a separate fossil steam rate and NGCC rate for each region. The starting point for calculating the subcategory-specific emission performance rates was the baseline regional emission rates for both fossil steam and NGCC in the year 2012 with the modifications discussed above.

Step four (application of building block 1). The baseline CO_2 emissions amount for the coal-fired steam EGU fleet in each region was reduced by 2.1, 2.3, and 4.3 percent in the Western, Texas, and Eastern Interconnections respectively, while the coal generation level was held constant, reflecting the EPA's assessment of the average opportunities in each region to reduce CO_2 emission rates across the existing fleet of coal-fired steam EGUs through heat rate improvements that are technically achievable at a reasonable cost. The EPA then averaged together the region's baseline oil- and natural gas-fired steam rate with its building block 1 adjusted coal steam rate to get a fossil steam rate post-building block 1.[750] [751]

Step five (application of building block 3). At proposal, the EPA incorporated incremental RE MWhs (where incremental means the amount above the adjusted 2012 baseline) by adding them to the denominator of the emission rate goal. In response to comments on this approach, the EPA issued a NODA discussing an alternative methodology of incorporating building block 3 in a manner more analogous to building block 2 treatment, where the incremental MWhs identified for the building block replace baseline fossil MWhs on a one-to-one basis. The EPA is adopting this replacement methodology for building block 3 in the final rule consistent with comments noting that such a computational procedure better reflects the reduction potential of that building block.

Under this methodology, all of building block 2 incremental NGCC potential and part of building block 3 incremental RE potential were ultimately applied to replace higher-emitting fossil steam generation and emissions, while the remaining building block 3 potential was applied to replace NGCC generation and emissions. Commenters noted that under this approach building block 3 should be applied first, or the EPA would understate the potential of building block 2 by subtracting out some NGCC generation after the 75 percent utilization level of NGCC had been applied to replace fossil steam. The EPA agrees and calculated the building block 3 impacts first in developing the emission performance rates.

To implement this, first, building block 3 replacement potential was identified for each region to arrive at a total amount of incremental zero-

[747] The EPA notes that we did not identify any under construction coal units at proposal, but we are using a methodology in this final rule for newly categorized under construction coal units similar to our under construction assessment of NGCC at proposal.

[748] The EPA received comment on the assumed 55 percent capacity factor for under construction NGCC EGUs. Some comments suggested the value was too large of an estimation for incremental generation as some of that 55 percent utilization would have a replacement impact on 2012 operating generation. Others suggested it should be larger as a particular planned under construction unit was anticipated to have a higher utilization rate. The EPA reviewed operating patterns of EGUs that came online, and determined a 55 percent and 60 percent capacity factor assumption for under construction NGCC and coal EGUs respectively are a reasonable estimate for informing the incremental emissions and generation from under construction units. It recognizes that some of these units may indeed operate at a higher utilization level, but also recognizes that some of the generation may have a replacement effect instead of an incremental one.

[749] The EPA received some comments suggesting that under construction units should not be included in the quantification of BSER and/or rate calculations, and other comments supporting their inclusion. The EPA determined that including it was consistent with our responsibility under the 111(d) statute to define a Best System of Emission Reduction for existing units.

[750] Building block 1 analysis acknowledges some variation in heat rate improvement potential at different units. The implementation of this building block reflects a heat rate improvement on average across a region's coal fleet, not necessarily a heat rate improvement at every unit.

[751] Baseline OG steam emissions are added to adjusted coal emissions and divided by baseline OG steam generation and baseline coal generation.

emitting generation hours available to replace fossil generation in the region. Because renewable generation can replace both fossil steam and NGCC on the grid, the EPA determined that it was appropriate to apply these incremental zero-emitting generation hours to replace generation and associated emissions from each of the fossil steam and NGCC fleets in the region on a pro-rata basis in the following manner.[752] The EPA determined the percent of fossil steam generation and the percent of NGCC generation of total affected fossil generation in each region's baseline. We then assigned those percentages of the incremental zero-emitting MWhs to each of those technology source categories.[753] The incremental zero-emitting generation assigned to each technology replaced the same amount of fossil generation from that technology's baseline value.

Step six (application of building block 2). If the remaining generation level for the NGCC fleet in a region, taking into account the previous step's replacement of NGCC generation, was less than 75 percent of the fleet's potential summertime generating capacity (the potential capacity factor the EPA determined to represent the BSER), then the NGCC generation in the region was assumed to increase to levels equal to the lesser of (1) its potential at a 75 percent capacity factor[754] or (2) a generation level above which there is no longer fossil steam generation remaining within the same region to replace. In other words, the regional NGCC capacity factor was only assumed to reach 75 percent if there was sufficient higher-emitting fossil steam generation that it could replace after step five. The increase in NGCC generation at this step compared to the post-building block 3 level was matched by an equal decrease in fossil steam generation reflecting the 1 for 1 MWh hour replacement. At this point, the generation for both steam and NGCC reflect the final distribution of generation between the subcategories after application of the building blocks. But the emission performance rates must account for CO_2 emissions and generation from incremental gas and renewable generation that comprise building blocks 2 and 3, to reflect and enable the emission reductions achievable under the best system of emission reduction, and ensure that the shared implementation of the BSER by steam and NGCC generation is reflected in the rates.

Step seven (accounting for and facilitating the emission reductions achievable through the implementation of the best system of emission reduction).

This step quantifies the aggregate emission changes associated with the emission rate improvement and generation replacement patterns described in steps four, five, and six to arrive at an adjusted fossil steam emission rate and an adjusted NGCC emission rate for each region that will, as discussed above, (1) enable the implementation of all three building blocks, (2) be based on observable, concrete baselines, and (3) reflect the BSER.

First, in developing the emission performance rates, the EPA had to answer the question of how to reflect the building blocks in the equations defining the rates in a manner that would enable the generation shifts that are essential components of the BSER. In the case of building block 3, the EPA accomplished this by incorporating the pro rata share of incremental (above baseline) zero emitting generation into the emission rates for each group of affected EGUs, thus ensuring that these EGUs would have to include a corresponding amount of zero-emitting generation in their compliance calculations, either through the acquisition of credits or through some other mechanism as determined by their state in its implementation plan.

For building block 2, a similar mechanism is needed. Accordingly, a portion of the NGCC generation and emissions used to replace fossil steam must be averaged into the steam rate, analogous to what was done with building block 3. The EPA considered two approaches to define the quantity of NGCC generation and emissions to be averaged into the steam rate: (1) Incremental NGCC generation after the implementation of building block 3 and (2) incremental NGCC generation from baseline levels. For the reasons below, the EPA has determined that the second approach better reflects the considerations discussed above.

As discussed above, it is beneficial that the baseline from which emission performance rates are derived be transparent and based on observable historical data. The first approach, however, depends on the level of incremental NGCC generation relative to what is available after the implementation of building block 3. This level of NGCC generation (obtained after replacing baseline levels of generation with NGCC's pro rata share of incremental RE generation) only exists as an intermediate step in the BSER calculation. It is not based on an observable or concrete level of generation.

In Section VIII we discuss methods for creating ERCs for implementing shifting of generation from steam to NGCC, and this discussion illustrates the value of relying on an observable and concrete baseline. In that section we suggest that incentivizing and facilitating the purchase of ERCs as a compliance option for steam units could be implemented through the use of a factor that creates a fraction of an allowable credit for each hour that an NGCC operates. This factor is derived from the incremental generation of NGCC post-building block 2, relative to the baseline. While a different factor could be derived from the hypothetical intermediate level resulting from the pro rata application of zero emitting generation to NGCC in building block 3 (by transferring the full amount of NGCC emissions and generation replacing steam generation in building block 2), the EPA believes that grounding baselines in historical data (such as those used to derive the 2012 baseline) is both more transparent and easier to understand in a way that is more useful to states and utilities, in contrast to the practical challenges of relying on a calculated level that corresponds to an interim step within the emission performance rate calculation. As long as the crediting framework for creating ERCs is consistent with the amount of gas emissions and generation that is transferred to the coal rate, either the chosen option or the option of transferring the entire quantity of gas emissions and generation that occurred in step six to the coal rate would provide an incentive for the power market to implement the shift in generation from coal to gas.[755]

[752] The EPA took comment on a pro-rata or an intensity-based replacement approach. In this final rule, the EPA agrees with commenters that a pro-rata approach is a better reflection of the BSER. Incremental RE generation has, and is likely to continue, to replace both steam and gas turbine generation and the BSER captures this through a pro-rata distribution of identified building block 3 potential.

[753] For example, if 100 MWh of incremental zero emitting generation is available in a given region and that region had 70 percent of its affected fossil generation coming from fossil steam units in the baseline and 30 percent from NGCC units—then 70 MWhs of the incremental zero-emitting generation are applied to baseline fossil steam generation and 30 MWhs are applied to baseline NGCC generation.

[754] In early years, will be less than 75 percent due to building block 2 gradual deployment.

[755] The EPA recognizes that real world market dynamics will necessarily differ from the BSER assumptions, and has designed the emission guidelines to provide flexibility beyond the emission reduction opportunities identified in the BSER. The essential criteria, however, are that the emission rates and crediting framework are consistent with the BSER and provide the incentives needed to facilitate the emission

Also as discussed above, it is important that the compliance equations reflect the BSER pro rata allocation of RE to fossil steam and NGCC generation. The first approach to define the quantity of NGCC generation and emission to be averaged into the steam rate would require the steam rate to take into account the total additional NGCC generation that results from the application of building block 3 before building block 2 has been applied. This approach would reflect in the compliance rate for steam units a greater share of the implementation of building block 3. Ensuring that emission performance rates for both steam and gas units reflect the emission reduction potential of building block 3 is integral to the building block 3 methodology and also recognizes that application of building block 3 on a pro-rata basis was intended to achieve emission reductions from both NGCC and fossil steam commensurate with their emissions reduction opportunities.

If the EPA were to use the increment of NGCC emissions and generation derived at the intermediary step after the application of building block 3, rather than the increment relative to the 2012 baseline, the effect would be to largely assign to fossil steam the building block 3 generation shift apportioned to NGCC. That, in turn, would have undermined the fact that building block 3 was determined to be a BSER measure applicable to the entire source category, comprising NGCC as well as fossil steam, and would have conflicted with the preceding steps we are taking to develop the equations. Instead, by using only the incremental NGCC generation relative to the baseline, the EPA has ensured that the logic behind the pro rata displacement of fossil generation by RE generation is reflected in the emission rates. Having established the appropriate way to measure the amount of incremental gas generation placed in the fossil steam rate, the EPA is able to calculate the subcategory-specific emission performance rates. For the numerator of the fossil steam rate, the EPA multiplied the remaining fossil steam generation (post-step six) by the fossil steam rate reflecting the heat rate improvement from building block 1 (step four). We then added in the emissions associated with the incremental NGCC generation from step six by multiplying the incremental NGCC generation as discussed above (difference between the baseline NGCC generation level and post-step six NGCC generation) by the baseline NGCC rate for that region.[756] This constitutes the numerator of the fossil steam emission rate.

For the fossil steam denominator, the EPA added the remaining fossil steam generation (post-step six), the incremental NGCC generation defined above, and the amount of zero emitting building block 3 MWhs apportioned to fossil steam generation in the region (step five). Dividing the fossil steam numerator described above by this fossil steam denominator resulted in a regional adjusted fossil steam rate reflecting the three building blocks.

For the NGCC performance rate, the EPA calculated a numerator in a similar manner. First, we took the remaining NGCC generation (post step six) and multiplied it by the regional baseline NGCC rate to calculate the total emissions in the numerator. For the denominator, the EPA added the remaining NGCC generation (post step six) to the amount of zero-emitting building block 3 generation assigned to that technology in step five. Dividing the emissions by this total generation value (inclusive of the RE generation apportioned to NGCC) provided a regional adjusted NGCC rate.[757]

Step eight (determining the nationwide subcategory-specific emission performance rate).

Following step seven, we evaluated the resulting adjusted fossil steam rates and NGCC rates for each region and identified the highest (least stringent) emission rate among the three regions for each technology category. This becomes the nationwide emission performance rate for that technology class. This ensures that the same rates are applied to facilities in each region and that these rates are achievable by facilities in all three regions.

Finally, the EPA repeated steps four through eight for each year 2022–2030.[758] The resulting annual rates vary because the amount of building block 2 and 3 potential in each year varies. The rates for years 2022–2029 were averaged together to calculate an interim rate, and the 2030 value becomes the final emission performance rate for that year forward. As described in the corresponding TSD, the EPA rounded the interim and final subcategory-specific emission performance rates up to the nearest integer to ensure that they did not slightly overstate BSER potential through use of conventional rounding. Unless otherwise stated, conventional rounding is used elsewhere during the calculation process.

It bears emphasis that the procedure described above was used only to determine emission performance rates, and the particular data inputs used in the procedure are not intended to represent specific requirements that would apply to any individual EGU or to the collection of EGUs in any state. The specific requirements applicable to individual EGUs, to the EGUs in a given state collectively, or to other affected entities in the state, would be based on the emission standards established through that state's plan. The details of how states could demonstrate compliance with the emission performance rates or statewide goals through different state plan approaches that recognize emission reductions achieved through all the building blocks are discussed further in section VIII on state plans.

Finally, the procedures and assumptions in the equation to calculate emission performance rates are not intended to reflect a compliance scenario in a future year, but rather reflect a representative year in which the building blocks are applied. The power sector fleet will continue to turn over, and in some cases has already experienced turnover beyond the baseline period. However, while the system's fleet may change, the EPA believes this turnover will only further promote the feasibility of the emission performance rates. Fleet turnover has trended towards, and is expected to continue to trend towards, lower-emitting generation sources that will make reductions more readily available.

---

reduction measures reflected in the BSER and together produce an achievable compliance framework for sources.

[756] See CO_2 Emission Performance Rate and Goal Computation TSD for CPP Final Rule for an illustration of this step. The EPA defined the ''incremental NGCC generation'' in this step in a manner consistent with its measurement and use described in section VIII of this preamble.

[757] See CO_2 Emission Performance Rate and Goal Computation TSD for CPP Final Rule for an illustration of this step. We note that the entire NGCC generation level (inclusive of the amount assigned to the fossil steam rate) expected post building block application is included in the NGCC rate calculation. Including the entire NGCC generation in the NGCC rate recognizes the simultaneous compliance responsibility of affected NGCC units while the fossil steam rate recognizes its mitigation potential through incorporation of the incremental NGCC generation component. Failing to do so would result in a NGCC rate lower than that expected after full implementation of the building blocks and create a compliance inconsistency when reporting all generation.

[758] At proposal, the EPA repeated this step over a 10 year period. The building blocks and corresponding BSER emission rates increased for ten consecutive years (2020–2029) in the EPA's rate calculation. In this final rule, the EPA has maintained the same 2030 compliance period for final rates but adjusted the start date to 2022 based on comments. Therefore, the deployment of building blocks is spread over a nine year period (2022–2030) instead of the proposed 10 year period.

VII. State-Specific CO_2 Goals

A. Overview

In section VI of this preamble, the EPA provides the methodology for computing subcategory-specific CO_2 emission performance rates, based on the BSER. The subcategory-specific CO_2 emission performance rates are the quantitative expression of the BSER as determined by the EPA. In this section, we provide state rate-based goals and mass-based goals that can be used in the alternative, by states, as an equivalent quantitative expression of the BSER in establishing standards of performance for affected EGUs in state plans. In this section, the EPA also describes reasons for providing state-specific rate-based goals and mass-based goals equivalent to the emission performance rates, supported by the many requests from commenters for the provision of these alternative expressions of the BSER established by the EPA. We further ensure this equivalence, and therefore reflection of the BSER, by requiring that rate-based state goals and mass-based state goals fully implement the BSER, including by ensuring that affected EGUs operating under mass-based emission standards are not incented by dint of the mass-emissions constraint to shift generation to unaffected fossil fuel-fired sources to an extent that deviates from, or negates, the implementation of the BSER.

The EPA is reconstituting the emission performance rates discussed in section VI into statewide CO_2 emission performance goals for each state for the purpose of facilitating states' development of state plans encompassing maximum flexibilities in implementing the BSER. This state-specific goal is not a compliance requirement, but rather an alternative yet equivalent expression of the BSER that the state may choose to use to establish emission standards for its affected EGUs. The state goal is the equivalent of the technology-specific CO_2 emission performance rates and represents the equivalent of the state's applying the emission performance rates directly to its affected EGUs in the form of standards of performance. As discussed further in section VIII on state plans, the states are charged with setting emission standards for the affected EGUs in their respective jurisdictions such that the affected EGUs operating under those standards together satisfy the requirements of the final emission guidelines and statute by meeting the emission performance rates or equivalent statewide emission performance goals, and thereby meet emission standards that reflect the BSER.

In the June 2014 proposal, the EPA proposed a set of state-specific emission rate-based CO_2 goals (in lbs of CO_2 per MWh of electricity generated). In addition, the EPA proposed emission rate-based CO_2 goals for areas of Indian country and U.S. territories with affected EGUs in a supplemental proposal on November 4, 2014. To provide flexibility to states, territories, tribes and implementing authorities, the proposals authorized each implementing authority to translate the form of the goal to a mass-based form (*i.e.,* goals expressed in terms of total tons of CO_2 per year from affected EGUs), as long as the translated goal was equivalent to the rate-based goal. Upon issuance of the proposed rule, the EPA continued the extensive outreach effort to stakeholders and members of the public that the EPA had engaged in for many months preceding the proposal. We also issued a notice of data availability (79 FR 67406, November 13, 2014) and technical support document (Docket ID: EPA–HQ–OAR–2013–0602–22187) to further clarify potential methods for the translation to a mass-based equivalent. The outreach provided additional opportunities for all jurisdictions with affected EGUs—both individually and in regional groups—as well as numerous industry groups and non-governmental organizations, to meet with the EPA and ask clarifying questions about, and give initial reactions to, the proposed components, requirements and timing of the rulemaking. As a result of the outreach and notice of data availability, the EPA received informed substantive comments for the EPA to consider for the final rule.

Numerous commenters encouraged and supported the EPA's efforts to allow states the maximum possible degree of flexibility in developing plans for their affected EGUs, either as a mass-based or rate-based CO_2 goal. States and other stakeholders supported the option to translate rate-based goals to mass-based goals for state plans and requested a simple and transparent method for determining mass-based statewide CO_2 goals that are equivalent to statewide rate-based CO_2 goals and thus reflective of the BSER. We received substantial comments on the potential methodologies for the translation of rate-based goals to mass-based goals. Several commenters requested that the EPA provide the translation to a statewide mass-based goals directly while others requested flexibility to translate to mass using a variety of methodologies and tools. In the context of these comments, the EPA has considered the appropriateness of rate-based and mass-based goals as an expression of BSER and their equivalence to the quantitative expression of BSER through the two CO_2 emission performance rates.

Based on the comments received, the EPA is providing a straightforward translation methodology from the CO_2 emission performance rates to yield statewide rate-based and mass-based CO_2 emission performance goals described in this section. The EPA is providing state mass-based goals in this final rule in place of having states determine the mass themselves. The mass-based goals are the result of a mathematical derivation that provides goals that are an equivalent expression of the BSER. Section VIII below discusses mechanisms for states to plan for and demonstrate achievement of the statewide CO_2 emission performance goals.

CAA section 111(d) requires states to submit a plan that establishes standards of performance for affected EGUs that implement the BSER. States meet the statutory requirements of CAA section 111(d) and the requirements of the final emission guidelines by submitting emission standards for affected EGUs that meet the performance rates, which reflect the application of the BSER as determined by the EPA. Therefore, as a first step for states that choose to submit plans that meet the rate-based or mass-based goals, the goals must be determined to have equivalence as an application of the BSER. For the rate-based and mass-based state goals provided here, this equivalence is evident in the mathematical derivation of the goals, as is described in sections VII.B and VII.C below.

Further (as described in section VIII.J), the state plan must demonstrate that it has measures in place to ensure that any alternative to the performance rates (*i.e.,* rate-based or mass-based state goals that it uses to establish standards of performance) does not result in affected EGUs' failing to implement either the BSER measure themselves or alternative methods of compliance with emission standards that achieve equivalent reductions in emissions or carbon intensity. The EPA has identified one way in which affected EGUs could fail to meet, at a minimum, of the emission performance levels that would result from implementing the BSER, which state plans must do.

Specifically, the EPA has determined that the three building blocks are the BSER, including shifting generation from an affected EGU to a lower-emitting affected EGU or to a non-emitting EGU and that states are required to establish standards of performance that require affected EGUs to achieve, at a minimum, the emission performance levels that reflect the BSER (recognizing that affected sources may choose from a range of equivalent actions (*e.g.,* undertaking the measures included in the building blocks, shifting generation to low-emitting or zero-emitting resources not included in the building blocks or achieving demand-side EE or transmission efficiency—either through operational undertakings, direct investment or emissions trading). Substantial shifting of generation from affected EGUs to new fossil fuel-fired EGUs, such as new NGCC units, represents a deviation from implementing the BSER or its compliance equivalent.

Since the two subcategory-specific emission performance rates represent the BSER, states that established standards of performance at or below those rates, by definition, would be implementing state plans that created no risk that affected EGUs would shift generation to new fossil-fired EGUs to an extent that would deviate from the BSER. Similarly, the EPA has determined that states using rate-based goals as the foundation for plans implementing the BSER are unlikely to foster generation shifts to new fossil fuel-fired sources to an extent that would deviate from the BSER. In contrast, however, EPA analysis has identified a concern that a mass-based state plan that failed to include appropriate measures to address leakage could result in failure to achieve emission performance levels consistent with the BSER.[759] Section VII.B describes how the form of the rate-based state goals minimizes the risk of generation shifts to new fossil fuel-fired sources, or ''leakage,'' by providing affected EGUs with a sufficient incentive to run, similar to the performance rates. Section VII.D. discusses how there is a potential for leakage under mass-based state goals because affected EGUs are incented to operate in a manner—in particular, by shifting generation to new NGCC units (as opposed to shifting generation as contemplated by the BSER or undertaking equivalent alternative compliance actions)—that would result in negating the equivalence with the emission performance rates and thus the BSER, and specifies that requirements are needed in mass-based implementation to assure those incentives are realigned.[760]

B. Reconstituting Statewide Rate-Based CO_2 Emission Performance Goals From the Subcategory-Specific Emission Performance Rates

In order to provide states flexibility for planning purposes, the EPA is providing a state-specific averaging of the subcategory-specific emission performance rates to determine a statewide goal. While the emission performance rates reflect the quantification of performance based on the BSER and embody the reductions estimated under building blocks 1, 2, and 3, the state goals reflect an equivalent approach through which states may choose to adopt and implement those subcategory-specific performance rates.

The EPA quantified the potential reductions of the BSER in the subcategory-specific emission performance rates established in section VI. These rates themselves reflect the reduction potential expected in emission rates under the BSER for each year from 2022 to 2030. To establish state goals, the EPA applied these rates to the baseline generation levels to estimate the affected fleet emission rate that would occur if all affected EGUs in the fleet met the subcategory-specific rates. This step respects the flexibility of sources to meet the rates in any manner that they see fit (*e.g.,* on-site abatement technology, fuel switching, co-firing, credit purchase, etc.), and does not limit them to their building block assumptions. For example, the EPA derived the statewide rate-based CO_2 emission performance goals for 2030 by multiplying the fossil steam emission performance rate for 2030 by the baseline fossil steam generation in a state and multiplying the NGCC emission performance rate for 2030 by the baseline NGCC generation in a state. The resulting emissions for fossil steam and NGCC are then added together for each state. This emission total is divided by that state's baseline generation values from the likely affected EGUs in order to develop a state's rate-based CO_2 emission performance goal for 2030. This blended rate reflects the collective emission rate a state may expect to achieve when its baseline fleet of likely affected EGUs continues to operate at baseline levels while meeting its subcategory-specific emission performance rates reflecting the BSER. The EPA believes that using the adjusted 2012 baseline is the most appropriate way to combine the rates. First, as explained in Section VI, the EPA believes there are significant advantages to using real world data to set a baseline rather than using projected data. The adjusted 2012 data is the logical starting point because it is the data that all of the emission performance rates (discussed in Section VI) are based upon. Furthermore, it is clear that generation shifts as projected under the BSER are not the appropriate baseline. The emission performance rates already factor in the BSER assumptions about changes in generation (*e.g.,* implementation of building block 2 significantly lowers the emission performance rate for fossil-steam units). If, on top of that, changes in generation were factored into the calculation of a combined rate, those changes in generation would be factored into the combined rate twice (once when calculating the individual emission performance rates and a second time, when incorporating those rates into a combined state rate).

This step is repeated for each year from 2022–2029 using the emission performance rates calculated for each of those years in the previous section. The EPA also repeats this step for the interim state goal using the interim subcategory rates. The EPA then averages together the annual amounts in increments of 3 years, 3 years, and 2 years for 2022–2024, 2025–2027, and 2028–2029 to estimate emission rate averages for those periods that can provide one illustrative pathway for states to consider in meeting their interim goals. These 3- and 2-year increment are not regulatory guidelines or equivalents for interim goals, but rather benchmarks for demonstrating plan performance as discussed in Section VIII.F illustrative of a potential gradual reduction compliance strategy that states may use to reach their interim and final state goals.

As described in the steps above, the statewide goals represent an equivalent arithmetic combination of the subcategory-specific emission performance rates, weighted by the historical baseline generation levels upon which the BSER is premised. In particular, as discussed above, the method for deriving these goals assures equivalent flexibility by applying the CO_2 emission performance rates to the baseline levels, which respects the flexibility of affected EGUs to meet the rates in whatever way they wish. This corresponding treatment of affected EGUs based on the adjusted 2012 baseline ensures sufficient incentive to affected existing EGUs to generate and thus avoid leakage, similar to the CO_2

[759] See Chapter 3 of the Regulatory Impact Analysis for more information on this analysis, which is available in the docket.

[760] The specific mass-based plan requirements are explained in detail in section VIII.J.

emission performance rates (this is further discussed in section VII.D below). Consequently, the statewide goals are equivalent to the CO_2 emission performance rates and are thus an equivalent expression of the BSER. The rate-based statewide goals are provided below in Table 12.

C. Quantifying Mass-Based CO_2 Emission Performance Goals From the Statewide Rate-Based CO_2 Emission Performance Goals

The EPA is also establishing mass-based statewide CO_2 emission performance goals for each state, which are provided below in Table 13. For state plans choosing to meet a mass-based goal, such a goal must be equivalent to the CO_2 emission performance rates in their application of the BSER, as required by the statute and the final emission guidelines. In the following discussion we describe the mathematical calculations that provide an equivalent expression of the BSER. In evaluating the equivalence of the form of mass goals, the EPA must also recognize the impact that the form of the standard has on the relative incentives that the implementation of these goals provides to affected and unaffected EGUs. This section specifies how we have established a quantitative basis for mass goals that is equivalent to CO_2 emission performance rates. The next section (section VII.D) specifies how we require state plans to ensure equivalence to the CO_2 emission performance rates through certain requirements that realign the potential difference in incentives provided to affected and unaffected EGUs to generate under a mass-based implementation compared to a rate-based implementation that could result in leakage.

The starting place for quantifying mass-based statewide CO_2 emission performance goals is the emission amounts directly represented in the numerator of the statewide rate-based CO_2 emission performance goals. Each state-specific emission amount is the product of the fossil steam emission performance rate and historical fossil steam generation, added to the product of the NGCC emission performance rate and historical NGCC generation. The resulting emission amounts for each state represent the emissions associated with rate-based compliance at historical generation levels.

However, under a rate-based state plan, all affected EGUs have the opportunity to increase utilization, provided that sufficient emission reduction measures are available to maintain the necessary ratio of emissions to generation as quantified by the subcategory-specific emission performance rates. Due to the nature of the emission performance rate methodology, which selects the highest of the three interconnection-based values for each source category as the CO_2 emission performance rate, there are cost-effective lower-emitting generation opportunities quantified under the building blocks that are not necessary for affected EGUs in the Western and Texas interconnections to demonstrate compliance at historical generation levels. The EPA recognizes that these lower-emitting generation opportunities are available to affected EGUs at a national level as a means to increase their own output (and, as a result, their own emissions) while maintaining the relevant emission performance rate. To afford affected EGUs subject to a mass-based goal similar compliance flexibility as EGUs subject to a rate-based goal, the EPA has quantified the emissions associated with the potential realization of these lower-emitting generation opportunities and incorporated those additional tons into each state's mass-based goal.[761] Because the derivation of these mass-based goals respects the arithmetic of the subcategory-specific emission performance rates and the flexibility of affected EGUs to achieve those rates while utilizing up to the full potential quantified in the building blocks, the derivation of these mass-based state goals offers an equivalent expression of BSER in mass form.

The mass goals for existing sources are presented in Table 13. Although their derivation is equivalent to the subcategory-specific emission performance rates, in order to maintain this equivalence in the establishment of emission standards in state plans mass goals must be implemented in combination with requirements that align the incentives provided to affected and unaffected EGUs, specifically in order to prevent leakage.

D. Addressing Potential Leakage in Determining the Equivalence of State-Specific CO_2 Emission Performance Goals

As described in section VI, the subcategory-specific emission performance rates reflect the BSER as determined by the EPA. This final rule allows states to establish emission standards that meet either rate-based or mass-based state goals. As stated above, rate-based state goals were published in the proposed rule, and commenters not only supported having the flexibility to use rate-based goals or mass-based goals as part of state plans, but also requested that the EPA include mass-based goals in this final rule. But to ensure the equivalence of mass-based state goals, we must consider how the form of the goal affects its implementation and how the incentives it provides to affected EGUs on the interstate grid affect whether or not the BSER is fully implemented.

Because of the integrated nature of the utility power sector, the form of the emission performance requirements for existing sources may ultimately impact the relative incentives to generate and emit at affected EGUs as opposed to shifting generation to new sources, with potential implications for whether a given set of standards of performance is, at a minimum, consistent with the BSER, in the context of overall emissions from the sector. In this context, we, again, define as ''leakage'' the potential of an alternative form of implementation of the BSER (*e.g.,* the rate-based and mass-based state goals) to create a larger incentive for affected EGUs to shift generation to new fossil fuel-fired EGUs relative to what would occur when the implementation of the BSER took the form of standards of performance incorporating the subcategory-specific emission performance rates representing the BSER. In the proposal, the EPA recognized that the statutory construction regarding the BSER is to reduce emissions, which can be achieved through shifts of generation. Movement of generation between and among sources is needed to produce overall reductions, particularly movement from higher-emitting affected EGUs to lower-emitting affected EGUs, and from all affected EGUs to zero-emitting RE. In all of these cases, the fossil sources involved in these generation shifts are subject to obligations under this final rule.[762]

However, leakage, where shifts in generation to unaffected fossil fuel-fired sources result in increased emissions, relative to what would have happened

[761] For more detail on this methodology, please refer to the CO_2 Emission Performance Rate and Goal Computation TSD for CPP Final Rule, which is available in the docket.

[762] The final rule includes state plan conditions to prevent perverse incentives that could otherwise result in greater overall emissions when generation shifts across affected EGUs. For example, states that wish to engage in rate-based trading through an emission standards plan type must adopt plans designed to achieve either a common rate-based state goal or the subcategory-specific emission performance rates (see section VIII.L). Such a state plan condition avoids encouraging generation to shift from a state with a relatively lower state goal to a state with a relatively higher state goal solely as a response to the form of CPP implementation.

had generation shifts consistent with the BSER occurred, is contrary to this construction. Therefore, if the form of the standard does not address leakage or incents the kinds of generation shifts that we identify as leakage, the states must otherwise address leakage in order to ensure that the standards of performance applied to the affected EGUs are, in the aggregate, at least equivalent with the emission performance rates, and therefore appropriately reflect the BSER as required by the statute. Commenters noted that shifting generation and emissions from existing sources to new sources undermined the intent of this rule and the overall emission reduction goals, and that requiring states to address leakage is consistent with the obligation that states establish standards of performance that, in the aggregate, at a minimum, reflect the BSER for affected EGUs operating in the interconnected electricity sector.

This section specifically addresses the need for state plans designed to achieve either rate- or mass-based state goals to ensure that their plans succeed in implementing standards of performance that reflect the BSER by minimizing the difference in incentives provided to affected EGUs and new sources to generate in order to maintain equivalent emission performance with the CO_2 emission performance rates.

Rate-based goals do not in our view implicate leakage to an extent that would negate or limit the implementation of the BSER because under a rate-based state goal, similar to the subcategory-specific emission performance rates, existing lower-emitting affected EGUs, primarily NGCC units, are incentivized to increase their utilization in order to improve the average emission rates of affected EGUs overall. New units that are not subject to the rate-based state goal, and that are not an allowable measure for adjusting an EGU's CO_2 emission rate, will not have this incentive to increase utilization, and as a result, the imposition of a rate-based goal on affected EGUs is unlikely to encourage increased generation and emissions from unaffected new EGUs. The form of the rate-based state goals provides an equivalent or greater incentive to affected existing EGUs as they are provided in the CO_2 emission performance rates, and similarly avoid the potential for leakage. Under both approaches, existing NGCC units can generate ERCs. These ERCs provide an economic incentive to utilize existing NGCC units rather than new NGCC units. Further, ERCs from incremental RE incentivize new renewable generation over new NGCC generation. Both of these features, which exist in the context of implementation with a state rate-based goal or CO_2 emission performance rates, provide significant incentives to ensure that, consistent with the BSER, shifting of generation does not occur between existing fossil fuel-fired units and new NGCC units.

Mass-based goals for existing sources, however, incur a leakage risk to the extent that they incent generation shifts from affected EGUs to unaffected fossil fuel-fired sources in a way that negates the reliance on the BSER. In contrast to various forms of rate-based implementation, mass-based implementation in a state plan can unintentionally incentivize increased generation from unaffected new EGUs as a substitute action for reducing emissions at units subject to the existing source mass goal in ways that would negate the implementation of the BSER and would result in increased emissions. This occurs because, unlike in a rate-based system where rate-based averaging lowers the cost of generation from existing NGCC units relative to generation from new NGCC units, in a mass-based system the allowance price increases the cost of generation from existing NGCC units relative to generation from new NGCC units. The extent to which electricity providers opt to rely on this increase in unaffected new source utilization as a substitute for improving the emissions performance across existing sources would be fundamentally inconsistent with relying on the BSER to reduce emissions as the basis of the subcategory-specific emission performance rates.

As a result, notwithstanding the fact that mass goals for existing sources are quantified in a way that is an equivalent expression of the BSER, the form of mass goals is only equivalent if leakage is satisfactorily addressed in the state plan's establishment of emission standards and implementation measures. The EPA is therefore requiring that states adopting a mass-based state plan include requirements that address leakage, or otherwise provide additional justification that leakage would not occur under the state's implementation of mass-based emission standards. This requirement enables states to establish standards of performance that meet a mass-based goal equivalent to the performance rates and therefore reflect the BSER, as required by section 111(d). The required demonstration and options for state plans to minimize leakage are discussed in detail in section VIII.J of this preamble.

Further supporting the need for this requirement, the EPA has evaluated the mass goals in concert with some of the options to minimize leakage described in that section. As mentioned above, the EPA analysis identified a concern regarding leakage in a mass-based approach, namely that the mass-based implementation without measures to address leakage produced higher generation from new NGCC units and lower emission performance when compared to a rate-based implementation. Further analysis where implementation of the mass-based goals was coupled with measures to address leakage produce utility power sector emissions performance that is similar to emissions performance under the rate goals.[763]

E. State Plan Adjustments of State Goals

The EPA notes that it is the emission performance rates in section VI that constitute the application of the BSER to the affected EGUs and serve as the chief regulatory requirement of this rulemaking. The statewide CO_2 rate-based and mass-based emission performance goals provided here are metrics that states may choose to adopt when demonstrating compliance at the state level, and states may consider these goals when determining how to set unit-level compliance requirements. The EPA believes that the regional nature of determining the emission performance rates encompasses a large population size and makes it robust against unit-level variation and unit-level inventory discrepancies. The EPA does acknowledge that state-level rate-based goals or mass-based goals may be sensitive to applicability changes within a state's affected population. In the proposal, the EPA used a baseline that aggregated data for what it believed to be affected units and asked states, companies and other stakeholders to provide corrections in their comments. We received input from many commenters and have corrected information as appropriate. Therefore, we believe the baseline to be accurate. However, if subsequent applicability review or formal applicability determinations change the status of units in regards to being affected or unaffected by this rulemaking, states can, via state plan submittal or revision, adjust their statewide rate or mass goal to reflect this change of status.

This adjustment flexibility provision is based on comments received at proposal. For example, some

[763] See Chapter 3 of the Regulatory Impact Analysis for more information on this analysis, which is available in the docket.

stakeholders noted that the affected status of particular units was unclear. The EPA recognizes that all the necessary data to determine the affected status of some units may not be available at this time. As stated above, the EPA does not believe unit-level variation or inclusion/exclusion disparities between baseline inventory and affected units will impact the regionally determined emission performance rates discussed in the previous section. However, variations in baseline data or inventory may have an impact on the *state-level* rate-based or mass-based goals provided in this section. Therefore, the EPA is allowing the flexibility for states to demonstrate the need for this type of adjustment under the justifications above and utilize an adjusted value for compliance purposes when submitting or revising its state plan. The EPA will evaluate the appropriateness of such an adjusted value based on the state's demonstration and evaluate the approvability of a plan or plan revision accordingly.

Rate-based statewide CO_2 emission performance goals are listed below in Table 12. Mass-based statewide CO_2 emission performance goals are found in Table 13.

TABLE 12—STATEWIDE [764] RATE-BASED CO_2 EMISSION PERFORMANCE GOALS

[Adjusted output-weighted-average pounds of CO_2 per net MWh from all affected fossil fuel-fired EGUs]

State name	Interim goal—Step 1	Interim goal—Step 2	Interim goal—Step 3	Interim goal	Final goal
Alabama	1,244	1,133	1,060	1,157	1,018
Arizona *	1,263	1,149	1,074	1,173	1,031
Arkansas	1,411	1,276	1,185	1,304	1,130
California	961	890	848	907	828
Colorado	1,476	1,332	1,233	1,362	1,174
Connecticut	899	836	801	852	786
Delaware	1,093	1,003	946	1,023	916
Florida	1,097	1,006	949	1,026	919
Georgia	1,290	1,173	1,094	1,198	1,049
Idaho	877	817	784	832	771
Illinois	1,582	1,423	1,313	1,456	1,245
Indiana	1,578	1,419	1,309	1,451	1,242
Iowa	1,638	1,472	1,355	1,505	1,283
Kansas	1,654	1,485	1,366	1,519	1,293
Kentucky	1,643	1,476	1,358	1,509	1,286
Lands of the Fort Mojave Tribe	877	817	784	832	771
Lands of the Navajo Nation	1,671	1,500	1,380	1,534	1,305
Lands of the Uintah and Ouray Reservation	1,671	1,500	1,380	1,534	1,305
Louisiana	1,398	1,265	1,175	1,293	1,121
Maine	888	827	793	842	779
Maryland	1,644	1,476	1,359	1,510	1,287
Massachusetts	956	885	844	902	824
Michigan	1,468	1,325	1,228	1,355	1,169
Minnesota	1,535	1,383	1,277	1,414	1,213
Mississippi	1,136	1,040	978	1,061	945
Missouri	1,621	1,457	1,342	1,490	1,272
Montana	1,671	1,500	1,380	1,534	1,305
Nebraska	1,658	1,488	1,369	1,522	1,296
Nevada	1,001	924	877	942	855
New Hampshire	1,006	929	881	947	858
New Jersey	937	869	829	885	812
New Mexico *	1,435	1,297	1,203	1,325	1,146
New York	1,095	1,005	948	1,025	918
North Carolina	1,419	1,283	1,191	1,311	1,136
North Dakota	1,671	1,500	1,380	1,534	1,305
Ohio	1,501	1,353	1,252	1,383	1,190
Oklahoma	1,319	1,197	1,116	1,223	1,068
Oregon	1,026	945	896	964	871
Pennsylvania	1,359	1,232	1,146	1,258	1,095
Rhode Island	877	817	784	832	771
South Carolina	1,449	1,309	1,213	1,338	1,156
South Dakota	1,465	1,323	1,225	1,352	1,167
Tennessee	1,531	1,380	1,275	1,411	1,211
Texas	1,279	1,163	1,086	1,188	1,042
Utah *	1,483	1,339	1,239	1,368	1,179
Virginia	1,120	1,026	966	1,047	934
Washington	1,192	1,088	1,021	1,111	983
West Virginia	1,671	1,500	1,380	1,534	1,305
Wisconsin	1,479	1,335	1,236	1,364	1,176
Wyoming	1,662	1,492	1,373	1,526	1,299

* Excludes EGUs located in Indian country within the state.

[764] The EPA has not developed statewide rate-based or mass-based CO_2 emission performance goals for Vermont and the District of Columbia because current information indicates those jurisdictions have no affected EGUs.

TABLE 13—STATEWIDE MASS-BASED CO_2 EMISSION PERFORMANCE GOALS

[Adjusted output-weighted-average tons of CO_2 from all affected fossil fuel-fired EGUs]

State	Interim goal—Step 1	Interim goal—Step 2	Interim goal—Step 3	Interim goal	Final goal
Alabama	66,164,470	60,918,973	58,215,989	62,210,288	56,880,474
Arizona*	35,189,232	32,371,942	30,906,226	33,061,997	30,170,750
Arkansas	36,032,671	32,953,521	31,253,744	33,683,258	30,322,632
California	53,500,107	50,080,840	48,736,877	51,027,075	48,410,120
Colorado	35,785,322	32,654,483	30,891,824	33,387,883	29,900,397
Connecticut	7,555,787	7,108,466	6,955,080	7,237,865	6,941,523
Delaware	5,348,363	4,963,102	4,784,280	5,062,869	4,711,825
Florida	119,380,477	110,754,683	106,736,177	112,984,729	105,094,704
Georgia	54,257,931	49,855,082	47,534,817	50,926,084	46,346,846
Idaho	1,615,518	1,522,826	1,493,052	1,550,142	1,492,856
Illinois	80,396,108	73,124,936	68,921,937	74,800,876	66,477,157
Indiana	92,010,787	83,700,336	78,901,574	85,617,065	76,113,835
Iowa	30,408,352	27,615,429	25,981,975	28,254,411	25,018,136
Kansas	26,763,719	24,295,773	22,848,095	24,859,333	21,990,826
Kentucky	76,757,356	69,698,851	65,566,898	71,312,802	63,126,121
Lands of the Fort Mojave Tribe	636,876	600,334	588,596	611,103	588,519
Lands of the Navajo Nation	26,449,393	23,999,556	22,557,749	24,557,793	21,700,587
Lands of the Ute Tribe of the Uintah and Ouray Reservation	2,758,744	2,503,220	2,352,835	2,561,445	2,263,431
Louisiana	42,035,202	38,461,163	36,496,707	39,310,314	35,427,023
Maine	2,251,173	2,119,865	2,076,179	2,158,184	2,073,942
Maryland	17,447,354	15,842,485	14,902,826	16,209,396	14,347,628
Massachusetts	13,360,735	12,511,985	12,181,628	12,747,677	12,104,747
Michigan	56,854,256	51,893,556	49,106,884	53,057,150	47,544,064
Minnesota	27,303,150	24,868,570	23,476,788	25,433,592	22,678,368
Mississippi	28,940,675	26,790,683	25,756,215	27,338,313	25,304,337
Missouri	67,312,915	61,158,279	57,570,942	62,569,433	55,462,884
Montana	13,776,601	12,500,563	11,749,574	12,791,330	11,303,107
Nebraska	22,246,365	20,192,820	18,987,285	20,661,516	18,272,739
Nevada	15,076,534	14,072,636	13,652,612	14,344,092	13,523,584
New Hampshire	4,461,569	4,162,981	4,037,142	4,243,492	3,997,579
New Jersey	18,241,502	17,107,548	16,681,949	17,426,381	16,599,745
New Mexico*	14,789,981	13,514,670	12,805,266	13,815,561	12,412,602
New York	35,493,488	32,932,763	31,741,940	33,595,329	31,257,429
North Carolina	60,975,831	55,749,239	52,856,495	56,986,025	51,266,234
North Dakota	25,453,173	23,095,610	21,708,108	23,632,821	20,883,232
Ohio	88,512,313	80,704,944	76,280,168	82,526,513	73,769,806
Oklahoma	47,577,611	43,665,021	41,577,379	44,610,332	40,488,199
Oregon	9,097,720	8,477,658	8,209,589	8,643,164	8,118,654
Pennsylvania	106,082,757	97,204,723	92,392,088	99,330,827	89,822,308
Rhode Island	3,811,632	3,592,937	3,522,686	3,657,385	3,522,225
South Carolina	31,025,518	28,336,836	26,834,962	28,969,623	25,998,968
South Dakota	4,231,184	3,862,401	3,655,422	3,948,950	3,539,481
Tennessee	34,118,301	31,079,178	29,343,221	31,784,860	28,348,396
Texas	221,613,296	203,728,060	194,351,330	208,090,841	189,588,842
Utah*	28,479,805	25,981,970	24,572,858	26,566,380	23,778,193
Virginia	31,290,209	28,990,999	27,898,475	29,580,072	27,433,111
Washington	12,395,697	11,441,137	10,963,576	11,679,707	10,739,172
West Virginia	62,557,024	56,762,771	53,352,666	58,083,089	51,325,342
Wisconsin	33,505,657	30,571,326	28,917,949	31,258,356	27,986,988
Wyoming	38,528,498	34,967,826	32,875,725	35,780,052	31,634,412

* Excludes EGUs located in Indian country within the state.

F. Geographically Isolated States and Territories With Affected EGUs

Alaska, Hawaii, Guam, and Puerto Rico constitute a small set of states and U.S. territories representing about one percent of total U.S. EGU GHG emissions. Based on the current record, the EPA does not possess all of the information or the analytic tools needed to quantify the application of the BSER for these states and territories, particularly data regarding RE costs and performance characteristics needed for building block 3 of the BSER. The NREL data for RE that the EPA is relying upon for building block 3 does not cover the non-contiguous states and territories.

The EPA acknowledges that NREL has collaborated with the state of Hawaii to provide technical expertise in support of the state's aggressive goals for clean energy, including analyses of the grid integration and transmission of solar and wind resources.[765] The EPA also recognizes that there are studies and data for some renewable resources in some of the other non-contiguous jurisdictions. However, taken as a whole, the data we currently possess do not allow us to quantify the emissions reductions available from building block 3 using the same methodology used for

[765] Hawaii Solar Integration Study, NREL Technical Report NREL/TP–5500–57215, June 2013. Available at *http://www.nrel.gov/docs/fy13osti/57215.pdf*.

the contiguous states encompassed by the three interconnections. Lastly, the IPM model used to support the EPA's analysis is geographically limited to the contiguous U.S. As a result of these factors, the EPA currently lacks the necessary analytic resources to set emission performance goals for these areas.

Because of the lack of suitable data and analytic tools needed to develop area-appropriate building block targets as defined in section V, the EPA is not setting CO_2 emission performance goals for Alaska, Hawaii, Guam, or Puerto Rico in this final rule at this time. The EPA believes it is within its authority to address performance goals only for the contiguous U.S. states in this final rule. Under section 111(d), the EPA is not required, at the time that the EPA promulgates section 111(b) requirements for new sources, to promulgate emission guidelines for all of the sources that, if they were new sources, would be subject to the section 111(b) requirements if there is a reasonable basis for deferring certain groups of sources. As discussed, in this rule, the EPA has a reasonable basis for deferring setting goals for these four jurisdictions. In addition, the Courts have recognized the authority of agencies to develop regulatory programs in step-by-step fashion. As the U.S. Supreme Court noted in *Massachusetts* v. *EPA,* 549 U.S. 497, 524 (2007): ''Agencies, like legislatures, do not generally resolve massive problems in one fell regulatory swoop;'' and instead they may permissibly implement such regulatory programs over time, ''refining their preferred approach as circumstances change and as they develop a more nuanced understanding of how best to proceed.'' [766]

The EPA recognizes, however, that EGUs in Alaska, Hawaii, Puerto Rico, and Guam emit CO_2 and that there are opportunities to reduce the carbon intensity of generation in those areas over time. We recognize further that there are efforts underway to increase the use of RE in these jurisdictions. In particular, we recognize that Hawaii has tremendous opportunities for RE and has adopted very ambitious goals: 40 percent clean energy by 2030 and 100 percent by 2045. Since 2008, Alaska has apportioned in excess of $1.34 billion pursuing its aspirational goal of 50 percent of the state's total yearly electric load from renewable and alternative energy sources by 2025. Puerto Rico's goal is to achieve 20 percent RE sales by 2035, and the territory is working hard to meet the requirements of the Mercury and Air Toxics Standards, which will reduce emissions from its power plants substantially. Guam's RPS is to achieve 25 percent REsales by 2035.

The agency intends to continue to consider these issues and determine what the appropriate BSER is for these areas. As part of that effort, the agency will investigate sources of information and types of analysis appropriate to devise the appropriate levels for building block 3 and BSER performance levels. Because we recognize that these areas face some of the most urgent climate change challenges, severe public health problems from air pollution and some of the highest electricity rates in the U.S., the EPA is committed to obtaining the right information to quantify the emission reductions that are achievable in these four areas and putting goals in place soon.

VIII. State Plans

A. Overview

After the EPA establishes the emission guidelines that set forth the BSER, each state with one or more affected EGUs [767] shall then develop, adopt and submit a state plan under CAA section 111(d) that establishes standards of performance for the affected EGUs in its jurisdiction in order to implement the BSER. Starting from the foundation of CAA section 111(d) and the EPA's implementing regulations (40 CFR part 60 subpart B), the EPA's proposal laid out a number of options, variations and flexibilities that were intended to provide states and affected EGUs the ability to design state plans that accorded with states' specific situations and policies (now and in the future), and to ensure reliability and affordability of electricity across the system and for all ratepayers. The proposal has prompted numerous discussions between and among stakeholders, especially states and groups of states, including state environmental and energy regulators and policy officials. The EPA has received many comments from a wide range of stakeholders seeking a final rule that afforded freedom and flexibility to consider a wide range of standards of performance to implement the BSER, but also providing significant feedback on the elements and options in the proposal and constructive suggestions for alternative approaches. The EPA has carefully considered all of this input, and is finalizing emission guidelines that continue to provide a variety of options for states to fashion their plans in ways legally supportable by the CAA, while also making certain adjustments to address key comments.

The next few paragraphs present an overview of the main features of the final emission guidelines, highlighting key changes from proposal. In the rest of this section, we describe in detail the various elements of the final emission guidelines' requirements for state plans.

The proposal contained rate-based goals for each state, reflecting a blended reduction target for that state's fossil fired EGUs, and provided that states could either meet that rate-based goal or convert it to a mass-based equivalent goal. Reflecting the final BSER described in section V and in response to many comments desirous that the EPA establish mass-based goals in the final rule, these final guidelines include three approaches that states may adopt for purposes of implementing the BSER, any one of which a state may use in its plan. These are: (1) Establishing standards of performance that apply the subcategory-specific CO_2 emission performance rates to their affected EGUs, (2) adopting a combination of standards and/or other measures that achieve state-specific rate-based goals that represent the weighted aggregate of the CO_2 emission performance rates applied to the affected EGUs in each state, and (3) adopting a program to meet mass-based CO_2 emission goals that represent the equivalent of the rate-based goal for each state. These alternatives, as well as the other options we are finalizing, ensure that both states and affected EGUs enjoy the maximum flexibility and latitude in meeting the requirements of the emission guidelines and that the BSER is fully implemented by each state.

In the proposal, we provided two designs for state plans: One where all the reduction obligations are placed directly on the affected EGUs and one, which we called the ''portfolio approach,'' that could include measures to be implemented, in whole or in part, by parties other than the affected EGUs. In the final guidelines, we retain that

[766] *See, e.g., Grand Canyon Air Tour Coalition* v. *F.A.A.,* 154 F.3d 455, 471 (D.C. Cir. 1998) (ordinarily, agencies have wide latitude to attack a regulatory problem in phases and that a phased attack often has substantial benefits); *National Association of Broadcasters* v. *FCC,* 740 F.2d 1190, 121–11 (D.C. Cir. 1984) (''We have therefore recognized the reasonableness of [an agency's] decision to engage in incremental rulemaking and to defer resolution of issues raised in a rulemaking. . . .'').

[767] As stated previously, states with one or more affected EGUs will be required to develop and implement plans that set emission standards for affected EGUs. The CAA section 111(d) emission guidelines that the EPA is promulgating in this action apply to only the 48 contiguous states and any Indian tribe that has been approved by the EPA pursuant to 40 CFR 49.9 as eligible to develop and implement a CAA section 111(d) plan. Because Vermont and the District of Columbia do not have affected EGUs, they will not be required to submit a state plan.

basic choice, but with some modifications to respond to comments we received, especially on the portfolio approach. In their plans, states will be able to choose either to impose federally enforceable emission standards that fully meet the emission guidelines directly on affected EGUs (the ''emission standards'' approach) or to use a ''state measures'' approach, which would be composed, at least in part, of measures implemented by the state that are not included as federally enforceable components of the plan but result in the affected EGUs meeting the requirements of the emission guidelines. A state measures type plan must include a backstop of federally enforceable standards on affected EGUs that fully meet the emission guidelines and that would be triggered if the state measures fail to result in the affected EGUs achieving on schedule the required emission reductions.

States that choose an emission standards plan may establish as standards of performance for their affected EGUs the subcategory-specific CO_2 emission performance rates, which express the BSER.[768] This would satisfy the requirement described in section VIII.D.2.a.3 that a state demonstrate its plan would achieve the CO_2 emission performance rates; in this case, no further demonstration would be necessary. Alternatively, a state may establish emission standards for affected EGUs at different levels from the uniform subcategory-specific emission performance rates, provided that when implemented, the emission standards achieve the CO_2 emission performance rates or state rate- or mass-based CO_2 emission goal set forth by the EPA for the state. States that adopt differential standards of performance among their affected EGUs must demonstrate that, in the aggregate, the differential standards of performance will result in their affected EGUs meeting the CO_2 emission performance rates, the state's rate-based CO_2 emission goal or its mass-based CO_2 emission goal.

In the proposal, we proposed that states could use the portfolio approach to meet either a rate- or mass-based goal. In these final emission guidelines, the state measures approach is available only for a state choosing a mass-based CO_2 emission goal, to provide certainty that the state measures are achieving the required emission reductions. Similar to emission standards plans with differential standards of performance, states that adopt state measures plans must demonstrate that the state measures, alone or in conjunction with any federally enforceable emission standards on affected EGUs also included in the state plan, will result in the affected EGUs in the state meeting the state's mass-based CO_2 emission goal. A ''state measures'' type plan must also include a backstop provision—triggered if, during the interim period, the state plan fails to achieve the emission reduction trajectory identified in the plan or if, during the final phase, the state plan fails to meet the final state mass-based CO_2 emission goal—that would impose federally enforceable emission standards on the affected EGUs adequate to meet the emission guidelines when fully implemented.

The final guidelines reflect the changes to the timing of the reductions within the interim period, which is laid out in section V as part of the determination of the BSER. States may adopt in their plans emission reduction trajectories different from the illustrative three-step trajectory included in these guidelines for purposes of creating a ''glide path'' between 2022 and 2029, provided that the interim and final CO_2 emission performance rates or state CO_2 emission goals are met.

We recognize that while we are establishing 2022 as the date by which the period for mandatory reductions must start as part of our BSER determination, utilities and other parties are moving forward with projects that reduce emissions of CO_2 from affected EGUs. We received numerous comments urging us to allow credit for these early actions. The final guidelines encourage those early reductions, by making clear that states may, in their plans, allow EGUs to use allowances or ERCs generated through the CEIP. The final guidelines also require that states include in their final plans a schedule of the actions they will be taking to ensure that the period for mandatory reductions will begin as required starting in 2022, and submit a progress report on those actions.

For all types of plans, the final guidelines make clear that states may adopt programs that allow trading among affected EGUs. The final guidelines retain the flexibility for states to do individual plans, or to join with other states in a multi-state plan. In addition, and in response to comments from many states and other stakeholders, the guidelines provide that states may design their programs so that they are ''ready for interstate trading,'' that is, that they contain features necessary and suitable for their affected EGUs to engage in trading with affected EGUs in other ''trading ready'' states without the need for formal arrangements between individual states.

We have been mindful of the concerns raised by stakeholders about reliability. The final BSER, especially the changes in the timing of the interim period, substantially address these concerns. The flexibilities provided for the design of state plans, including the ability to use trading programs, further enhance system reliability. We have included, as an additional assurance, a reliability safety valve for use where the built-in flexibilities are not sufficient to address an immediate, unexpected reliability situation.

The EPA believes that all the flexibilities provided in the final rule are not only appropriate, but will enhance the success of the program. CO_2 is a global pollutant, and where and when the reductions occur is not as significant to the environmental outcome as compared to many other pollutants. The flexibilities provided in the final guidelines will better reflect the unique interconnectedness of the electricity system, and will allow states and EGUs to reduce CO_2 emissions while maintaining reliability and affordability for all consumers.

In developing the plan, the state rulemaking process must meet the minimum public participation requirements of the implementing regulations as applicable to these guidelines, including a public hearing and meaningful engagement with all members of the public, including vulnerable communities. In the community and environmental justice considerations section, section IX of this preamble, the EPA addresses the actions that the agency is taking to help ensure that vulnerable communities are not disproportionately impacted by this rule. These actions include conducting a proximity analysis, setting expectations for states to engage meaningfully with vulnerable communities and requiring that they describe their plans for doing so as they develop their state plans, providing communities with access to additional resources, providing communities with information on federal programs and resources available to them, recommending that states take a multi-pollutant planning approach that examines the potential impacts of co-pollutants on overburdened communities, and conducting an assessment to determine if any localized air quality impacts need to be further addressed. Additionally, the EPA outlines the continued engagement that it will be conducting with states and communities throughout the state plan development process.

[768] Rate-based and mass-based emission standards may incorporate the use of emission trading.

As discussed in more detail in section VIII.E, commenters, particularly states, provided compelling information establishing that for some, and perhaps many, states it will take longer than the agency initially anticipated to develop and submit their required plans. In response to those comments, we are finalizing a plan submittal process that provides additional time for states that need it to submit a final plan submittal to the EPA after September 6, 2016. Within the time period specified in the emission guidelines (from as early as September 6, 2016, to as late as September 6, 2018, depending on whether the state receives an extension), the state must submit its final state plan to the EPA. The EPA then must determine whether to approve or disapprove the plan. If a state does not submit a plan, or if the EPA disapproves a state's plan, then the EPA has the express authority under CAA section 111(d) to establish a federal plan for the state.[769] During and following implementation of its approved state plan, each state must demonstrate to the EPA that its affected EGUs are meeting the interim and final performance requirements included in this final rule through monitoring and reporting requirements.

This section is organized as follows. First, we discuss the timeline for state plan performance and provisions to encourage early action. Second, we describe the types of plans that states can submit. Third, we summarize the components of an approvable state plan submittal. Fourth, we address the process and timing for submittal of state plans and plan revisions. Fifth, we address plan implementation and achievement of CO_2 emission performance rates or state CO_2 emission goals for affected EGUs, and the consequences if they are not met. Sixth, we discuss general considerations for states in developing and implementing plans, including consideration of a facility's ''remaining useful life'' and ''other factors'' and electric reliability. Seventh, we note certain resources that are available to facilitate state plan development and implementation. Finally, we discuss additional considerations for inclusion of CO_2 emission reduction measures in state plans, including: Accounting for emission reduction measures in state plans; requirements for mass-based and rate-based emission trading approaches; EM&V requirements for RE and demand-side EE resources and other measures used to adjust a CO_2 rate; and treatment of interstate effects.

B. Timeline for State Plan Performance and Provisions To Encourage Early Action

This section describes state plan requirements related to the timing of achieving the emission reductions required in the guidelines and the state plan performance periods. This section also describes the CEIP the EPA is establishing to encourage early investment in certain types of RE projects, as well as in demand-side EE projects implemented in low-income communities.

1. Timeline for State Plan Performance

The final guidelines establish three types of performance periods: (1) A final deadline by which and after which affected EGUs must be in compliance with the final reduction requirements, (2) an interim period, and (3) within that interim period, three multi-year interim step periods. As discussed below and in section V, these performance periods are consistent with our determination of the BSER and are also responsive to the key comments we received on this aspect of the state plans.

A performance period is a period for which the final plan submittal must demonstrate that the required CO_2 emission performance rates or state CO_2 emission goal will be met. The final guidelines establish 2030 as the deadline for compliance by affected EGUs with the final CO_2 emission performance rates or CO_2 rate or mass emission goal; 2030 is the beginning of the final performance period. The interim performance period is 2022 to 2029, and there are three interim step periods—2022–2024, 2025–2027, and 2028–2029—where increasingly stringent emission performance rates or state emission goals must be met. The state may submit a plan that incorporates alternative interim step emission performance rates or state emission goals to those provided by EPA, as long as on average or cumulatively, as appropriate, they result in the equivalent of the interim emission performance rates or state emission goals in the emission guidelines. These timelines are based on careful consideration of the substantial comments we received on both the timing of the interim period and the trajectory of compliance by affected EGUs over the interim period and our determination of the BSER, discussed in section V above. The modifications we have made to the timelines included in the proposal respond to these comments and to concerns about, among other things, reliability, feasibility, and cost.

As previously discussed, the EPA has determined that the BSER includes implementation of reduction measures over the period of 2022 through 2029, with final compliance by affected EGUs in 2030. Therefore, the final rule requires that interim CO_2 emission performance rates or state CO_2 emission goals be met for the interim period of 2022–2029. Many commenters expressed a desire that the EPA designate steps during the interim period to create an interim goal that offered states and utilities greater flexibility and choice in determining their own emission reduction trajectories over the course of the interim period. Since our intent at proposal was to provide such flexibility and choice, and since it remains our intent to do so in this final rule, we are addressing these comments by including in the 2022–2029 interim period three interim step periods (2022–2024, 2025–2027, 2028–2029), which correspond roughly to the phasing in of the BSER. We note, however, that the final rule also allows states the flexibility to define an alternate trajectory of emission performance between 2022 and 2029, provided that (1) the state plan specifies its own interim step CO_2 emission performance rates or state CO_2 emission goals, (2) meeting the alternative interim step CO_2 emission performance rates or state CO_2 emission goals will result in the interim emission performance rates or state CO_2 emission goal being met on an 8-year average or cumulative basis, and, (3) the final CO_2 emission performance rates or state CO_2 emission goal is achieved. To be approvable, a state plan submittal must demonstrate that the emission performance of affected EGUs will meet the interim step CO_2 emission performance rates or interim step state CO_2 emission goals over the 2022–2024, 2025–2027, and 2028–2029 periods and the final CO_2 emission performance rates or state CO_2 emission goal no later than 2030.[770]

This relatively long period—first for planning, then for implementation and achievement of the interim and final CO_2 emission performance rates or state CO_2 emission goals—provides states and

[769] A federal plan may be withdrawn if the state submits, and the EPA approves, a state plan that meets the requirements of this final rule and section 111(d) of the CAA. More details regarding the federal plan are addressed in the EPA's proposed federal plan rulemaking.

[770] States are free to establish different interim step performance rates or interim step state goals than those the EPA has specified in this final rule. If states choose to determine their own interim step performance rates or state goals, the state must demonstrate that the plan will still meet the interim performance rates or state goal for 2022–2029 finalized in this action.

utilities with substantial flexibility regarding methods and timing of achieving emission reductions from affected EGUs. The EPA believes that timing flexibility in implementing measures provides significant benefits that allow states to develop plans that will help achieve a number of goals, including, but not limited to: Reducing cost, addressing reliability concerns, addressing concerns about stranded assets, and facilitating the integration of meeting the emission guidelines and compliance by affected EGUs with other air quality and pollution control obligations on the part of both states and affected EGUs. Moreover, we note that over the course of time between submittal of final plans and 2030, circumstances may change such that states may need or wish to modify their plans. The relatively lengthy performance periods provided in the final rule should help keep those situations to a minimum but will also accommodate them if necessary.[771] The EPA envisions that the agency, states and affected EGUs will have an ongoing relationship in the course of implementing this program. Since the record also indicates a high degree of interest on the part of states and stakeholders in pursuing banking and trading programs, the timing and level of stringency of the interim CO_2 performance rates or state CO_2 emission goals we are finalizing should provide states and affected EGUs with ample capacity to accommodate such changes without necessitating changes in state plans in many instances.

The timelines established in the final rule respond to the issues raised in numerous comments regarding the concept of the interim period, including comments supporting the flexibility afforded states in developing their plans and the timing necessary to meet the 2030 emission requirements. Some commenters supported beginning the interim goal plan period at 2020. Others stated that the investments necessary to meet the proposed interim emission performance goals beginning in 2020 are unachievable in that timeframe or would place too great a burden on affected EGUs, states, and ratepayers. Some suggested that the 2020 interim goal step should be eliminated in favor of later start dates, including 2022, 2025, or other years. Some commenters urged the EPA to establish phased interim steps creating a steady downward trajectory that allowed several years for each step, compatible with the ''chunkiness'' of utility planning processes. Yet other commenters provided input suggesting that states be allowed to establish their own set of emission performance steps during the interim plan performance period and thereby control their own emission reduction trajectory or ''glide path'' for achievement of the interim goal and the 2030 goal, or that the EPA not establish any interim standards at all. Commenters also noted that for some states, there was not a significant difference between the interim and final goal, and, therefore, no glide path for those states. As discussed in previous sections, based on this input and our final determination of the BSER, the EPA has adjusted the interim period to include 2022–2029, is establishing three interim performance periods creating a reasonable trajectory from 2022 to 2030, and is also retaining the flexibility for states to establish their own emission reduction trajectory during the interim period.

As noted, the EPA has determined that the period for mandated reductions should begin in 2022, instead of 2020 as we proposed, because of the substantial amount of comment and data we received indicating that states and utilities reasonably needed that additional time to take the steps necessary to start achieving reductions. In order to assure the EPA and the public that states are making progress in implementing the plan between the time of the state plan submittal and the beginning of the interim period, and as discussed in further detail in section VIII.D, the final rule requires that the state plan submittal include a timeline with all the programmatic plan milestone steps the state will take between the time of the state plan submittal and 2022 to ensure the plan is effective as of 2022.

2. Provisions To Encourage Early Action

Many commenters supported providing incentives for states and utilities to deploy CO_2-reducing investments, such as RE and demand-side EE measures, as early as possible. In the proposal, the EPA requested comment on an approach that would recognize emission reductions that existing programs provide prior to the initial plan performance period starting from a specified date. We also requested comment on options for that specified date and on conditions that should apply to counting those pre-compliance emission reductions toward a state goal. The EPA received many comments requesting that the agency recognize early actions for the emission reductions they provide prior to the performance period, that the EPA allow those pre-compliance impacts to be counted toward meeting requirements under the rule, and that certain conditions should be applied to recognition of early reductions so as to ensure the emission reductions required in the rule. We also received comments from stakeholders regarding the disproportionate burdens that some communities already bear, and stating that all communities should have equal access to the benefits of clean and affordable energy. The EPA recognizes the validity and importance of these perspectives, and as a result has determined to provide a program—called the Clean Energy Incentive Program (CEIP)—in which states may choose to participate. This section describes this program.

The CEIP is designed to incentivize investment in certain RE and demand-side EE projects that commence construction in the case of RE, or commence operation in the case of EE, following the submission of a final state plan to the EPA, or after September 6, 2018, for states that choose not to submit a final state plan by that date, and that generate MWh (RE) or reduce end-use energy demand (EE) during 2020 and/or 2021. State participation in the program is optional; the EPA is establishing this program as an additional flexibility to facilitate achievement of the CO_2 emission reductions required by this final rule, regardless of the type of state plan a state chooses to implement.

Under the CEIP, a state may set aside allowances from the CO_2 emission budget it establishes for the interim plan performance period or may generate early action ERCs (ERCs are discussed in more detail in section VIII.K.2), and allocate these allowances or ERCs to eligible projects for the MWh those projects generate or the end-use energy savings they achieve in 2020 and/or 2021. A state implementing a mass-based plan approach, as described in section VIII.C, may issue early action allowances; a state implementing a rate-based plan approach, also described in section VIII.C, may issue early action ERCs. For each early action allowance or ERC a state allocates to such projects, the EPA will provide the state with an appropriate number of matching allowances or ERCs, as outlined below, for the state to allocate to the project. The EPA will match state-issued early action ERCs and allowances up to an amount that represents the equivalent of 300 million short tons of CO_2 emissions. The EPA intends that a portion of this pool will be reserved for eligible wind and solar projects, and a portion will be reserved for low-income EE projects. In the proposed federal plan, the EPA is

[771] Modifications to state plans are addressed more specifically in section VIII.E.7 below.

taking comment on the size of each reserve, and is proposing provisions to provide that any unallocated amounts would be redistributed among participating states.

The EPA has determined that the size of this 300 million short ton CO_2-equivalent matching pool is an appropriate reflection of the CO_2 emission reductions that could be achieved by the additional early investment in RE and demand-side EE the agency expects will be incentivized by the CEIP. For example, in 2012, 13 GW of utility scale wind were deployed,[772] and, in 2014, 3.4 GW of utility-scale solar[773] plus 2–3 GW of distributed solar were deployed,[774] according to industry estimates. Assuming 19 GW per year of RE from 2017–2020 based on these historic maximums yields an installed base of 76 GW of RE potentially eligible for CEIP incentives in 2020 and/or 2021. Assuming an average capacity factor of 30 percent, this would translate into approximately 200 TWh/year of generation, which would be eligible for approximately 300 million short tons of matching allowances over the 2-year period, if the RE MWh were converted to allowances based on the 2012 carbon intensity of 0.8 short tons per MWh. This would leave the remaining half of the pool of matching federal allowances available for EE projects implemented in low-income communities, and additional growth in RE deployment beyond these historic maximums as potentially enabled by reductions in cost and improvements in performance.

For a state to be eligible for a matching award of allowances or ERCs from the EPA, it must demonstrate that it will award allowances or ERCs only to eligible projects. These are projects that:

- Are located in or benefit a state that has submitted a final state plan that includes requirements establishing its participation in the CEIP;
- Are implemented following the submission of a final state plan to the EPA, or after September 6, 2018, for a state that chooses not to submit a complete state plan by that date;
- For RE: Generate metered MWh from any type of wind or solar resources;
- For EE: Result in quantified and verified electricity savings (MWh) through demand-side EE implemented in low-income communities; and
- Generate or save MWh in 2020 and/or 2021.

The following provisions outline how a state may award early action ERCs or allowances to eligible projects, and how the EPA will provide matching ERCs or allowances to states.

- For RE projects that generate metered MWh from any type of wind or solar resources: For every two MWh generated, the project will receive one early action ERC (or the equivalent number of allowances) from the state, and the EPA will provide one matching ERC (or the equivalent number of allowances) to the state to award to the project.
- For EE projects implemented in low-income communities: For every two MWh in end-use demand savings achieved, the project will receive two early action ERCs (or the equivalent number of allowances) from the state, and the EPA will provide two matching ERCs (or the equivalent number of allowances) to the state to award to the project.

Early action allowances or ERCs awarded by the state, and matching allowances or ERCs awarded by the EPA pursuant to the CEIP, may be used for compliance by an affected EGU with its emission standards and are fully transferrable prior to such use.

The EPA discusses the CEIP in the proposed federal plan rule, and will address design and implementation details of the CEIP, including the appropriate factor for determining equivalence between allowances and MWh and the definition of a low-income community for project eligibility purposes, in a subsequent action. Before doing so, the EPA will engage states and stakeholders to gather additional information concerning implementation topics, and to solicit information about the concerns, interests and priorities of states, stakeholders and the public.

In order for a state that chooses to participate in the CEIP to be eligible for a future award of allowances or ERCs from the EPA, a state must include in its initial submittal a non-binding statement of intent to participate in the program. In the case of a state submitting a final plan by September 6, 2016, the state plan would either include requirements establishing the necessary infrastructure to implement such a program and authorizing its affected EGUs to use early action allowances or ERCs as appropriate, or would include a non-binding statement of intent as part of its supporting documentation and revise its plan to include those requirements at a later date.

Following approval of a final state plan that includes requirements for implementing the CEIP, the agency will create an account of matching allowances or ERCs for the state that reflects the pro rata share—based on the amount of the reductions from 2012 levels the affected EGUs in the state are required to achieve relative to those in the other participating states—of the 300 million short ton CO_2 emissions-equivalent matching pool that the state is eligible to receive. Thus, states whose EGUs have greater reduction obligations will be eligible to secure a larger proportion of the federal matching pool upon demonstration of quantified and verified MWh of RE generation or demand side-EE savings from eligible projects realized in 2020 and/or 2021.

Any matching allowances or ERCs that remain undistributed after September 6, 2018,[775] will be distributed to those states with approved state plans that include requirements for CEIP participation. These ERCs and allowances will be distributed according to the pro rata method outlined above. Unused matching allowances or ERCs that remain in the accounts of states participating in the CEIP on January 1, 2023, will be retired by the EPA.

For purposes of establishing a state plan program eligible for an award of matching allowances or ERCs from the EPA, such a program must include a mechanism for awarding early action emission allowances or ERCs for eligible actions that reduce or avoid CO_2 emissions in 2020 and/or 2021, and that is implemented in a way such that the early action allowances or ERCs allocated by the state would maintain the stringency of the state's goal for emission performance from affected EGUs in the performance periods established in this rule. Specifically, the state must demonstrate in its plan that it has a mechanism in place that enables issuance of ERCs or allowances from the state to parties effectuating reductions in 2020 and/or 2021 in a manner that would have no impact on the aggregate emission performance of affected EGUs required to meet rate-based or mass-based CO_2 emission standards during

[772] U.S. Energy Information Administration Electric Power Annual 2013. *http://www.eia.gov/electricity/annual*. Table 4.6: Capacity additions, retirements and changes by energy source. March 2015.

[773] U.S. Energy Information Administration Electric Power Monthly. *http://www.eia.gov/electricity/monthly*. Table 6.3: New Utility Scale Generating Units by Operating Company, Plant, Month, and Year.

[774] GTM Research/Solar Energy Industries Association: U.S. Solar Market Insight Q1 2015.

[775] This may occur because not all states may elect to include requirements for CEIP participation in their state plans.

the compliance periods.[776] This demonstration is not required to account for matching ERCs or allowances that may be issued to the state by the EPA. Participation in this program is entirely voluntary, and nothing in these provisions would have the effect of requiring any particular affected EGU to achieve reductions prior to 2022, or requiring states to offer incentives for emission reductions achieved prior to 2022.[777] These and other details will be developed in the subsequent action.

The EPA is providing the CEIP as an option for states implementing plans—and is including a similar program for the federal plan proposal being issued concurrently—for several reasons. Chief among them is that offered by commenters to the effect that the overall cost of achievement of the emission performance rates or state goals could be reduced by an approach that granted some form of beneficial recognition to emissions reduction investments that both occur and yield reductions prior to the first date on which the program of the interim plan performance period. Other commenters pointed out that to the extent that states and utilities would benefit from the availability of low-cost RE and other zero-emitting generation options during the interim and final plan performance periods, the EPA should include in the final emission guidelines provisions that accelerate deployment of RE resources, since in so doing the final emission guidelines would speed achievement of expected reductions in the cost of those technologies commensurate with their accelerated deployment. In addition, the incentives and market signal generated by the CEIP can help sustain the momentum toward greater RE investment in the period between now and 2022 so as to offset any dampening effects that might be created by setting the start date 2 years later than at proposal.

The specific criteria the EPA is establishing for eligible RE projects reflect a variety of considerations. First, the EPA seeks to preserve the incentive for project developers to execute on planned investments in all types of solar and wind technologies. Commenters raised concerns that the fast pace of reductions underlying the emission targets in the proposed rule could potentially shift investment from RE to natural gas, thus dampening the incentive to develop wind and solar projects, in particular. Second, the EPA, consistent with the CAA's design that incentivizes technology and accelerates the decline in the costs of technology, seeks to drive the widespread development and deployment of wind and solar, as these broad categories of renewable technology are essential to longer term climate strategies. Finally, in contrast to other CO_2-reducing technologies—including other zero-emitting or RE technologies—solar and wind projects often require lead times of shorter duration, which would allow them to generate MWh beginning in 2020.

The specific criterion the EPA is establishing for eligible EE projects—namely that these projects be implemented in low-income communities—is also consistent with the technology-forcing and development design of CAA section 111. The EPA believes it is appropriate to offer an additional incentive to remove current barriers to implementing demand-side EE programs in low-income communities. While the EPA acknowledges that a number of states have demand-side EE programs focused on these communities,[778] the agency also recognizes that there have been historic economic, logistical, and information barriers to implementing programs in these communities. As a result, the costs of implementing demand-side EE programs in these communities are typically higher than in other communities and stand as barrier to harvesting potentially cost effective reductions and advancing these technologies. The EPA intends for the CEIP to help incentivize increased deployment of projects that will deliver demand-side EE benefits to these communities, which will in turn lower the costs of these approaches. These lower costs will help new technologies and delivery mechanisms penetrate in the future, thus improving the cost of implementation of the emission guidelines overall, consistent with Congress' design in the New Source Performance Standard provisions of the CAA. Further, reducing barriers to demand-side EE in low-income communities will help ensure that the benefits of the final rule are shared broadly across society and that potential adverse impacts on low-income ratepayers are avoided. It complements other steps the federal government is taking to bring clean energy technologies to these communities, as we discuss in section IX of this preamble.

More broadly, the CEIP responds to the urgency of meeting the challenge of climate change in two key ways. First, of course, it fosters reductions before 2022. Second, in targeting investments in wind, solar and low-income EE, it focuses on the kinds of measures and technologies that are the essential foundation of longer-term climate strategies, strategies that inevitably depend on the further development and widespread deployment of highly adaptable zero-emitting technologies.

We are not requiring that projects demonstrate to states that they are ''additional'' or surplus relative to a business-as-usual or state goal-related baseline in order to be eligible. At the same time, we believe that including an incentive to develop projects that benefit low-income communities will increase the likelihood of investments being made that would not have been made otherwise.

In order to be awarded matching ERCs or allowances by the EPA for projects that meet the eligibility criteria, a final state plan must have requirements establishing the appropriate infrastructure to issue early action ERCs or allowances to eligible project providers by 2020. The state must require that the state or its agent will, in accordance with state plan requirements approved as meeting the ERC issuance and EM&V requirements included in section VIII.K: (1) Evaluate project proposals from eligible RE and demand-side EE project providers, including the EM&V plans that must accompany such proposals; (2) evaluate monitoring and verification reports submitted by eligible providers following project implementation, which contain the quantified and verified MWh of RE generation or energy savings achieved

[776] For example, under a mass-based implementation, the state plan could include a set-aside of early action allowances from an emissions budget that itself reflects the state goals. Allocation of those early action allowances to parties effectuating reductions in 2020 and 2021 would have no impact on the total emissions budget, which sets the total allowable emissions in the compliance periods. Alternatively, under a rate-based implementation, the state plan could require that early action ERCs issued to parties effectuating reductions in 2020 and 2021 would be ''borrowed'' from a pool of ERCs created by the state during the interim plan performance period. States could limit the size of the ''borrowed'' pool of ERCs to be equivalent to the size of the federal matching pool, or could take into consideration the potential for each state's federal matching pool to expand after a redistribution of unused credits. For every early action ERC awarded for actions in 2020 and 2021, the state would retire one ERC from the pool of ERCs created as a result of reductions achieved from 2022 onward.

[777] In addition to the CEIP, states may also offer credit for early investments in RE and demand-side EE according to the provisions of section VIII.K.1 of this final rule: A state may award ERCs to qualified providers that implement projects from 2013 onward that realize quantified and verified MWh results in 2022 and subsequent years.

[778] Several of these programs are discussed in section IX of this preamble, including, for example, Maryland's EmPOWER Low Income Energy Efficiency Program (LIEEP) and New York's EmPower New York program.

by the project in 2020 and/or 2021; (3) issue ERCs or allowances to eligible providers for these MWh results; (4) ensure that no MWh of renewable generation or energy savings receives early action or matching ERCs or allowances more than once.[779]

The CEIP will provide a number of benefits. First, the program will provide incentives designed to reduce energy bills early in the implementation of the guidelines through earlier and broader application of energy saving technologies, and help ensure that these benefits are fully shared by low-income communities. Second, the EPA believes that stimulating or supporting early investment in RE generation technologies could accelerate the rate at which the costs of these technologies fall over the course of the interim performance period. Third, the CEIP will provide affected EGUs and states with additional emission reduction resources to help them achieve their state plan obligations. Finally, the program will improve the liquidity, in the early years of the program, of the ERC and allowance markets we expect to emerge for compliance with the requirements of these guidelines.[780]

The EPA is establishing this program as an option for states that wish to drive investments in RE and low-income EE that will result in actual, early reductions in CO_2 emissions from affected EGUs. States are also authorized to set their own glide path, or interim step performance rates or goals, so long as the interim and final performance rates or goals are met, and could do so in a way that takes into account the availability of the CEIP to assist affected EGUs in meeting the applicable glide path and performance rates or goals. While the EPA is not requiring states to take advantage of this program, its availability simply enhances these already-existing implementation and compliance flexibilities while at the same time delivering meaningful benefits, particularly for low-income communities. The EPA looks forward to an upcoming public dialogue about the implementation details of the CEIP.

C. State Plan Approaches

1. Overview

Under the final emission guidelines, states may adopt and submit either of two different types of state plans. The first would apply all requirements for meeting the emission guidelines to affected EGUs in the form of federally enforceable emission standards.[781] We refer to this as an ''emission standards'' state plan type. The second, which we refer to as a ''state measures'' plan type, would allow the state mass CO_2 emission goals to be achieved by affected EGUs in part, or entirely, through state measures [782] that apply to affected EGUs, other entities, or some combination thereof. The state measures plan type also includes a mandatory contingent backstop of federally enforceable emission standards for affected EGUs that would apply in the event the plan does not achieve its anticipated level of emission performance as specified in the state plan during the period that the state is relying on state measures. The inclusion of a backstop of federally enforceable emission standards in a state measures plan type is legally necessary for a state plan to meet the terms of 111(d), which specifically require a state to submit standards of performance.

These two types of state plans and their respective approaches, either of which could be implemented on a single-state or multi-state basis, allow states to meet the statutory requirements of CAA section 111(d) while accommodating the wide range of regulatory requirements and other programs that states have deployed or will deploy in the electricity sector that reduce CO_2 emissions from affected EGUs. Further, as described in detail below, both types of plans are responsive to comments we received from states and other stakeholders. In addition to providing states the option of developing an emission standards or state measures type plan, the final rule makes clear that states that choose an emission standards plan can adopt a plan that meets either the CO_2 emission performance rates, a rate-based CO_2 emission goal, or a mass-based CO_2 emission goal.

Under these two basic plan types, the final emission guidelines provide states with a number of potential plan pathways for meeting the emission guidelines. A plan pathway represents a specific plan design approach used to meet the emission guidelines. These plan pathways are discussed in section VIII.C.2 through C.5 below, and further elaborated in sections VIII.J (for mass-based emission standards) and VIII.K (for rate-based emission standards).

The final emission guidelines provide four streamlined plan pathways. These streamlined plan pathways represent straightforward plan approaches for meeting the emission guidelines, and avoid the need to meet additional plan requirements and include additional elements in a plan submittal. The streamlined plan pathways include the following:

- Establishing federally enforceable, mass-based CO_2 emission standards for affected EGUs, complemented by state-enforceable mass-based CO_2 emission standards for new fossil fuel-fired EGUs.[783] This approach could involve an emission budget trading program that includes affected EGUs as well

[779] For a state plan incorporating the use of ERCs or allowances to be approvable by the EPA, such a plan must use an EPA-approved or EPA-administered tracking system for ERCs or allowances. The EPA received a number of comments from states and stakeholders about the value of the EPA's support in developing and/or administering tracking systems to support state administration of rate-based emission trading programs. The EPA is exploring options for providing such support and is conducting an initial scoping assessment of tracking system support needs and functionality.

[780] The CEIP is expected to provide states and affected EGUs additional flexibility in meeting the guidelines, and bears similarity in both design and purpose to the Compliance Supplement Pool, which the agency established as a part of the NO_X SIP Call. *See* 63 FR 57356, 57428–30 (Oct. 27, 1998). Certain aspects of the Compliance Supplement Pool were challenged in litigation and upheld by the D.C. Circuit Court of Appeals. *See Michigan* v. *EPA,* 213 F.3d 663, 694 (D.C. Cir. 2000).

[781] 40 CFR 60.21(f) defines ''emission standard'' as ''a legally enforceable regulation setting forth an allowable rate of emissions into the atmosphere, establishing an allowance system, or prescribing equipment specifications for control of air pollution emissions.'' This definition is promulgated and effective, and we note that it authorizes the use of allowance systems as a form of emission standard. To resolve any doubt that allowance systems are an acceptable form of emission standard in the final rule, we are including regulatory text in the final subpart UUUU regulations authorizing the use of allowance systems as a form of emission standard under section 111(d). Section 60.21(f) was originally amended in 2005 to include recognition of allowance systems as a form of emission standard in the Clean Air Mercury Rule (CAMR) (70 FR 28606, 28649; May 18, 2005). CAMR was vacated in its entirety in *New Jersey* v. *EPA,* 517 F.3d 574 (D.C. Cir. 2008). However, the reason for vacatur was wholly unrelated to the question of whether an allowance system could be a form of emission standard. In response to the *New Jersey* decision, the agency removed CAMR provisions from the Code of Federal Regulations. The agency chose to retain the language of 60.21(f) and 60.24(b)(1) generally recognizing allowance systems. This language is broader than CAMR and unrelated to the reasons for its vacatur. The EPA re-promulgated these provisions in February of 2012 (77 FR 9304, 9447; Feb. 16, 2012). Even if this were not the case, the agency would not concede that simply because ''allowance systems'' were not provided for in the framework regulations of subpart B, they could not be relied upon in specific emission guidelines, such as these for CO_2. The implementing regulations generally serve a gap-filling role where there are not more specific provisions laid out in the relevant emission guidelines. In order to resolve any question whether allowance systems are authorized under the final rule, we are including regulatory text in subpart UUUU to make this authorization explicit.

[782] ''State measures'' refer to measures that are adopted, implemented, and enforced as a matter of state law. Such measures are enforceable only per state law, and are not included in and codified as part of the federally enforceable state plan.

[783] New source CO_2 emission complements are discussed in section VIII.J.2.b, which also provides EPA-derived new source CO_2 emission complements for states.

as new fossil fuel-fired EGUs. This approach facilitates interstate emission trading, through either a single-state ''ready-for-interstate-trading'' plan approach or through a multi-state plan. Under a ''ready-for-interstate-trading'' plan, interstate emission trading may occur without the need for a multi-state plan.[784]

- Establishing federally enforceable, mass-based CO_2 emission standards for affected EGUs.[785] This approach facilitates interstate emission trading, through either a single-state ''ready-for-interstate-trading'' plan approach or through a multi-state plan. In a separate concurrent action, the EPA is proposing a model rule for states that could be used in a plan implementing this approach.[786]
- Establishing federally enforceable, subcategory-specific rate-based CO_2 emission standards for affected EGUs, consistent with the CO_2 emission performance rates in the emission guidelines. This approach provides for interstate emission trading, through either a single-state ''ready-for-interstate-trading'' plan approach or through a multi-state plan.[787] In a separate concurrent action, the EPA is proposing a model rule for states that could be used in a plan implementing this approach.
- Establishing federally enforceable rate-based CO_2 emission standards at a single level that applies for all affected EGUs, consistent with the state rate-based CO_2 goal for affected EGUs in the emission guidelines.[788] This approach provides for interstate emission trading, through a multi-state plan that meets a single weighted average multi-state rate-based CO_2 goal.[789]

The final emission guidelines also provide for a range of additional custom plan approaches that a state may pursue, if it chooses, to address specific circumstances or policy objectives in a state. The custom plan pathways, while viable options for meeting the emission guidelines, come with additional plan requirements and plan submittal elements. These additional plan requirements and plan submittal elements are necessary to ensure that the emission guidelines are met and that the necessary level of CO_2 emission performance is achieved by affected EGUs.

Based on this overall approach, the final emission guidelines provide for a range of state options—both easily implementable approaches that can be used to meet the emission guidelines, and more customizable approaches that can be used, if a state chooses, to address special circumstances or state policy objectives.

2. ''Emission Standards'' State Plan Type

The emission standards type of state plan imposes requirements solely on affected EGUs in the form of federally enforceable emission standards. This type of state plan, as described below, may consist of rate-based emission standards for affected EGUs or mass-based emission standards for affected EGUs.

The state plan submittal for an emission standards type plan must demonstrate that these federally enforceable emission standards for affected EGUs will achieve the CO_2 emission performance rates or the applicable state rate-based or mass-based CO_2 emission goal for affected EGUs.

Both rate-based and mass-based emission standards included in a state plan must be quantifiable, verifiable, enforceable, non-duplicative and permanent. These requirements are described in more detail at section VIII.D.2.

Rate-based and mass-based emission standards may incorporate the use of emission trading, as described below. The EPA anticipates the use of emission trading in state plans, given the advantages of this approach and comments suggesting a high degree of interest on the part of states, utilities, and independent power producers in the inclusion of emission trading in state plans.[790]

The EPA notes it is proposing model rules for both mass-based and rate-based emission trading programs. States could adopt and submit the finalized model rules for either emission trading program to meet the requirements of CAA section 111(d) and these emission guidelines. The EPA will evaluate the approvability of such submission, as with any state plan submission, through independent notice-and-comment rulemaking. The EPA notes that state plan submittals that adopt the finalized model rule may be administratively and technically more straightforward for the EPA in evaluating approvability, as the EPA will have determined that the model rule meets the applicable requirements of the emission guidelines through the process of finalization of such rule.

a. *Rate-based approach.* The first type of ''emission standards'' plan approach a state may choose is one that uses rate-based emission standards. Under this plan approach, the plan would include federally enforceable emission standards for affected EGUs, in the form of lb CO_2/MWh emission standards.

A rate-based ''emission standards'' plan may be designed to either meet the CO_2 emission performance rates for affected EGUs or achieve the state's rate-based CO_2 emission goal for affected EGUs. A plan could be designed such that compliance by affected EGUs would assure achievement of either the CO_2 emission performance rates for affected EGUs or the state rate-based CO_2 emission goal. To meet the CO_2 emission performance rates for affected EGUs, a plan would establish separate rate-based emission standards for affected fossil fuel-fired electric utility steam generating units and stationary combustion turbines (in lb CO_2/MWh) that are equal to or lower than the CO_2 emission performance rates in the emission guidelines. To meet a state rate-based CO_2 goal, a plan would establish a uniform rate-based emission standard (in lb CO_2/MWh) that applies to all affected EGUs in the state. This uniform emission rate would be equal to or lower than the applicable state rate-based CO_2 goal specified in the final emission guidelines.

Under these two approaches, compliance by affected EGUs with the rate-based emission standards in a plan would ensure that affected EGUs meet the CO_2 emission performance rates in the emission guidelines or the state rate-based CO_2 goal for affected EGUs. No further demonstration would be necessary by the state to demonstrate that its plan would achieve the CO_2 emission performance rates or the state's rate-based CO_2 goal.

Alternatively, if a state chooses, it could apply rate-based emission standards to individual affected EGUs, or to categories of affected EGUs, at a lb CO_2/MWh rate that differs from the CO_2 emission performance rates or the state's rate-based CO_2 goal. In this case, compliance by affected EGUs with their emission standards would not necessarily ensure that the collective, weighted average CO_2 emission rate for these affected EGUs meets the CO_2 emission performance rates or the state's rate-based CO_2 goal.[791]

[784] Mass-based trading-ready plans are addressed in section VIII.J.3. Multi-state plans, where a group of states are meeting a joint CO_2 goal for affected EGUs, are addressed in section VIII.C.5.

[785] This plan approach would meet a state mass-based CO_2 goal for affected EGUs, or a joint multi-state mass-based CO_2 goal for affected EGUs. These plan approaches are discussed in sections VIII.J.2 and VIII.C.5, respectively.

[786] Submission of a state plan based on the EPA's finalized model rule for a mass-based emission trading program could be considered presumptively approvable. The EPA would evaluate the approvability of such submission through an independent notice and comment rulemaking.

[787] Rate-based trading-ready plans are addressed in section VIII.K.4.

[788] This plan approach is addressed in section VIII.C.2.a.

[789] This multi-state plan approach is addressed in section VIII.C.5.

[790] The legal basis for authorizing trading in emission standards is discussed in section VIII.C.6.

[791] The weighted average CO_2 emission rate that will be achieved by the fleet of affected EGUs in a

Continued

Under this type of approach, therefore, the state would be required to include a demonstration,[792] in the state plan submittal, that its plan would achieve the CO_2 emission performance rates or applicable state rate-based CO_2 goal. This demonstration would include a projection of the collective, weighted average CO_2 emission rate the fleet of affected EGUs would achieve as a result of compliance with the emission standards in the plan. Once the plan is implemented, if the CO_2 emission performance rates or applicable state rate-based CO_2 goal are not achieved, corrective measures would need to be implemented, as described in section VIII.F.3.

Under a rate-based approach, a state may include in its plan a number of provisions to facilitate affected EGU compliance with the emission standards. First, a state may encourage (or require) EGUs to undertake actions to reduce CO_2 emissions at the affected EGU level, such as heat rate improvements or fuel switching. These measures are discussed in section VIII.I. Second, a state may implement a market-based emission trading program, which enables EGUs to generate and procure ERCs, a tradable compliance unit representing one MWh of electric generation (or reduced electricity use) with zero associated CO_2 emissions. Considerations and requirements for rate-based trading programs are discussed in section VIII.K.

ERCs would be issued by the administering state regulatory body. The state may issue ERCs to affected EGUs that emit below a specified CO_2 emission rate, as well as for measures that provide substitute generation for affected EGUs or avoid the need for generation from affected EGUs. These ERCs may then be used to adjust the reported CO_2 emission rate of an affected EGU when demonstrating compliance with a rate-based emission standard. For each submitted ERC, one MWh is added to the denominator of the reported CO_2 emission rate, resulting in a lower adjusted CO_2 emission rate.

Eligible measures that may generate ERCs, as well as the accounting method for adjusting a CO_2 emission rate, are discussed in section VIII.K.1. Requirements for rate-based emission trading approaches are discussed in section VIII.K.2. Quantification and verification requirements for measures eligible to generate ERCs are discussed in section VIII.K.3.

(1) *Rate-based emission standards based on operational or other standards.*

As discussed in further detail in section VIII.D.2.d.3, regarding the legal considerations and statutory language of CAA section 111(h), the EPA is finalizing that design, equipment, work practice, and operational standards cannot be considered to be ''standards of performance'' for this final rule. However, a state may elect to use emission standards for affected EGUs that result in a reduced CO_2 lb/MWh emission rate for affected EGUs because of operational or other standards. The state would include in its state plan an emission standard that is the rate standard that results from the applicable operational or other standard. For example, a state might choose to recognize that an individual affected EGU has plans to retire, and those plans could be codified in the state plan by adopting an emission standard of 0 CO_2 lb/MWh as of a certain date. The state would thus include in the state plan an emission standard of 0 CO_2 lb/MWh for that affected EGU that applies after a specified date.

An approvable plan could apply such emission standards to a subset of affected EGUs or all affected EGUs. As with any rate-based plan, the state would need to demonstrate that the plan would achieve the required level of emission performance for affected EGUs, in CO_2 lb/MWh. A plan could also apply such emission standards to a subset of affected EGUs in the state while applying other rate-based emission standards to the remainder of affected EGUs in the state. For example, a plan might include an emission standard of 0 CO_2 lb/MWh reflecting a retirement mandate for one or more affected EGUs in a state and apply a rate-based emission standard equal to the CO_2 emission performance rates or a state's rate-based CO_2 emission goal to the remainder of affected EGUs.

As with all emission standards, emission standards based on design, equipment, work practice, and operational standards must be quantifiable, verifiable, enforceable, non-duplicative and permanent. These requirements are described in more detail at section VIII.D.2.

(2) *Additional considerations for rate-based approach.*

Additional considerations and requirements for rate-based emission standards state plans are addressed in section VIII.K. This includes the basic accounting method for adjusting the reported CO_2 emission rate of an affected EGU, as well as requirements for the use of measures to adjust a CO_2 emission rate, both of which are discussed in sections VIII.K.1 through 3. Such requirements include eligibility, accounting, and quantification and verification requirements (EM&V) for the use of CO_2 emission reduction measures that provide substitute generation for affected EGUs or avoid the need for generation from affected EGUs in rate-based state plans. Section VIII.K.4 addresses multi-state coordination among rate-based emission trading programs.

b. *Mass-based approach.*

The second ''emission standards'' approach a state may elect to use is mass-based emission standards applied to affected EGUs. Under this approach, the plan would include federally enforceable emission standards for mass CO_2 emissions from affected EGUs. The plan would be designed to achieve the mass-based CO_2 goal for a state's affected EGUs (see section VII) or a level of CO_2 emissions equal to or less than the mass-based CO_2 goal plus the new source complement CO_2 emissions (see section VIII.J.2.b, Table 14).[793]

Under a mass-based approach, a state could require that individual affected EGUs meet a specified mass emission standard. Alternatively, a state could choose to implement a market-based emission budget trading program. The EPA envisions that the latter option is most likely to be exercised by states seeking to implement a mass-based emission standard approach, as it would maximize compliance flexibility for affected EGUs and enable the state to meet its mass goal in the most economically efficient manner possible.

(1) *Mass-based emission standard applied to individual affected EGUs.*

One pathway a state could take to achieve its mass-based CO_2 goal would be to apply mass-based emission standards to individual affected EGUs, in the form of a limit on total allowable

state that applies different rate-based emission standards to individual affected EGUs or groups of affected EGUs will depend upon the mix of electric generation from affected EGUs subject to different emission standards. For example, if a state applies higher emission standards for affected steam generating units and lower emission standards for affected NGCC units, the greater the projected amount of electric generation from steam generating units, the higher the projected weighted average emission rate that will be achieved for all affected EGUs.

[792] A demonstration of how a plan will achieve a state's rate-based or mass-based CO_2 emission goal is one of the required plan components, as described in section VIII.D.2.

[793] For example, a state plan designed to meet a state mass-based CO_2 goal for affected EGUs plus a new source complement could involve a mass-based emission budget trading program that, under state law, applies to both affected EGUs, as well as new fossil fuel-fired EGUs. The program requirements for affected EGUs would be federally enforceable, while the program requirements for other fossil fuel-fired EGUs would be state-enforceable. This approach is described further in section VIII.J.2.

CO_2 emissions. These emission standards would be designed such that total allowable CO_2 emissions from all affected EGUs in a state are equal to or less than the state's mass-based CO_2 goal, or a state's mass-based CO_2 goal plus the new source complement CO_2 emissions specified in section VIII.J.2.b, Table 14. The individual affected EGUs would be required to emit at or below their mass-based standard to demonstrate compliance. Under this approach, individual affected EGUs would be required to undertake source-specific measures to assure their CO_2 emissions do not exceed their assigned emission standard. Affected EGU compliance with the emission standards prescribed under this type of mass-based approach would ensure that the affected EGUs in a state achieve the state's mass-based CO_2 goal, or mass-based CO_2 goal plus new source complement.

(2) *Mass-based emission standard with a market-based emission budget trading program.*

A second pathway a state could take to achieve its mass-based CO_2 goal would be to implement a market-based emission budget trading program. This type of program provides maximum compliance flexibility to affected EGUs, and as a result, may be attractive to states that choose to implement a mass-based approach in their state plan.

An emission budget trading program establishes a combined emission standard for a group of emission sources in the form of an emission budget. Emission allowances are issued in an amount up to the established emission budget.[794] Allowances may be distributed to affected emission sources (as well as to other parties) through a number of different methods, including direct allocation to affected sources or auction. These allowances can be traded among affected sources and other parties. The emission standard applied to individual emission sources is a requirement to surrender emission allowances equal to reported emissions, with each allowance representing one ton of CO_2.

The EPA views an emission budget trading program as a highly efficient, market-based approach for reducing CO_2 emissions from affected EGUs. Such programs include a limit on mass CO_2 emissions while providing both short-term and long-term price signals that encourage the owners or operators of affected EGUs, as well as other entities, to determine the most efficient means of achieving the mass emission standard. Notably, such an approach incentivizes actions taken at affected EGUs to reduce CO_2 emissions, as well as the use of strategies such as RE and demand-side EE as complementary measures that reduce CO_2 emissions. However, unlike under a rate-based approach, for this latter set of measures there is no need to address and describe these state measures in a state plan submission or quantify and verify the RE and EE MWh of generation and savings. As a result, a mass-based emission budget trading program incentivizes and recognizes a wide range of emission reduction actions while being relatively simple for a state to implement and administer. Furthermore, the EPA notes that such an approach still allows for a state to address electricity load growth, as load growth can be met through low- and zero-emitting generating resources, as well as avoided through demand-side EE and demand-side management (DSM) measures.

Additional considerations and requirements for mass-based emission standards state plans are addressed in section VIII.J. This includes use of emission budget trading programs in a state plan, including provisions required for such programs (section VIII.J.2.a) and the design of such programs in the context of a state plan. Section VIII.J addresses program design approaches that ensure achievement of a state mass-based CO_2 emission goal (section VIII.J.2.c), as well as how states can use emission budget trading programs with broader source coverage and other flexibility features in a state plan, such as the programs currently implemented by California and the RGGI participating states (section VIII.J.2.d). Section VIII.J.2.e addresses other considerations for the design of emission budget trading programs that states may want to consider, such as allowance allocation approaches. Section VIII.J.3 addresses multi-state coordination among emission budget trading programs used in states that retain their individual state mass-based CO_2 goals.

(3) *Mass-based emission standards based on operational or other standards.*

As discussed in section VIII.C.2.a.(1) above, a state may elect to use mass-based emission standards for affected EGUs that result in a reduced total tonnage of CO_2 emissions from affected EGUs because of operational or other standards. The state would include in its state plan an emission standard that is the mass standard that results from the applicable operational or other standard. For example, a state might choose to recognize that an individual affected EGU has plans to retire, and those plans could be codified in the state plan by adopting an emission standard of 0 total tons of CO_2, as of a certain date. The state would thus include in the state plan an emission standard of 0 total tons of CO_2 for that affected EGU that applies after a specified date. Under a mass-based approach, the state could also include an emission standard (*e.g.,* a mass limit) that reflects the result of a limit on an affected EGU's total operating hours over a specified period. Such an emission standard would be based on an affected EGU's potential to emit given a specified number of operating hours.

An approvable plan could apply such emission standards to a subset of affected EGUs or all affected EGUs. As with any mass-based plan, the state would need to demonstrate that the plan would achieve the required level of emission performance for affected EGUs, in total tons of CO_2. A plan could also apply such emission standards to a subset of affected EGUs in the state while applying other emission standards to the remainder of affected EGUs in the state. For example, a plan might include an emission standard of 0 tons of CO_2 for one or more affected EGUs, reflecting a retirement mandate for one or more affected EGUs in a state, and include the remainder of affected EGUs in an emission budget trading program.

3. ''State Measures'' State Plan Type

The second type of state plan is what we refer to as a ''state measures'' plan. As previously discussed, the EPA believes states will be able to submit state plans under the emission standards plan type, and its respective approaches, and achieve the CO_2 emission performance rates or state rate-based or mass-based CO_2 goals by imposing federally enforceable requirements on affected EGUs. Upon further consideration of the requirements of CAA section 111(d), in consideration of the comments we received on the proposed portfolio approach and the state commitments approach, and in order to provide flexibility and choice to states that may wish to adopt a plan that does not place all the obligations on affected EGUs, the EPA is finalizing the state measures plan type in addition to the emission standards plan type. The EPA believes the state measures plan type will provide states with additional latitude in accommodating existing or planned programs that involve measures implemented by the state, or by entities other than affected EGUs, that result in avoided generation and CO_2 emission

[794] An emission allowance represents a limited authorization to emit, typically denominated in one short ton or metric ton of emissions.

reductions at affected EGUs. This includes market-based emission budget trading programs that apply, in part, to affected EGUs, such as the programs implemented by California and the RGGI participating states in the Northeast and Mid-Atlantic, as well as RE and demand-side EE requirements and programs, such as renewable portfolio standards (RPS), EERS, and utility- and state-administered incentive programs for the deployment of RE and demand-side EE technologies and practices. The EPA believes this second state plan type will afford states with appropriate flexibility while meeting the statutory requirements of CAA section 111(d).

Measures implemented under the state measures plan type could include RE and demand-side EE requirements and deployment programs. This type of plan could align with existing state resource planning in the electricity sector, including RE and demand-side EE investments by state-regulated electric utilities. The state measures plan type also can accommodate emission budget trading programs that address a broader set of emission sources than just affected EGUs subject to CAA section 111(d), such as the programs currently implemented by California and the RGGI participating states. The EPA also notes that the state measures plan type could accommodate imposition by a state of a fee for CO_2 emissions from affected EGUs, an approach suggested by a number of commenters.

This plan type would allow the state to implement a suite of state measures that are adopted, implemented, and enforceable only under state law, and rely upon such measures in achieving the required level of CO_2 emission performance from affected EGUs. The state measures under this plan type could be measures involving entities other than affected EGUs, or a combination of such measures with emission standards for affected EGUs, so long as the state demonstrates that such measures will result in achievement of a state's mass-based CO_2 goal (or mass-based CO_2 goal plus new source complement), as discussed below. The EPA notes that under this plan type, a state could also choose to include any emission standards for affected EGUs, which are required to be included in the plan as federally enforceable measures, to be implemented alongside or in conjunction with state measures the state would implement and enforce.

For a state measures plan to be approvable, it must include a demonstration of how the measures, whether state measures alone or state measures in conjunction with any federally enforceable emission standards for affected EGUs, will achieve the state mass-based CO_2 emission goal for affected EGUs (or mass-based CO_2 goal plus new source complement). However, because the state measures would not be federally enforceable emission standards, the plan must also include a backstop of federally enforceable emission standards for all affected EGUs, in order for the state measures plan type to satisfy the requirement of CAA section 111(d) that a state establish standards of performance for affected EGUs. This backstop would impose federally enforceable emission standards on the state's affected EGUs in the case that the state measures fail to achieve the state mass-based CO_2 goal. The backstop, discussed further below, would assure that the state CO_2 emission goal or CO_2 emission performance rates are fully achieved by affected EGUs in the form of federally enforceable emission standards.

a. *Requirements for state measures under a state measures type plan.*

Under the state measures plan type, state measures must be satisfactorily described in the supporting material for a state plan submittal. The supporting material would need to demonstrate that the state measures meet the same integrity elements that would apply to federally enforceable emission standards. Specifically, the state plan submittal must demonstrate that the state measures are quantifiable, verifiable, enforceable, non-duplicative and permanent. These requirements are described in more detail at section VIII.D.2. Under the state measures plan, if a state chooses to impose emission standards on affected EGUs, such emission standards must be included in the federally enforceable plan as they would be under an emission standards plan.

The EPA would assess the overall approvability of a state measures plan based, in part, on the state's satisfactory demonstration that the state measures, in conjunction with any federally enforceable emission standards on the affected EGUs that might be included in the plan, would result in the state plan's achievement of the mass-based CO_2 goal for the state's affected EGUs (or mass-based CO_2 goal plus new source complement). This includes a demonstration of adequate legal authority and funding to implement the state plan and any associated measures. The EPA's determination that such a plan is satisfactory would be based in part on whether the state measures are adequately described in the supporting documentation and the plan submittal demonstrates that the state measures are quantifiable, verifiable, enforceable, non-duplicative and permanent as described above. This is necessary for the EPA to ensure that the results achieved through the plan are quantifiable and verifiable, and to assess whether the state measures are anticipated to achieve the state mass-based CO_2 goal for affected EGUs (or mass-based CO_2 goal plus new source complement).

The EPA's evaluation of the approvability of a state measures plan would also include an assessment of whether the backstop consisting of federally enforceable emission standards for the state's affected EGUs would ensure that the required emission performance level is fully achieved by affected EGUs, in the case that the state measures fail to achieve the state mass-based CO_2 goal (or mass-based CO_2 goal plus new source complement), or the state does not meet programmatic state measures milestones during the interim period. The trigger for the backstop must also satisfactorily provide for the implementation of the backstop emission standards.

b. *Considerations for the backstop included in a state measures type plan.*

As further discussed in section VIII.C.6.c, the EPA believes a backstop, composed of federally enforceable emission standards for the affected EGUs that are sufficient to achieve the state CO_2 emission goal or the CO_2 emission performance rates in the event that state measures do not result in the required CO_2 emission performance, is necessary for the state measures plan type to meet the requirements of CAA section 111(d). The state plan must specify the backstop that would apply federally enforceable emission standards to the affected EGUs if the state measures plan does not achieve the anticipated level of CO_2 emission performance by affected EGUs, or a state does not meet programmatic state measures milestones during the interim period. The state plan must include promulgated regulations (or other requirements) that fully specify these emission standard requirements, which must be quantifiable, verifiable, enforceable, non-duplicative and permanent. These requirements are described in more detail at section VIII.D.2.

These federally enforceable emission standards must be designed such that compliance by affected EGUs with the emission standards would achieve the CO_2 emission performance rates or state's rate- or mass-based interim and final goals for affected EGUs. The backstop emission standards must specify CO_2 emission performance levels that would apply for the interim plan performance period (including specifying levels for each of the interim step 1 through step 3 periods) and the final two-year plan performance periods.[795] If a state chose, these backstop emission standards could be based on a model rule or federal plan promulgated by the EPA.

The state measures plan must specify the trigger and conditions under which the backstop federally enforceable emission standards would apply that is consistent with the requirements in the emission guidelines. The trigger and attendant conditions for deployment of the backstop would address the CAA section 111(d) requirement that states submit a program that provides for the implementation of standards of performance. The state measures plan must specify the level of emission performance that will be achieved by affected EGUs as a result of implementation of the state measures plan during the interim and final plan performance periods. This includes the level of emission performance during the interim plan periods 2022–2024, 2025–2027 and 2028–2029, as well as the performance level that would be achieved during every subsequent 2-year final plan performance period (2030–2031, and subsequent 2-year periods). If actual CO_2 emission performance by affected EGUs fails to meet the level of emission performance specified in the plan over the 8-year interim performance period (2022–2029) or for any 2-year final goal performance period, the state measures plan must require that the backstop federally enforceable emission standards would take effect and be applied to affected EGUs. Similarly, the plan must require that the backstop standards take effect if actual emission performance is deficient by 10 percent or more relative to the performance levels that the state has chosen to specify in the plan for the interim step 1 period (2022–2024) or the interim step 2 period (2025–2027). The backstop standards are also triggered if, at the time of the state's annual reports to the EPA during the interim period, the state has not met the programmatic state measures milestones for the reporting period. The state measures plan must provide that, in the event the backstop is triggered, such emission standards would be effective within 18 months of the deadline for the state's submission of its periodic report to the EPA on state plan implementation and performance, as described in section VIII.D.2.c.[796] [797]

The backstop emission standards must make up for the shortfall in CO_2 emission performance. The shortfall must be made up as expeditiously as practicable. The state may address the requirement to make up for the shortfall in CO_2 emission performance by submitting, as part of the final plan, backstop emission standards that assure affected EGUs would achieve the state's interim and final CO_2 emission goals or the CO_2 emission performance rates for affected EGUs, and then later submit appropriate revisions to the backstop emission standards adjusting for the shortfall through the state plan revision process. The state may alternately effectuate this by submitting, along with the backstop emission standards, provisions to adjust the emission standards to account for any prior emission performance shortfall, such that no modification of the emission standards is necessary in order to address the emission performance shortfall.

For example, assume a state measures plan identified a mass-based CO_2 standard for affected EGUs of 100 million tons during the interim step 1 performance period (2022–2024), 90 million tons during the interim step 2 performance period (2025–2027), and 80 million tons during the interim step 3 performance period (2028–2029). Over the entire interim plan performance period (2022–2029), the interim mass-based CO_2 goal is cumulative emissions of 270 million tons. Assume that CO_2 emissions from affected EGUs in the interim step 1 period were actually 115 million tons, triggering implementation of the backstop. In this instance, the mass-based standard for affected EGUs implemented as part of the backstop during subsequent plan performance periods would need to ensure that cumulative CO_2 emissions during the 2022–2029 interim period do not exceed 270 million tons. This could be achieved, for example, by implementing a mass standard of 75 million tons during the interim step 2 performance period (rather than the 90 million tons originally specified in the plan), or some other combination during the remaining interim step 2 and 3 performance periods.[798] The emission standards included as the backstop in the plan must specify calculations for how such adjustments will be made.

4. Summary of Comments on State Plan Approaches

The EPA received a wide range of comments on the basic plan approaches in the proposal. Numerous commenters supported providing states with the option of implementing a rate-based or mass-based approach. Some commenters expressed concern that a rate-based approach would not reduce overall emissions, and could actually lead to increased emissions. The EPA does not agree with this latter comment, because both approaches would result in adequate and appropriate constraints on CO_2 emissions. As documented in the RIA, a rate-based approach would result in a substantial reduction in CO_2 emissions relative to emissions under a business-as-usual case.

Numerous commenters supported allowing states to implement a rate-based emission standard approach applied to affected EGUs. There was also broad support in comments for allowing states to pursue a mass-based approach in the form of mass emission standards on affected EGUs. The EPA is finalizing both of these approaches.

The EPA received a mix of comments for and against the proposed portfolio approach, in which state requirements and other measures that apply to non-EGU entities would be part of a state's federally enforceable state plan. Multiple commenters supported the portfolio approach because it would align with existing state and utility planning processes in the electric power sector, and would maximize state discretion and flexibility in developing plans. Commenters mentioned the range of state requirements and utility programs overseen by states that could be used under a portfolio approach and result in achieving the CO_2 emission goal for affected EGUs, including state RPS, EERS and utility-administered EE programs. Commenters noted that the portfolio approach would provide states maximum flexibility to take local circumstances, economics and state

[795] This includes the level of emission performance during the interim plan periods 2022–2024, 2025–2027 and 2028–2029, as well as the performance level that would be achieved during every subsequent 2-year final plan performance period (2030–2031, and subsequent 2-year periods).

[796] States may choose to establish an effective date for backstop emission standards that is sooner than 18 months.

[797] In the event a state does not implement the backstop as required if actual emission performance triggers the backstop, the EPA will take appropriate action. The EPA notes that as part of the proposed federal plan rulemaking, it is proposing a regulatory mechanism to call plans in the instances of substantial inadequacy to meet applicable requirements or failure to implement an approved plan.

[798] In this example, states could elect to implement different combinations of mass-based standards during the remaining interim step 2 and 3 plan performance periods, provided that cumulative CO_2 emissions during the full interim plan performance period (2022–2029) do not exceed 270 million tons.

policy into account when developing their plans.

By contrast, multiple commenters opposed the portfolio approach. Some commenters questioned how a portfolio approach would work, and whether the EPA had provided sufficient detail explaining how such a plan approach could be implemented by a state. In particular, multiple commenters questioned how different state programs, such as utility-administered EE programs, could be made federally enforceable in practice under CAA section 111(d).[799] Multiple commenters expressed concern about making state requirements and utility programs for RE and demand-side EE enforceable under the CAA. Some of these commenters supported the state commitments plan approach that the EPA took comment on in the proposal, which was a variant of the portfolio approach. Under the state commitment variant, measures that applied to entities other than affected EGUs would not be federally enforceable under the CAA, but state commitments to implement those measures would be federally enforceable elements of a state plan under the CAA.

After considering these comments, the EPA is not finalizing the portfolio approach or the state commitment variant. However, the EPA is finalizing the state measures plan type, as described above, which would accommodate state choices and allow states to rely upon a variety of measures, as was envisioned under the portfolio approach, in a way that meets the statutory requirements of CAA section 111(d).

5. Multi-State Plans and Multi-State Coordination

The EPA views the ability of a state to implement an individual plan or a multi-state plan as a significant flexibility that allows a state to tailor implementation of its plan to state policy objectives and circumstances. The EPA sees particular value in multi-state plans and multi-state coordination, which allow states to implement a plan in a coordinated fashion with other states. Such approaches can lead to more efficient implementation, lower compliance costs for affected EGUs and lower impacts on electricity ratepayers. Coordinated approaches also will help states identify and address any potential electric reliability impacts when developing plans.

[799] Legal considerations with the proposed portfolio approach are explored in section VIII.C.6.d.

The EPA received broad support in comments for allowing states to implement multi-state plan approaches, and has made multiple changes in the final rule to address many suggestions outlining different approaches states may want to take. These changes are intended to provide streamlined approaches for multi-state coordination while maintaining transparency and assuring that the CO_2 emission performance rates or state CO_2 emission goals are achieved.

The EPA is finalizing two approaches that allow states to coordinate implementation in order to meet the emission guidelines.[800]

First, states may meet the requirements of the emission guidelines and CAA section 111(d) by submitting multi-state plans that address the affected EGUs in a group of states. The EPA is finalizing the proposed approach by which multiple states aggregate their rate or mass CO_2 goals and submit a multi-state plan that will achieve a joint CO_2 emission goal for the fleet of affected EGUs located within those states (or a joint mass-based CO_2 goal plus a joint new source CO_2 emission complement).[801]

Second, the EPA is also finalizing another approach, in response to comments received on the proposed rule. This approach enables states to retain their individual state goals for affected EGUs and submit individual plans, but to coordinate plan implementation with other states through the interstate transfer of ERCs or emission allowances.[802] This approach facilitates interstate emission trading without requiring states to submit joint plans.[803] The EPA considers these to be individual state plans, not multi-state plans.

States have the option to implement this second approach in different ways, as discussed in section VIII.C.5.c. These different implementation options allow states to tailor their implementation of linked emission trading programs, based on state policy preferences, as well as economic and other considerations. These different options provide varying levels of state control over emission trading system partners and require varying levels of coordination in the course of state plan development.

[800] The EPA notes that in addition to these approved approaches, other types of multi-state approaches may be acceptable in an approvable plan, provided the obligations of each state under the multi-state plan are clear and the submitted plan(s) meets applicable emission guideline requirements.

[801] The concept of a new source CO_2 emission complement is addressed in section VIII.J.2.b. Table 14 provides individual state new source CO_2 emission complements. For a multi-state plan, a joint new source CO_2 emission complement would be the sum of the individual new source CO_2 emission complements in Table 14 for the states participating in the multi-state plan.

[802] This approach also applies where a state plan is designed to meet a state mass-based CO_2 goal plus a state's new source CO_2 emission complement.

[803] States may submit individual plans with such linkages, or if they choose, provide a joint submittal. Forms of joint submittals are described at section VIII.E.

In response to comments, the EPA is also further clarifying how multi-state plans with a joint goal for affected EGUs may be implemented. The EPA is clarifying that states may participate in more than one multi-state plan, if necessary, for example, to address affected EGUs in states that are served by more than one ISO or RTO. The EPA is further clarifying that a subset of affected EGUs in a state may participate in a multi-state plan. These clarifications are discussed in section VIII.C.5.d.

a. *Summary of comments on multi-state plans.*

Multiple commenters supported the EPA's proposed approach that would allow states to implement a multi-state plan to meet a joint CO_2 emission goal. However, a number of states commented that states should also be allowed to coordinate without aggregating multiple individual state goals into a single joint goal. Many states questioned the incentives that a state would have to aggregate its goal with other states that have different goals, and also noted the administrative complexities presented by states seeking to formally coordinate state plans with one another.

The EPA notes that there are multiple incentives for states to collaborate by implementing a multi-state plan to meet an aggregated joint goal, regardless of the specific level of their individual goals, because states share grid regions and impacts from plan implementation will be regional in nature. Further, multiple analyses, including those by ISOs and RTOs, indicate that regional approaches could achieve state goals at lesser cost than individual state plan approaches. However, the EPA also recognizes the value in allowing for collaboration where states retain individual goals. These approaches could provide some of the benefits of a joint goal while reducing the negotiations among states necessary to develop a multi-state plan with a joint goal. As a result, the EPA has finalized the additional approaches described in section VIII.C.5 to provide for coordination while maintaining individual goals. These approaches would allow for interstate transfer of ERCs or emission allowances while retaining individual state goals.

Many commenters suggested that states should be encouraged to join or form regional market-based programs. Many commenters touted the economic efficiency benefits of such approaches, and noted that such programs have features that support electric reliability.

The EPA agrees with these comments, and notes that it encouraged such approaches in the proposal. While the EPA is not requiring states to join and/or form regional market-based programs, we note that such programs can be helpful for many reasons, including features that support reliability. Market-based programs allow greater flexibility for affected EGUs both in the short-term and long-term. Under a market-based program, affected EGUs have the ability to obtain sufficient allowances or credits to cover their emissions in order to comply with their emission standards. Additionally, we continue to encourage states to cooperate regionally. Regional cooperation in planning and reliability assessments is an important tool to meeting system needs in the most cost-effective, efficient, and reliable way.

b. *Multi-state coordination through a joint emission goal.*

Multiple states may submit a multi-state plan that achieves an aggregated joint CO_2 emission goal for the affected EGUs in the participating states (or a joint mass-based CO_2 goal plus a joint new source CO_2 emission complement).[804] The joint emission goal approach is acceptable for both types of state plans, the ''emission standards'' plan type and the ''state measures'' plan type. However, the EPA is requiring that a joint goal may apply only to states implementing the same type of plan, either an ''emission standards'' plan or a ''state measures'' plan.[805]

Under this approach, a rate-based multi-state plan would include a weighted average rate-based emission goal, derived by calculating a weighted average CO_2 emission rate based on the individual rate-based goals for each of the participating states and 2012 generation from affected EGUs. A mass-based multi-state plan would include an aggregated mass-based CO_2 emission goal for the participating states, in cumulative tons of CO_2, derived by summing the individual mass-based CO_2 emission goals of the participating states.[806]

Such plans could include emission standards in the form of a multi-state rate-based or mass-based emission trading program.[807] Alternatively, states could submit a multi-state plan using a state measures approach.[808] Both approaches could provide for implementation of a multi-state emission trading program.

c. *Multi-state coordination among states retaining individual state goals.*

States that do not wish to pursue a joint CO_2 emission goal with other states may pursue a second pathway to multi-state collaboration. States may submit individual plans that will meet the CO_2 emission performance rates or a state mass CO_2 goal for affected EGUs (or mass-based CO_2 goal plus the new source CO_2 emission complement), but include implementation in coordination with other state plans by providing for the interstate transfer of ERCs or CO_2 allowances, depending on whether the state is implementing a rate-based or mass-based emission trading program. This form of coordinated implementation may occur under both an ''emission standards'' type of plan and a ''state measures'' type of plan, where states are implementing emission trading programs.[809] For rate-based plans, this type of coordinated approach is limited to state plans with rate-based emission standards that are equal to the CO_2 emission performance rates in the emission guidelines.

Under this approach, a state plan could indicate that ERCs or CO_2 allowances issued by other states with an EPA-approved state plan could be used by affected EGUs for compliance with the state's rate-based or mass-based emission standard, respectively. Such plans must indicate how ERCs or emission allowances will be tracked from issuance through use by affected EGUs for compliance,[810] through either a joint tracking system, interoperable tracking systems, or an EPA-administered tracking system.[811]

The EPA would assess the approvability of each state's plan individually—the use of ERCs or emission allowances issued in another state would not impact the approvability of the components of the individual state plan.[812] However, the EPA would also assess linkages with other state plans, to ensure that the joint tracking system or interoperable tracking systems used to implement rate-based or mass-based emission trading programs across states are properly designed with necessary components, systems, and procedures to maintain the integrity of the linked emission trading programs.

Coordinated state plan implementation among states that retain individual state mass-based CO_2 goals (or that implement individual state plans with rate-based emission standards consistent with the CO_2

---

[804] As a conceptual and legal matter, the relationship between states coordinating to meet a joint CO_2 emission goal under this rule is similar to the relationship between states coordinating SIP submissions to attain the NAAQS in an interstate nonattainment area. In both cases, the states coordinate their actions in a way that, cumulatively, the measures applicable in each state will lead to achievement of a common interstate goal (with the EPA evaluating the sufficiency and success of the plans on a holistic, interstate basis). Despite the shared goal, in both cases, the mere fact of coordination has no effect on each state's sovereign legal authority. For example, the legally applicable rules in a given state are adopted by that state individually, not by a joint entity or other interstate mechanism. Similarly, the fact that the states coordinate their rules does not grant them the authority to directly enforce each other's rules, or to take direct legal action against a state that is failing to implement its own rules. Although some states may jointly submit their coordinated rules to the EPA as a matter of administrative convenience, the state rules within such a plan are nothing more than reciprocal laws of the sort that states routinely enact in voluntary coordination with each other.

[805] This is necessary because if the joint goal is not achieved during a plan performance period, different remedies would apply under an emission standards plan and a state measures plan. Under an emission standards plan, corrective measures would be triggered. Under a state measures plan, the federally enforceable backstop emission standards would be triggered. See section VIII.F.3.

[806] Where a multi-state plan is designed to meet a joint mass-based CO_2 goal plus a joint new source CO_2 emission complement, the joint new source CO_2 emission complement would be the sum of the individual new source CO_2 emission complements in section VIII.J.2.b, Table 14, for the states participating in the multi-state plan.

[807] A potential example of this approach is the method by which the states participating in RGGI have implemented individual CO_2 Budget Trading Program regulations in a linked manner using a shared emission and allowance tracking system. Each state's regulations implementing RGGI stand alone on a legal basis, but provide for the use of CO_2 allowances issued in other participating states for compliance under the state regulations. These states are not listed by name in state regulations, which instead refer to participating states that have established a corresponding CO_2 Budget Trading Program regulation. More information is available at *http://www.rggi.org*.

[808] Under this approach, a state measure could include, if a state chose, a multi-state emission trading program that is enforceable at the state level.

[809] ERCs may only be transferred among states implementing rate-based emission limits. Likewise, emission allowances may only be transferred among states implementing mass-based emission limits.

[810] Referred to in different programs as ''surrender,'' ''retirement,'' or ''cancellation.''

[811] The EPA received a number of comments from states and stakeholders about the value of the EPA's support in developing and/or administering tracking systems to support state administration of rate-based emission trading programs. The EPA is exploring options for providing such support and is conducting an initial scoping assessment of tracking system support needs and functionality.

[812] Note that for mass-based plans, the approvability requirements for a state plan would differ, depending on the structure of the emission budget trading program included in the state plan. For example, approvability requirements and basic accounting with regard to whether a plan achieves a state's mass CO_2 goal would differ for emission budget trading programs that cover only affected EGUs subject to CAA section 111(d) vs. programs that apply to a broader set of emission sources. These considerations are addressed in section VIII.J.

emission performance rates in the emission guidelines) is discussed in more detail in sections VIII.J and K. Section VIII.J discusses coordinated implementation among states implementing individual mass-based emission budget trading programs and section VIII.K discusses coordinated implementation among states implementing individual rate-based emission trading programs.

d. *Multi-state plans that address a subset of EGUs in a state.*

The EPA is clarifying in the final emission guidelines that a state may participate in more than one multi-state plan. Under this approach, the state would identify in its submittal the subset of affected EGUs in the state that are subject to the multi-state plan or plans. This could involve a subset of affected EGUs that are subject to a multi-state plan, with the remainder of affected EGUs subject to a state's individual plan. Alternatively, different affected EGUs in a state may be subject to different multi-state plans. In all cases, the state would need to identify in each specific plan which affected EGUs are subject to such plan, with each affected EGU subject to only one multi-state plan or subject only to the state's individual plan (if relevant).

These scenarios may occur where a state chooses to cover affected EGUs in different ISOs or RTOs in different multi-state plans. This will provide states with flexibility to participate in multi-state plans that address the affected EGUs in a respective grid region, in the case where state borders cross grid regions.

These scenarios may also occur where a state is served by multiple vertically integrated electric utilities with service territories that cross state lines. This will provide states with flexibility to participate in multi-state plans that address the affected EGUs owned and operated by a utility with a multi-state service territory.

6. Legal Bases and Considerations for State Plan Types and Approaches

a. *Legal basis for emission standards approach.*

The emission standards approach is consistent with the requirements of CAA section 111(d). If a state simply adopts the CO_2 emission performance rates, then the corresponding rate-based emission standards in the state plan establish standards of performance for affected EGUs as required under section 111(d)(1)(A). Similarly, if a state chooses to achieve the rate-based CO_2 emission goal through rate-based emission standards applicable only to affected EGUs, or to achieve the mass-based CO_2 emission goal through mass-based emission standards applicable only to affected EGUs (or, alternatively, to achieve the mass CO_2 goal and a new source CO_2 emission complement through federally enforceable mass-based emission standards in conjunction with state enforceable emission standards on new sources), then the set of rate-based emission standards or the set of mass-based emission standards in the state plan establishes standards of performance for affected EGUs as required under section 111(d)(1)(A). The EPA has the authority to approve emission standards for affected EGUs as part of a state plan under all three cases (as long as such emission standards meet the requirements of CAA section 111(d) and the final emission guidelines), thereby making such emission standards federally enforceable upon approval by the EPA. In all three cases, the emission standards must be quantifiable, verifiable, enforceable, non-duplicative and permanent; this ensures that the plan provides for implementation and enforcement of the standards of performance (*i.e.* the emission standards) as required by section 111(d)(1)(B). Finally, as described in section VIII.B.7.b below, standards of performance may include emission trading. Thus, the credit and allowance trading that is allowed under the emission standards approach is consistent with the statutory requirement that the plan establish standards of performance.

We note that the standard the statute provides for the EPA's review of a state plan is whether it is ''satisfactory.'' We interpret a ''satisfactory'' plan as one that meets all applicable requirements of the CAA, including applicable requirements of these guidelines. Some commenters suggested that ''satisfactory'' should be taken to mean something less (such as mostly or substantially meeting requirements) but the structure of 111(d) shows otherwise. When a state plan is unsatisfactory, section 111(d)(2) gives the EPA the ''same'' authority to promulgate a federal plan as the EPA has under section 110(c). Under section 110(c), the EPA has authority to promulgate a federal implementation plan if a SIP does not comply with all CAA requirements (see sections 110(k)(3) and 110(l)).

For example, if an emission standards type plan includes an emission standard that is unenforceable due to defective rule language, then the plan is not satisfactory because it does not comply with the guideline requirement that emission standards must be enforceable. On the other hand, if a state plan complies with all applicable requirements of the CAA (including these guidelines), then the EPA must approve it as satisfactory. This is true even if the emission standards in the state plan are more stringent than the minimum requirements of these guidelines, or the state plan achieves more emission reductions than required by these guidelines. This follows from section 116 of the CAA as interpreted by the U.S. Supreme Court in *Union Elec. Co.* v. *EPA,* 427 U.S. 246, 263–64 (1976).

b. *Legal basis for emissions trading in state plans.*

There are three legal considerations with respect to emissions trading in state plans. First, we explain how the definition of ''standard of performance'' in section 111(a)(1) allows section 111(d) plans to include standards of performance that authorize emissions trading. Second, we explain how the EPA interprets the phrase ''provides for implementation and enforcement of [the] standards of performance'' in the context of a rate-based ERC trading program. Third, we give a similar explanation of the EPA's interpretation of the same phrase in the context of a mass-based allowance trading program.

(1). In the proposal, the EPA proposed that CAA section 111(d) plans may include standards of performance that authorize emissions averaging and trading. 79 FR 34830, 34927/1 (June 18, 2014). We are finalizing that states may include the use of emission trading in approvable state plans.

For purposes of this legal discussion, in the case of an emission limitation expressed as an emission rate, trading takes the form of buying or selling ERCs that an affected EGU may generate if its actual emission rate is lower than its allowed emission rate or that an eligible resource may generate. In the case of an emission limitation expressed as a mass-based limit, trading takes the form of buying or selling allowances.

As quoted in full above, the definition of ''standard of performance'' under CAA section 111(a)(1) is a ''standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which . . . the Administrator determines has been adequately demonstrated.''

Both an emission rate that may be met through tradable ERCs, and a mass limit requirement that emissions not exceed the number of tradable allowances surrendered by an affected source, qualify as a ''standard for emissions.'' The term ''standard'' is not defined, but its everyday meaning is a rule or requirement,[813] which, under the only (or at least a permissible) reading of the provision, would include an emission rate that may be met through tradable ERCs and a requirement to retire tradable allowances.

Treating a tradable emission rate or mass limit requirement as a ''standard of performance'' is consistent with past EPA practice. In the Clean Air Mercury Rule, promulgated in 2005, the EPA established tradable mass limits as the emission guidelines for certain air pollutants from fossil fuel-fired EGUs, and explained that a tradable mass limit qualifies as a ''standard for emissions.''[814] In addition, in the 1995 Municipal Solid Waste (MSW) Combustor rule the EPA authorized emission trading by sources.[815]

It should be noted that CAA section 302(l) includes another definition of ''standard of performance,'' which is ''a requirement of continuous emission reduction, including any requirement relating to the operation or maintenance of a source to assure continuous emission reduction.'' As described above, section 111(d) contains its own, more specific definition of ''standard of performance,'' which a tradable emission rate or mass limit satisfies. Whether or not section 302(l) applies in light of section 111(d)'s more specific definition, a tradable emission rate or mass limit also meets section 302(l)'s requirements. A tradable emission rate applies continuously in that the source is under a continuous obligation to meet its emission rate, and that is so regardless of the averaging time, *e.g.,* a rate that must be met on an annual basis. Similarly, a mass limit requirement implemented through the use of allowances applies continuously in that the source is continuously under an obligation to assure that at the appropriate time, its emissions will not exceed the allowances it will surrender. In this respect, a tradable emission rate or mass limit requirement is similar to a non-tradable emission rate that must be met over a specified period, such as one year. In all of these cases, a source is continuously subject to its requirement although it may be able to emit at different levels at different points in time. It should also be noted that a tradable emission rate or mass limit requirement is appropriate for CO_2 emissions, the air pollutant covered by this rule, because the environmental effects of CO_2 emissions are not dependent on the location of the emissions.

(2). In our final rule, we are prescribing certain specific requirements for trading systems for ERCs in a rate-based approach. These specific requirements are in addition to the generic requirements for any state plan (see section VIII.D.2.d below for the legal basis for the generic components for state plans) and are intended to ensure the integrity of the ERC trading system. The integrity of the trading system is key to ensuring that a state plan provides for implementation and enforcement of the standards of performance, as required by section 111(d)(1)(B). Requirements relating to ERCs in a rate-based trading system, and allowances in a mass-based system, must also be submitted as federally enforceable components of the state plan, as such requirements provide for the implementation and enforcement of a tradable emission rate or mass limit for an affected EGU.

However, as described in section VIII.C.6.d, the EPA has legal concerns regarding whether federally enforceable requirements under a CAA section 111(d) state plan can be imposed on entities other than affected EGUs. It is important to note that the use of ERCs and inclusion of state plan requirements regarding a rate-based trading system, and the use of allowances and inclusion of state plan requirements regarding a mass-based trading system, does not run afoul of these legal concerns, as neither the requirements of section 111(d) nor of the federally enforceable state plan in either case extend to non-EGU generators or third-party verifiers of such compliance units.

(3). In our final rule, we are prescribing certain specific requirements for trading systems for allowances in a mass-based approach. These specific requirements are in addition to the generic requirements for any state plan (see section VIII.D.2.d below for the legal basis for the generic requirements for state plans) and are intended to ensure the integrity of the allowance trading system. The integrity of the trading system is key to ensuring that a state plan provides for implementation and enforcement of the standards of performance.

c. *Legal basis for state measures plan type.*

The EPA believes the state measures plan type is consistent with CAA section 111(d). Section 111(d)(1) requires a state to submit a plan that ''(A) establishes standards of performance for any existing source for [certain] air pollutant[s] . . . and (B) provides for the implementation and enforcement of such standards of performance.'' Section 111(d)(2)(A) indicates that the EPA must approve the state plan if it is ''satisfactory.''

For states that choose to adopt and submit a state measures plan, such state must submit a state plan that includes standards of performance for CO_2 emissions from affected EGUs in the form of a federally enforceable backstop in order to meet the requirements of section 111(d). Section 111(d) unambiguously requires a state to submit a plan that establishes standards of performance for certain sources, but does not mandate when such standards of performance must be in effect or implemented in order to meet applicable compliance deadlines. Instead, Congress has delegated to the EPA the determination of the appropriate effective date of standards of performance submitted under state plans to meet the requirements of section 111(d). In other words, where the statute is silent, the EPA has authority to provide a reasonable interpretation. The EPA's interpretation is that for states that submit state plans establishing standards of performance under section 111(d), the effective date of such standards of performance may be later in time, perhaps indefinitely, for a number of reasons and under certain conditions. A key condition is that the state plan provides for the achievement of the required reduction by means other than the standards of performance on the timetable required by the BSER, with provision for federally enforceable standards of performance to be implemented if those other means fall short. The EPA believes it is reasonable to defer the effective date for standards of performance for affected EGUs as long as affected EGU CO_2 emissions are projected to achieve, and do achieve, the requisite state goal.

Additionally, under the state measures plan type, if a state chooses to impose emission standards for the affected EGUs in conjunction with state measures that apply to other entities for any period prior to the triggering of the backstop, this final rule requires such emission standards to be submitted as federally enforceable measures included in the state plan. The EPA believes this is appropriate to help ensure the performance of a state measures plan will meet the requirements of this final rule. Section 111(d) clearly authorizes states to impose, and the EPA to approve, federally enforceable emission standards for affected EGUs. Though federally enforceable emission standards for affected EGUs in a state

[813] E.g., ''Something that is set up and established by authority as a rule for the measure of quantity, weight, value, or quality.'' Webster's Third New International Dictionary 2223 (1967); see also The American College Dictionary (C.L. Barnhart, ed. 1970) (''an authoritative model or measure'').

[814] 70 FR 28606, 28616–17 (May 18, 2005).

[815] 60 FR 65387, 6540/2 (Dec. 19, 1995).

measures plan themselves would not necessarily achieve the requisite state goals, the EPA is authorized to approve state plans when they satisfactorily meet applicable requirements. The EPA can evaluate whether a state measures plan is satisfactory by determining whether any federally enforceable emission standards for affected EGUs in conjunction with state measures on other entities will result in the achievement of the requisite emissions performance level. As previously explained in this final rule, the performance rates and the state goals are the arithmetic expression of BSER as applied across affected EGUs in a state as a source category. In a state measures plan, the evaluation of whether a state measures plan is satisfactory goes to evaluating both the state measures and any federally enforceable emission standards on the affected EGUs to determine whether the plan as a whole will result in the affected EGUs achieving the applicable goals that reflect BSER.

Section 111(d)(1)(B) also requires a state to submit a program that provides for the implementation and enforcement of the applicable standards of performance. Under the state measures approach, this requirement regarding implementation is satisfied in part by the submission of an approvable trigger mechanism for the backstop and appropriate monitoring, reporting and recordkeeping requirements. The trigger mechanism provides for the ''implementation'' of the backstop, *i.e.,* the standards of performance, by putting the backstop into effect once the associated trigger is deployed. In other words, when the CO_2 performance level under a state plan exceeds the trigger as described in section VIII.C.4.b, the emission standards that were submitted as the federally enforceable backstop and any attendant requirements must be implemented and in effect. The statutory requirement under CAA section 111(d)(2) regarding enforcement is also satisfied under the state measures plan type by the state submitting standards of performance sufficient to meet the requisite emission performance rates or state goal, in the form of the backstop, for inclusion as part of the federally enforceable state plan.

Additionally, by requiring states that choose to impose emission standards on affected EGUs under the state measures approach to submit such emission standards for inclusion in the federally enforceable plan, this requirement further provides for implementation and enforcement as required by the statute. Regulating the affected EGUs through federally enforceable emission standards themselves in conjunction with any state measures the state chooses to rely upon further assures the likelihood of the affected EGUs achieving the state goals as required under this rule and section 111(d).

The state measures plan is a variation of the proposed portfolio approach in that both plan types allow the state to rely upon measures that impose requirements on sources other than affected EGUs in meeting the requisite state CO_2 emission goal. The state measures plan type is also a variation of the proposed state commitment approach in that the measures involving entities other than affected EGUs are not included as part of the federally enforceable 111(d) state plan, but the state may rely upon such measures that have the effect of reducing CO_2 emissions from affected EGUs as a matter of state law. The EPA took comment on the proposed portfolio approach and state commitment approach, and on the utilization of measures on entities other than affected EGUs in meeting the requirements of the emission guidelines and CAA section 111(d). With respect to the proposed state commitment approach, the EPA received comments recommending that the EPA require a federally enforceable backstop with emission standards sufficient to achieve the requisite CO_2 emission performance. The backstop component the EPA is finalizing as part of the state measures plan type is consistent with the EPA's statements in the proposal regarding states' obligations under section 111(d) to establish emission standards for affected EGUs, as the backstop contains federally enforceable emission standards for affected EGUs that will achieve the requisite CO_2 emission performance, and is consistent with comments received regarding the proposed state commitment approach.

The state measures plan type the EPA is finalizing is also a logical outgrowth of the comments received on the proposed portfolio approach. As further explained below, legal questions remain as to whether state plans under section 111(d) can include federally enforceable measures that impose requirements on sources other than affected EGUs. However, a number of commenters and stakeholders expressed robust support for the ability to rely on measures and programs that do not impose requirements on affected EGUs themselves through plan types such as the proposed portfolio and state commitment approaches. The EPA is reasonably interpreting 111(d) as authorizing the state measures plan type, and believes this plan type is also responsive to, and accommodating of, states and stakeholders who have expressed the importance of being able to rely upon various measures that have the effect of reducing CO_2 emissions from affected EGUs. The EPA is finalizing the state measures plan type upon careful consideration of statutory requirements and comments received based on the proposed portfolio approach and state commitment approach.

The EPA additionally notes that the state measures plan type is not precluded by the recent Ninth Circuit Court of Appeals' decision in *Committee for a Better Arvin et al.* v. *US EPA et al.,* Nos. 11–73924 and 12–71332 (May 20, 2015). The court held that the EPA violated the CAA by approving a California SIP which relied on emission reductions from state-only mobile source standards (''waiver measures'') without including those standards in the SIP. The court first looked at the plain language of section 110(a)(2)(A) of the CAA, which states that SIPs ''shall include'' the emission limitations and other control measures on which a state relies to comply with the CAA. The court then stated that the EPA's action was also inconsistent with the structure of the CAA. The EPA has the primary responsibility to protect the nation's air quality, but in the court's view, the EPA itself would be unable to enforce the state-only standards. In addition, the court stated that the EPA's action was inconsistent with citizens' right to enforce SIP provisions under section 304.

There are a number of reasons why this decision does not preclude the state measures plan type. The Ninth Circuit's textual analysis does not apply here, as the language of section 110(a)(2)(A) does not control for 111(d) state plans. Section 111(d)(1) requires state plans to ''establish standards of performance'' and to ''provide for implementation and enforcement'' of the standards of performance, but, unlike section 110(a)(2)(A), section 111(d) does not specifically say that every emission reduction measure must be ''included'' in the state plan and be made federally enforceable. Even if section 111(d) did impose such requirements, the state measures approach satisfies them because the trigger is included in the plan as a federally enforceable implementation measure, and the backstop included in the plan also contains standards of performance that reflect the BSER and are federally enforceable once they are triggered.

The Ninth Circuit's structural analysis also does not apply. The availability of the trigger and backstop gives the EPA and citizens a federally enforceable route to ensure that all necessary emission reductions take place in order to achieve the standards of performance. This is markedly different than the state-only standards, where according to the Ninth Circuit, the EPA and citizens had no route to ensure that all necessary emission reductions took place in order to attain the NAAQS. In addition, case law suggests that federal enforceability for every requirement may not be necessary when there are sufficient federally enforceable requirements to satisfy the statute, see *National Mining Ass'n* v. *United States EPA,* 59 F.3d 1351 (D.C. Cir. 1995); in this case federal enforceability for the state-only measures is not necessary to meet the statutory requirements of section 111(d)(1) as the federally enforceable trigger and backstop are sufficient.

d. *Legal considerations with proposed portfolio approach.*

The EPA is not finalizing the portfolio approach that was included in the proposed rulemaking, 79 FR 34830, 34902 (June 18, 2014). In the proposal, the EPA noted that the portfolio approach raised legal questions. 79 FR 34830, 34902–03. A number of commenters stated that the portfolio approach is unlawful because it exceeds the limitations that section 111(d)(1) places on state plans. Upon further review, we agree with these comments.

Section 111(d)(1) provides that state plans shall ''establish[] ''standards of performance for any existing source'' and ''provide[] for the implementation and enforcement of . . . standards of performance'' under CAA section 111(d)(1). Although in the proposal we identified possible interpretations of section 111(d)(1) that could justify the proposed portfolio approach, after reviewing the comments, we are not adopting those interpretations. Because section 111(d)(1) specifically requires state plans to include only (A) standards for emissions imposed on affected sources and (B) measures that implement and enforce such standards,[816] we interpret it as allowing federal enforceability only of requirements or measures that are in those two specifically required provisions. We therefore do not interpret the term ''implementation of . . . such standards of performance'' to authorize the EPA to approve state plans with obligations enforceable against the broad array of non-emitting entities that would have been implicated by the portfolio approach. Thus, the EPA is not finalizing the portfolio approach, and in the event that states submit such measures to the EPA for inclusion in the state plan, the EPA would not approve them into the state plan and therefore would not make them federally enforceable.

We note that section 111(d) limits on federal enforceability of requirements against non-affected sources do not imply that the BSER cannot be based on actions by non-affected sources. As discussed in section V, the BSER may be based on the ability of owners/operators of affected sources to engage in commercial relationships with a wide range of other entities, from the vendors, installers, and operators of air pollution control equipment to, in this rulemaking, owners/operators of RE.

The EPA notes it is also not finalizing the proposed state commitment approach or state crediting approach. The EPA believes the finalized state measures plan type provides states with the same flexibilities as would have been allowed under these two proposed approaches, and does so in a way that is legally supportable by the CAA. Therefore, the EPA does not believe it necessary to finalize the state commitment approach or state crediting approach.

e. *Legal basis for multi-state plans.*

While nothing in section 111(d)(1) explicitly authorizes either states to adopt and submit multi-state plans, or the EPA to approve them as satisfactory, nothing in section 111(d)(1) explicitly prohibits it, either. In addition, nothing in section 111(d)(2)(A)'s standard of ''satisfactory'' prohibits the EPA from considering multi-state plans as satisfactory. There is thus a gap that the EPA may reasonably fill.

In light of the purpose of these emission guidelines, to reduce emissions of a pollutant that globally mixes in the stratosphere, and the mechanisms to reduce those emissions, which may have beneficial effects across state lines, it is reasonable to allow for multi-state plans. Thus, our gap-filling interpretation of section 111(d) in this context is reasonable.

D. State Plan Components and Approvability Criteria

1. Approvability Criteria

In the ''Criteria for Approving State Plans'' section of the preamble to the June 2014 proposal (section VIII.C), the EPA proposed the following as necessary components of an approvable state plan:

1. The plan must contain enforceable measures that reduce EGU CO_2 emissions;

2. The projected CO_2 emission performance by affected EGUs must be equivalent to or better than the required CO_2 emission performance level in the state plan;

3. The EGU CO_2 emission performance must be quantifiable and verifiable;

4. The plan must include a process for state reporting of plan implementation, CO_2 emission performance outcomes, and implementation of corrective measures, if necessary.

After reviewing the comments we received concerning the approvability criteria, the EPA has decided against maintaining the four proposed approvability criteria separately from the list of components required for an approvable plan, which may be confusing and potentially redundant. The EPA has determined that a satisfactory state plan that meets the required plan components discussed below will inevitably meet the proposed approvability criteria. The EPA, therefore, has incorporated the proposed approvability criteria into the section titled ''Components of a state plan submittal'' (section VIII.D.2 below). There is no functional change in the approvability criteria or the components of a state plan addressed in the proposal; they are simply combined and this change does not have a substantive effect on state plan development or approval.

Under the proposed ''Enforceable Measures'' criterion (section VIII.C.1 of the proposal preamble), the EPA specifically requested comment on the appropriateness of applying existing EPA guidance on enforceability to state plans under CAA section 111(d), considering the types of entities that might be included in a state plan.[817]

The EPA also requested comment on whether the agency should provide guidance on enforceability considerations related to requirements in a state plan for entities other than affected EGUs, and if so, what types of entities. Comments received strongly suggested that the EPA provide guidance on enforceability considerations for non-EGU affected entities, particularly for RE and EE. Comments also requested additional guidance specific to this rulemaking, including examples of enforceable measures for specific activities, such as

[816] Such measures include, for example, in this rule, requirements for ERCs.

[817] The existing guidance documents referenced were: (1) September 23, 1987 memorandum and accompanying implementing guidance, ''Review of State Implementation Plans and Revisions for Enforceability and Legal Sufficiency,'' (2) August 5, 2004 ''Guidance on SIP Credits for Emission Reductions from Electric-Sector Energy Efficiency and Renewable Energy Measures,'' and (3) July 2012 ''Roadmap for Incorporating Energy Efficiency/Renewable Energy Policies and Programs into State and Tribal Implementation Plans, Appendix F.''

solar thermal technologies, waste heat recovery, net-metering energy savings and state RPS.

These enforcement considerations arose primarily under the proposed portfolio approach for state plans, which would have allowed state plans to include federally enforceable measures that apply to entities that are not affected EGUs. In this action, the EPA is finalizing the state measures approach instead of the portfolio approach, under which a state can rely upon measures that are not federally enforceable as long as the plan also includes a backstop of federally enforceable emission standards that apply to affected EGUs. As explained in depth in section VIII.C, if the state is adopting the state measures approach, the state plan submittal will need to specify, in the supporting materials, the state-enforceable measures that the state is relying upon, in conjunction with any federally enforceable emission standards for affected EGUs, to meet the emission guidelines. As part of the state measures approach, the EPA is finalizing a requirement for a federally enforceable backstop, which requires the affected EGUs to meet emission standards that fully achieve the CO_2 emission performance rates or the state's CO_2 emission goal if the state measures do not meet the state's mass-based CO_2 emission goal. Because the EPA is not finalizing the portfolio approach, which would have allowed states to include federally enforceable measures in a state plan that apply to entities that are not affected EGUs, the agency is not providing additional guidance on federal enforceability of measures that might apply to such entities. As proposed, we are requiring that state plans include a demonstration that plan measures are enforceable, which for emission standards plan types is discussed in section VIII.D.2.b.3 below and for state measures plan types is discussed in section VIII.D.2.c.6 below.

Commenters also requested that the EPA allow states to rely on provisions with flexible compliance mechanisms in state plans and clarify how to address flexible compliance mechanisms when demonstrating achievement of a state CO_2 emission goal. Additionally, a commenter requested that the enforceability mechanisms that the EPA requires in state plans should support existing programs, as well as new programs in other states, by minimizing program changes required purely to conform with federal requirements, while still providing enough additional program review and accounting to ensure that CO_2 emission reductions are achieved. These and related comments contributed to the EPA's decision to finalize the option for states to submit a state measures plan, which would be comprised, at least in part, of measures implemented by the state that are not included as federally enforceable components of the plan, with a backstop of federally enforceable emission standards for affected EGUs that fully meet the emission guidelines and that would be triggered if the plan failed to achieve the CO_2 emission performance levels specified in the plan on schedule. For more information on the state measures plan approach, see section VIII.C.3 of this preamble above.

2. Components of a State Plan Submittal

In this action, the EPA is finalizing that a state plan submittal must include the components described below. As a result of constructive comments received from many commenters and additional considerations, the EPA is finalizing state plan components that are responsive to that input and are appropriate for the types of state plans allowed in the final emission guidelines. A state plan submittal must also be consistent with additional specific requirements elsewhere in this final rule and with the EPA implementing regulations at 40 CFR 60.23–60.29, except as otherwise specified by this final rule. These requirements apply to both individual state plan submittals and multi-state plan submittals. When a state plan submittal is approved by the EPA, the EPA will codify the approved CAA section 111(d) state plan in 40 CFR part 62. Section VIII.D.3 discusses the components of a state plan submittal that would be codified as the state CAA section 111(d) plan when the state plan submittal is approved by the EPA.

The EPA is finalizing that states can choose to meet the emission guidelines through one of two types of state plans: an emission standards plan type or a state measures plan type. A state pursuing the emission standards plan type may opt to submit a plan that meets the CO_2 emission performance rates for affected EGUs or meets the state rate-based or mass-based CO_2 emission goal for affected EGUs. A state implementing a state measures approach plan type must submit a plan where the state measures, in conjunction with any emission standards on the affected EGUs, result in achievement of the state mass-based CO_2 goal for affected EGUs. The backstop required to be submitted as part of a state measures plan may achieve the CO_2 emission performance rates for affected EGUs or the state rate-based or mass-based CO_2 emission goal. The content of the state plan submittal will vary depending on which plan type the state decides to adopt. States that choose to participate in multi-state plans must adequately address plan components that apply to all participating states in the multi-state plan.

The rest of this section covers components that are required for all types of plans, as well as components specific to each specific type of plans. Section VIII.D.2.a addresses the components required for all plan submittals. Section VIII.D.2.b addresses the additional components required for submittals under the emission standards plan type. Section VIII.D.2.c addresses additional components required for submittals under the state measures plan type.

a. *Components required for all state plan submittals.*

The EPA is finalizing requirements that a final plan submittal must contain the following components, in addition to those in either section VIII.D.2.b (for the emission standards plan type) or VIII.D.2.c (for the state measures plan type) of this section.

(1) *Description of the plan approach and geographic scope.*

The description of the plan type must indicate whether the state will meet the emission guidelines on an individual state basis or jointly through a multi-state plan, and whether the state is adopting an emission standards plan type or a state measures plan type. For multi-state plans this component must identify all participating states and geographic boundaries applicable to each component in the plan submittal. If a state intends to implement its individual plan in coordination with other states by allowing for the interstate transfer of ERCs or emission allowances, such links must also be identified.[818]

(2) *Applicability of state plans to affected EGUs.*

The state plan submittal must list the individual affected EGUs that meet the applicability criteria of 40 CFR 60.5845 and provide an inventory of CO_2 emissions from those affected EGUs for the most recent calendar year prior to plan submission for which data are available.

(3) *Demonstration that a state plan will achieve the CO_2 emission performance rates or state CO_2 emission goal.*

A state plan submittal must demonstrate that the federally

[818] If applicable, this plan component must also identify if the plan is being submitted as a "ready-for-interstate-trading" plan, as discussed in section VIII.J.3 and VIII.K.4.

enforceable emission standards for affected EGUs and/or state measures are sufficient to meet either the CO_2 emission performance rates or the state's CO_2 emission goal for affected EGUs in the emission guidelines for the interim and final plan performance periods. This includes during the interim period of 2022–2029, including the interim step 1 period (2022–2024); interim step 2 period (2025–2027); and interim step 3 period (2028–2029) period, as well as during the final period of 2030–2031 and subsequent 2-year periods.[819] A demonstration of CO_2 emission performance is required through 2031. For the post-2031 period, the demonstration requirement may be satisfied by showing that emission standards or state measures on which the demonstration through 2031 is based are permanent and will remain in place. As discussed in more detail in section VIII.J, states adopting a plan based upon a mass-based state CO_2 emission goal must demonstrate that they have addressed the risk of potential emission leakage in their mass-based state plan.

The type of demonstration of CO_2 emission performance and documentation required for such a demonstration in a state plan submittal will vary depending on how the CO_2 emission standards for affected EGUs and/or state measures in a state plan are applied across the fleet of affected EGUs in a state, as discussed below.[820]

(a) *State plan type designs that require a projection of CO_2 emission performance.* Whether a projection of affected EGU CO_2 emission performance must be included in a state plan submittal depends on the design of the state plan. The following plan designs do not require a projection of CO_2 emission performance by affected EGUs under the state plan because they ensure that the CO_2 emission performance rates or state rate-based or mass-based CO_2 goals are achieved when affected EGUs comply with the emission standards:

- State plan establishes separate rate-based CO_2 emission standards for affected fossil fuel-fired electric utility steam generating units and stationary combustion turbines (in lb CO_2/MWh) that are equal to or lower than the CO_2 emission performance rates in the emission guidelines during the interim and final plan performance periods.
- State plan establishes a single rate-based CO_2 emission standard for all affected EGUs that is equal to or lower than the state's rate-based CO_2 goal in the emission guidelines during the interim and final plan performance periods.
- State plan establishes mass-based CO_2 emission standards for affected EGUs that cumulatively do not exceed a state's mass-based CO_2 goal in the emission guidelines during the interim and final plan performance periods.
- State plan establishes mass-based CO_2 emission standards for affected EGUs that, together with state enforceable limits on mass emissions from new EGUs, cumulatively do not exceed the state's EPA-specified mass CO_2 emission budget[821] in the emission guidelines during the interim and final plan performance periods.

All other state plan designs must include a projection of CO_2 emission performance by affected EGUs under the state plan.

For example, if a state chooses to apply rate-based CO_2 emission standards to individual affected EGUs, or to subcategories of affected EGUs (such as fossil fuel-fired electric utility steam generating units and stationary combustion turbines), at a lb CO_2/MWh rate that differs from the CO_2 emission performance rates or the state's rate-based CO_2 goal in the emission guidelines, then a projection is required. Also, if a state chooses to implement a mass-based program including both affected EGUs and new EGUs, but with total allowable emissions in excess of the presumptively approvable EPA-specified mass CO_2 emission budget for that state, the state must provide a projection of CO_2 emission performance. Likewise, if a state chooses a state measures state plan approach, a projection of CO_2 emission performance is required.

(b) *Methods and tools.* A satisfactory demonstration of the future CO_2 emission performance of affected EGUs must use technically sound methods that are reliable and replicable. A state plan submittal must explain how the projection method and/or tool works and why the method and/or tool chosen is appropriate considering the type of emission standards and/or state measures included (or relied upon, in the case of state measures) in a state plan. The results of the demonstration must be reproducible using the documented assumptions described in the state plan submittal. The method and projection of EGU generation and CO_2 emissions can differ from the EPA's forecast in the RIA. The EPA received comments on whether it would require specific modeling tools and input assumptions. Commenters raised concerns that the EPA may require states to use proprietary models, and that states do not have the financial resources to use such models. The EPA is not requiring a specific type of method or model, as long as the one chosen uses technically sound methods and tools that establish a clear relationship between electricity grid interactions and the range of factors that impact future EGU economic behavior, generation, and CO_2 emissions. The EPA will assess whether a method or tool is technically sound based on its capability to represent changes in the electric system commensurate to the set of emission standards and state measures in a state plan while accounting for the key parameters specified in section VIII.D.2.a.(3)(c) below. Including a base case CO_2 emission projection in the state plan submittal (*i.e.,* one that does not include any federally enforceable CO_2 emission standards included in a plan or state-enforceable measures referenced in a plan submittal), will help facilitate the EPA's assessment of the CO_2 emission performance projection. Methods and tools could range from applying future growth rates to historical generation and emissions data, using statistical analysis, or electric sector energy modeling.

(c) *Required documentation of projections.* When required to provide a CO_2 emission performance projection, the state must also provide comprehensive documentation of analytic parameters for the EPA to assess the reasonableness of the projection. The analytic parameters, when considered as a whole, should reflect a logically consistent future outlook of the electric system. Refer to the Incorporating RE and Demand-side EE Impacts into State Plan Demonstrations TSD of the final rule for further details on quantifying impacts of eligible RE and demand-side EE measures.

The CO_2 emission performance projection documentation must include:

[819] State plans may meet the CO_2 emission performance rates in the emission guidelines during the interim plan performance step periods, or assign different interim step CO_2 emission performance rates, provided the CO_2 emission performance rates in the emission guidelines are achieved during the full interim period. Likewise, a state plan may meet the interim step state CO_2 emission goals in the emission guidelines or establish different interim step CO_2 emission levels, provided the state interim CO_2 goal is achieved during the full interim period.

[820] For simplicity, the EPA refers here to state measures under a state measures plan as being included ''in the state plan'' although such state-enforceable measures are not codified as part of the federally enforceable approved state plan. However, the approval of a state measures plan is dependent on a demonstration in the state plan submittal that those state-enforceable measures meet the requirements in the emission guidelines and that those state measures, alone or in combination with federally enforceable emission standards for affected EGUs, will meet the mass-based CO_2 goal.

[821] A state's EPA-specified mass CO_2 emission budget is the state's mass-based CO_2 goal for affected EGUs plus the EPA-specified new source CO_2 emission complement. See section VIII.J.2.b.

- Geographic representation, which must be appropriate for capturing impacts and/or changes in the electric system
- Time period of analysis, which must extend through 2031
- Electricity demand forecast (MWh load and MW peak demand) at the state and regional level. If the demand forecast is not from NERC, an ISO or RTO, EIA, or other publicly available source, then the projection must include justification and documentation of underlying assumptions that inform the development of the demand forecast, such as annual economic and demand growth rate, population growth rate.
- Planning reserve margins
- Planned new electric generating capacity
- Analytic treatment of the potential for building unplanned new electric generating capacity
- Wholesale electricity prices
- Fuel prices, when applicable;
- Fuel carbon content
- Unit-level fixed operations and maintenance costs, when applicable;
- Unit-level variable operations and maintenance costs, when applicable;
- Unit-level capacity
- Unit-level heat rate
- If applicable, EGU-specific actions in the state plan designed to meet the required CO_2 emission performance, including their timeline for implementation
- If applicable, state-enforceable measures, with electricity savings and renewable electricity generation (MWhs) expected for individual and collective measures, as applicable. Quantification of MWhs expected from EE and RE measures will involve assumptions that states must document, as described in the Incorporating RE and Demand-side EE Impacts into State Plan Demonstrations TSD.
- Annual electricity generation (MWh) by fuel type and CO_2 emission levels, for each affected EGU
- ERC or emission allowance prices, when applicable

The state must also provide a clear demonstration that the state measures and/or federally enforceable emission standards informing the projected achievement of the emission performance requirements will be permanent and remain in place.

The EPA encourages participation in regional modeling efforts which are designed to allow sharing of data and help promote consistent approaches across state boundaries. A state that submits a single-state plan must consider interstate transfer of electricity across state boundaries, taking into account other states' plan types reflecting the best available information at the time of the CO_2 emission performance projection. Projections of CO_2 emission performance for multi-state plans and single-state plans that include multi-state coordination must either use a single (regional) electricity demand forecast or must document the use of electricity demand forecasts from different information sources and demonstrate how any inconsistencies between the individual electricity demand forecasts have been reconciled.

(d) *Additional projection requirements under a rate-based emission standards plan.* For an emission standards plan that applies rate-based CO_2 emission standards to individual affected EGUs, or to subcategories of affected EGUs, at a lb CO_2/MWh rate that differs from the CO_2 emission performance rates or the state's rate-based CO_2 goal in the emission guidelines, a projection of affected EGU CO_2 emission performance is required. The state must demonstrate that the weighted average CO_2 emission rate of affected EGUs, when weighted by generation (in MWh) from affected EGUs subject to the different rate-based emission standards, will be equal to or less than the CO_2 emission performance rates or the state's rate-based CO_2 emission goal during the interim and final plan performance periods.

The projection will involve an analysis of the change in generation of affected EGUs given the compliance costs and incentives under the application of different emission rate standards across affected EGUs in a state. It must accurately represent the emission standards in the plan, including the use of market-based aspects of the emission standards (if applicable), such as use of ERCs or emission allowances as compliance instruments.

In addition to the elements described in the previous section (c), the projection under this plan design must include:

- The assignment of federally enforceable emission standards for each affected EGUs;
- A projection showing how generation is expected to shift between affected EGUs and across affected EGUs and non-affected EGUs over time;
- Underlying assumptions regarding the availability and anticipated use of the MWh of electricity generation or electricity savings from eligible measures that can be issued ERCs;
- The specific calculation (or assumption) of how eligible MWh of electricity generation or savings that can be issued ERCs are being used in the projection to adjust the reported CO_2 emission rate of affected EGUs, consistent with the accounting methods for adjusting the CO_2 emission rate of an affected EGU specified in section VIII.K.1 of the emission guidelines, if applicable;
- ERC prices, if applicable;
- If a state plan provides for the ability of RE resources located in states with mass-based plans to be issued ERCs for use in adjusting the reported CO_2 emission rates of affected EGUs, consideration in the projection that such resources must meet geographic eligibility requirements, based on power purchase agreements or related documentation, consistent with the requirements at section VIII.K.1 and section VIII.L; and
- Any other applicable assumptions used in the projection.

(e) *Additional projections requirements for a state measures plan.* For a state measures plan, a projection of affected EGU CO_2 emission performance must demonstrate that the state measures, whether alone or in conjunction with any federally enforceable CO_2 emission standards for affected EGUs, will achieve the state's mass-based CO_2 goals in the emission guidelines for the interim and final periods. The projection must accurately represent individual state-enforceable measures (or bundled measures) and timing for implementation of these state measures.

A state must demonstrate that its state-enforceable measures, along with any federally enforceable CO_2 emission standards for affected EGUs included in a state plan, will achieve the state mass-based CO_2 goal. In addition to the elements described in section VIII.D.2.a.(3).(c), the state must clearly document, at a minimum:

- The assignment of federally enforceable emission standards for each affected EGUs, if applicable; and
- the individual state measures, including their projected impacts over time.

Because different types of state measures could have varying degrees of impact on reducing or avoiding CO_2 emissions from affected EGUs, and different state measures may interact with one another in terms of CO_2 emission reduction impacts, the method and tools a state uses to project CO_2 emissions impacts must have the capability to project how the combined set of state-enforceable measures are likely to impact CO_2 emissions at affected EGUs. If a state chooses to use an emission budget trading program as a mass-based state measure, for example, the state must choose an analytic method or tool that can account for and properly represent any program flexibilities that impact CO_2 emissions from affected EGUs, such as use of out-of-sector GHG offsets and cost-containment provisions. The state would show that the emissions budget trading program relied upon for the state measures plan, as well as any other state measures, ensure that the sum of emissions at all affected EGUs will be lower than or equal to the state's CO_2 emission goal in the time periods specified in these guidelines. All flexibilities must be clearly documented in the demonstration.

(4) *Monitoring, reporting and recordkeeping requirements for affected EGUs.*

The state plan submittal must specify how each emission standard is quantifiable and verifiable by describing the CO_2 emission monitoring, reporting and recordkeeping requirements for affected EGUs. The applicable monitoring, recordkeeping and reporting requirements for affected EGUs are outlined in section VIII.F.

In the June 2014 proposal, the EPA proposed that states must include in their state plans a record retention requirement for affected EGUs to maintain records for at least 10 years following the date of each occurrence, measurement, maintenance, corrective action, report or record. Commenters requested clarification of the record retention requirements for states as compared to for affected EGUs and also requested that the EPA clarify onsite versus offsite record maintenance requirements for affected EGUs. The EPA is finalizing that states must include in their plans a record retention requirement for affected EGUs of not less than 5 years following the date of each compliance period, compliance true-up period, occurrence, measurement, maintenance, corrective action, report, or record, whichever is latest. Affected EGUs must maintain each record onsite for at least 2 years after the date of the occurrence of each record and may maintain records offsite and electronically for the remaining years. Each record must be in a form suitable and readily available for expeditious review. The EPA finds that these final recordkeeping requirements are appropriate and consistent with the requirements for other CAA section 111(d) emission guidelines.

(5) *State reporting and recordkeeping requirements.*

A state plan submittal must contain the process, content and schedule for state reporting to the EPA on plan implementation and progress toward meeting the CO_2 emission performance rates or state CO_2 emission goal.

The EPA requested comments on whether full reports containing all of the report elements should only be required every 2 years and on the appropriate frequency of reporting of the different proposed elements, considering both the goals of minimizing unnecessary burdens on states and ensuring program transparency and effectiveness. Commenters recognized that different reporting frequencies may be appropriate for different types of state plans. The EPA agrees with the commenters and is finalizing state reporting requirements based on the type of plan the state chooses to adopt and implement. These state reporting requirements and reporting periods are discussed in section VIII.D.2.b (for emission standards plan types) and VIII.D.2.c (for state measures plan types). The EPA finalizes that each state report is due to the EPA no later than the July 1 following the end of each reporting period. The EPA recognizes the multiple comments received recommending extending the state report due date from July 1 to a later date or to allow the states the flexibility to propose an alternative report submittal date. The EPA is not pursuing these recommendations due to the implications of the state reports' due date and the trigger and schedule for implementation of corrective measures (for the emission standards approach) or the backstop federally enforceable emission standards (for the state measures approach). The EPA believes the July 1 deadline for states to submit reports to the EPA on plan implementation is feasible given that the information required to be included in the reports will be available per the reporting requirements for affected EGUs in state plans.

In addition to the state reporting requirements discussed in section VIII.D.2.b (for emission standards approach) and VIII.D.2.c (for state measures approach) and as discussed below, states must include in the supporting material of a final state plan submittal a timeline with all the programmatic plan milestone steps the state will take between the time of the final state plan submittal and 2022 to ensure the plan is effective as of 2022. The EPA is also finalizing a requirement that states must submit a report to the EPA in 2021 that demonstrates that the state has met the programmatic plan milestone steps that the state indicated it would take from the submittal of the final plan through the end of 2020, and that the state is on track to implement the approved state plan as of January 1, 2022. A final state plan submission must include a requirement for the state to submit this report to the EPA no later than July 1, 2021. This report will help the EPA further assist and facilitate plan implementation with states as part of an ongoing joint effort to ensure the necessary reductions are achieved.

The EPA is finalizing the requirement that submissions related to this program be submitted electronically. Specifically, this includes negative declarations, state plan submittals (including any supporting materials that are part of a state plan submittal), any plan revisions, and all reports required by the state plan. The EPA is developing an electronic system to support this requirement that can be accessed at the EPA's Central Data Exchange (CDX) (*http://www.epa.gov/cdx/*). See section VIII.E.8 for additional information on electronic submittal requirements.

In the June 2014 proposal, the EPA proposed that states must keep records, for a minimum of 20 years, of all plan components, plan requirements, plan supporting documentation and status of meeting the plan requirements, including records of all data submitted by each affected EGU used to determine compliance with its emission standards. The EPA received multiple comments recommending that the EPA reduce recordkeeping requirements due to the burden in expenditure of resources and manpower to maintain records for at least 20 years. Commenters recommended that recordkeeping requirements be reduced to 5 years consistent with emission guidelines for other existing sources.

After considering the comments received, this final rule requires that a state must keep records of all plan components, plan requirements, supporting documentation, and the status of meeting the plan requirements defined in the plan for the interim plan period from 2022–2029 (including interim steps 1, 2 and 3). After 2029, states must keep records of all information relied upon in support of any continued demonstration that the final CO_2 emission performance rates or goals are being achieved. The EPA agrees with comments that a 20-year record retention requirement could be unduly burdensome, and has reduced the length of the record retention requirement for the final rule. During the interim period, states must keep records for 10 years from the date the record is used to determine compliance with an emission standard, plan requirement, CO_2 emission performance rate or CO_2 emission goal. During the final period, states must keep records for 5 years from the date the record is used to determine compliance with an emission standard, plan requirement, CO_2 emission performance rate or CO_2 emissions goal. All records must be in a form suitable and readily available for expeditious review. States must also keep records of all data submitted by each affected EGU that was used to determine compliance with each affected EGU's emission standard, and such data must meet the requirements of the emission guidelines, except for any information that is submitted to the EPA electronically pursuant to requirements in 40 CFR part 75. If the state is adopting and implementing the state measures approach, the state must also maintain records of all data regarding implementation of each state measure and all data used to demonstrate achievement of the mass CO_2 emission goal and such data must meet the requirements of the emission guidelines. The EPA finds that these final recordkeeping requirements balance the need to maintain records while reducing the strain on state resources.

(6) *Public participation and certification of hearing on state plan.*

A robust and meaningful public participation process during state plan development is critical. For the final plan submittal, states must meaningfully engage with members of the public, including vulnerable communities, during the plan development process. This section describes how the EPA will evaluate a state plan for compliance with the minimum required elements for public participation provided in the existing implementing regulations as well as recommendations for other steps the state can take to assure robust and inclusive public participation.

The existing implementing regulations regarding public participation requirements are in 40 CFR 60.23(c)–(f). Per the implementing regulations, states must conduct a public hearing on a final state plan before such plan is adopted and submitted. State plan development can be enhanced by tapping the expertise and program experience of several state government agencies. The EPA encourages states to include utility regulators (*e.g.* the PUCs) and state energy offices as appropriate early on and throughout in the development of the state plan.[822] The EPA notes that utility regulators and state energy offices have the opportunity during the public participation processes required for state plans to provide input as well. The EPA also encourages states to conduct outreach meetings (that could include public hearings or meetings) with vulnerable communities on its initial submittal before the plan is submitted. In its final plan submittal, a state must provide certification that the state made the plan submittal available to the public and gave reasonable notice and opportunity for public comment on the state plan submittal. The state must demonstrate that the public hearing on the state plan was held only after reasonable notice, which will be considered to include, at least 30 days prior to the date of such hearing, notice given to the public by prominent advertisement announcing the date(s), time(s) and place(s) of such hearing(s). For each hearing held, a state plan submittal must include in the supporting documentation the list of witnesses and their organizational affiliations, if any, appearing at the hearing, and a brief written summary of each presentation or written submission pursuant to the requirements of the implementing regulations at 40 CFR 60.23. Additionally, the EPA recommends that states work with local municipalities, community-based organizations and the press to advertise their state public hearing(s). The EPA also encourages states to provide background information about their proposed final state plan or their initial submittal in the appropriate languages in advance of their public hearing and at their public hearing. Additionally, the EPA recommends that states provide translators and other resources at their public hearings, to ensure that all members of the public can provide oral feedback.

As previously discussed in this rule, recent studies also find that certain communities, including low-income communities and some communities of color (more specifically, populations defined jointly by ethnic/racial characteristics and geographic location) are disproportionately affected by certain climate change related impacts.[823] Also as discussed in this rule, effects from this rule can be anticipated to affect vulnerable communities in various ways. Because certain communities have a potential likelihood to be impacted by state plans, the EPA believes that the existing public participation requirements under 40 CFR 60.23 are effectuated for the purposes of this final rule by states engaging in meaningful, active ways with such communities.

In addition, certain communities whose economies are significantly dependent on coal, or whose economies may be affected by ongoing changes in the utility power and related sectors, may be particularly concerned about the final rule. The EPA encourages states to make an effort to provide background information about their proposed initial submittal and final state plans to these communities in advance of their public hearing. In particular, the EPA encourages states to engage with workers and their representatives in the utility and related sectors, including the EE sector.

The EPA notes that meaningful public involvement goes beyond the holding of a public hearing. The EPA envisions meaningful engagement to include outreach to vulnerable communities, sharing information and soliciting input on state plan development and on any accompanying assessments, such as those described in section IX. The agency uses the terms ''vulnerable'' and ''overburdened'' in referring to low-income communities, communities of color, and indigenous populations that are most affected by, and least resilient to, the impacts of climate change, and are central to our community and environmental justice considerations. In section VIII.E, the EPA provides states with examples of resources on how they can engage with vulnerable communities in a meaningful way. With respect specifically to ensuring meaningful community involvement in their public hearing(s), however, the EPA recommends that states have both a Web site and toll-free number that all stakeholders, including overburdened communities, labor unions, and others can access to get more information regarding the upcoming hearing(s) and to get their questions related to upcoming hearings answered. Furthermore, the EPA recommends that states work with their local government partners to help them in reaching out to all stakeholders, including vulnerable communities, about the upcoming public hearing(s).

(7) *Supporting documentation.*

The state plan submittal must provide supporting material and technical documentation related to applicable components of the plan submittal.

(a) *Legal authority.*

In its submittal, a state must adequately demonstrate that it has the legal authority (regulations/legislation) and funding to implement and enforce each component of the state plan submittal, including federally enforceable emission standards for affected EGUs and state measures. A state can make such a demonstration by providing supporting material related to the state's legal authority used to implement and enforce each component of the plan, such as copies of statutes, regulations, PUC orders, and any other applicable legal instruments. For states participating in a multi-state plan, the submittal(s) must also include as supporting documentation each state's necessary legal authority to implement the portion of the plan that applies within the particular state, such as copies of state regulations and statutes, including a showing that the states have

[822] While we specifically encourage state environmental agencies and utility regulators to consult here, we note that, under CAA programs, state agencies have a history of consultation with one another as appropriate.

[823] USGCRP 2014: 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, 841 pp.

the necessary authority to enter into a multi-state agreement.

(b) *Technical documentation.*

As applicable, the state submittal must include materials necessary to support the EPA's evaluation of the submittal including analytical materials used in the calculation of interim goal steps (if applicable), analytical materials used in the multi-state goal calculation (if multi-state plan), analytical materials used in projecting CO_2 emission performance that will be achieved through the plan, relevant implementation materials and any additional technical requirements and guidance the state proposes to use to implement elements of the plan.

(c) *Programmatic plan milestones and timeline.*

As part of the state plan supporting documentation, the state must include in its submittal a timeline with all the programmatic plan milestone steps the state will take between the time of the state plan submittal and 2022 to ensure the plan is effective as of January 1, 2022. The programmatic plan milestones and timeline should be appropriate to the overall state plan approach included in the state plan submittal.

(d) *Reliability.*

As discussed in more detail in section VIII.G.2, each state must demonstrate as part of its state plan submission that it has considered reliability issues while developing its plan.

b. *Additional components required for the emission standards plan type.* The EPA is finalizing requirements that a final plan submittal using the emission standards plan type must contain the following components, in addition to the components discussed in the preceding section VIII.D.2.a.

(1) *Identification of interim period emission performance rates or state goal (for 2022–2029), interim step performance rates or interim state goals (2022–2024; 2025–2027; 2028–2029) and final emission performance rates or state goal (2030 and beyond).*

The state plan submittal must indicate whether the plan is designed to meet the CO_2 emission performance rates or the state rate-based or mass-based CO_2 emission goal. As noted in the emission guidelines, the EPA is finalizing CO_2 emission performance rates for fossil fuel-fired steam generating units and for stationary combustion turbines. The EPA has translated the source category-specific CO_2 emission performance rates into equivalent state-level rate-based and mass-based CO_2 goals in order to maximize the range of choices that states will have in developing their plans. The state may choose to develop a state plan that meets the CO_2 performance rates for the two subcategories of affected EGUs or develop a plan that adopts either the rate-based or the mass-based state CO_2 emission goal provided in the emission guidelines.

Each state plan submittal must identify the emission performance rates or rate-based or mass-based CO_2 emission goal that must be achieved through the plan (expressed in numeric values, including the units of measurement, such as pounds of CO_2 per net MWh of useful energy output or tons of CO_2). The plan submittal must identify the CO_2 interim period performance rates or state goal (for 2022–2029), interim step performance rates or state goals (interim step performance rates or state goal 1 for 2022–2024; interim step performance rates or state goal 2 for 2025–2027; interim step performance rates or state goal 3 for 2028–2029) and final CO_2 emission performance rates or state goal of 2030 and beyond.

The EPA has finalized an interim performance rates or state goal for the interim period of 2022–2029 and a final performance rates or state goal to be met by 2030. For the interim period, the EPA has also finalized three interim step performance rates or state goals: interim step 1 performance rates or state goal for 2022–2024, interim step 2 performance rates or state goal for 2025–2027 and interim step 3 performance rates or state goal for 2028–2029.[824] States are free to establish different interim step performance rates or interim step state goals than those the EPA has specified in this final rule. If states choose to determine their own interim step performance rates or state goals, the state must demonstrate that the plan will still meet the interim performance rates or state goal for 2022–2029 finalized in the emission guidelines and the plan submittal must include in its supporting documentation a description of the analytic process, tools, methods, and assumptions used to make this demonstration.

For states participating in a multi-state plan with a joint goal (for interim and final periods), the individual state goals in the emission guidelines would be replaced with an equivalent multi-state goal for each period (interim and final). For a rate-based multi-state plan this would be a weighted average rate-based emission goal, derived by the participating states, by calculating a weighted average CO_2 emission rate based on the individual rate-based goals for each of the participating states and 2012 generation from affected EGUs. For a mass-based multi-state plan, the joint goal would be a sum of the individual mass-based goals of the participating states, in tons of CO_2. The plan submittal must include in its supporting documentation a description of the analytic process, tools, methods, and assumptions used to calculate the joint multi-state goal.

(2) *Identification of federally enforceable emission standards for affected EGUs.*

The state plan submittal for an emission standards plan type must include federally enforceable emission standards that apply to affected EGUs. The emission standards must meet the requirement of component (3) of this section, ''Demonstrations that each emission standard is quantifiable, non-duplicative, permanent, verifiable, and enforceable.'' The plan must identify the affected EGUs to which these standards apply. The compliance periods for each emission standard for affected EGUs, on a calendar year basis, must be as follows for the interim period: January 1, 2022–December 31, 2024; January 1, 2025–December 31, 2027; and January 1, 2028–December 31, 2029. Starting on January 1, 2030, the compliance period for each emission standard is every 2 calendar years. States can choose to set shorter compliance periods for the emission standards than the compliance periods the EPA is finalizing in this rulemaking, but cannot set longer periods. As discussed in more detail in section VIII.F, the EPA recognizes that the compliance periods provided for in this rulemaking are longer than those historically and typically specified in CAA rulemakings. The EPA determined that the longer compliance periods provided for in this rulemaking are acceptable in the context of this specific rulemaking because of the unique characteristics of this rulemaking, including that CO_2 is long-lived in the atmosphere, and this rulemaking is focused on performance standards related to those long-term impacts.

For state plans in which affected EGUs may rely upon the use of ERCs for meeting a rate-based federally enforceable emission standard, the state plan must include requirements addressing the issuance, tracking and use for compliance of ERCs consistent with the requirements in the emission guidelines. These requirements are discussed in sections VIII.K.1–2. The state plan must also demonstrate that the appropriate ERC tracking infrastructure that meets the

[824] In this action, the EPA is providing interim state goals in the form of a CO_2 emission rate (emission rate-based goal) and in the form of tonnage CO_2 emissions (mass-based goal).

requirements of the emission guidelines will be in place to administer the state plan requirements regarding ERCs and document the functionality of the tracking system. State plan requirements must include provisions to ensure that ERCs are properly tracked from issuance to submission for compliance. The state plan must also demonstrate that the MWh for which ERCs are issued are properly quantified and verified, through plan requirements for EM&V and verification that meet the requirements in the emission guidelines. EM&V requirements are discussed in section VIII.K.3. Rate-based emission standards must also include monitoring, reporting, and recordkeeping requirements for CO_2 emissions and useful energy output for affected EGUs; and related compliance demonstration requirements and mechanisms. These requirements are discussed in more detail in sections VIII.F and VIII.K.

For state plans using a mass-based emission trading program approach, the state plan must include implementation requirements that specify the emission budget and related compliance requirements and mechanisms. These requirements must include: CO_2 emission monitoring, reporting, and recordkeeping requirements for affected EGUs; provisions for state allocation of allowances; provisions for tracking of allowances, from issuance through submission for compliance; and the process for affected EGUs to demonstrate compliance (allowance ''true-up'' with reported CO_2 emissions).

(3) *Demonstration that each emission standard is quantifiable, non-duplicative, permanent, verifiable and enforceable.*

The plan submittal must demonstrate that each emission standard is quantifiable, non-duplicative, permanent, verifiable and enforceable with respect to an affected EGU, as outlined below.

An emission standard is quantifiable if it can be reliably measured, using technically sound methods, in a manner that can be replicated.[825]

An emission standard is non-duplicative with respect to an affected EGU if it is not already incorporated in another state plan, except in instances where incorporated as part of a multi-state plan. An example of a duplicative emission standard would occur, for example, where a quantified and verified MWh from a wind turbine could be applied in more than one state's CAA section 111(d) plan to adjust the reported CO_2 emission rate of an affected EGU (*e.g.,* through issuance and use of an ERC), except in the case of a multi-state plan where CO_2 emission performance is demonstrated jointly for all affected EGUs subject to the multi-state plan or where states are implementing coordinated individual plans that allow for the interstate transfer of ERCs.[826] This does not mean that measures used to comply with an emission standard cannot also be used for other purposes. For example, a MWh of electric generation from a wind turbine could be used by an electric distribution utility to comply with state RPS requirements and also be used by an affected EGU to comply with emission standard requirements under a state plan. Another example is when actions taken pursuant to CAA section 111(d) requirements can satisfy other CAA program requirements (*e.g.,* Regional Haze requirements, MATS).

An emission standard is permanent if the emission standard must be met for each applicable compliance period.

An emission standard is verifiable if adequate monitoring, recordkeeping and reporting requirements are in place to enable the state and the Administrator to independently evaluate, measure, and verify compliance with it.

An emission standard is enforceable if: (1) It represents a technically accurate limitation or requirement and the time period for the limitation or requirement is specified; (2) compliance requirements are clearly defined; (3) the entities responsible for compliance and liable for violations can be identified; and (4) each compliance activity or measure is enforceable as a practical matter in accordance with EPA guidance on practical enforceability,[827] and the Administrator, the state, and third parties maintain the ability to enforce against affected EGUs for violations and secure appropriate corrective actions, in the case of the Administrator pursuant to CAA sections 113(a)–(h), in the case of a state, pursuant to its state plan, state law or CAA section 304, as applicable, and in the case of third parties, pursuant to CAA section 304.

In developing its CAA section 111(d) plan, to ensure that the plan submittal is enforceable and in conformance with the CAA, a state should follow the EPA's prior guidance on enforceability.[828] These guidance documents serve as the foundation for the types of monitoring, reporting, and emission standards that the EPA has found can be, as a practical matter, enforced.

In the proposed regulatory text describing the enforcing measures that states must include in state plans, the EPA inadvertently excluded a required demonstration that states and other third parties can enforce against affected EGUs for violations of an emission standard included in a state plan via civil action pursuant to CAA section 304. Commenters noted the EPA's intent to require this demonstration based on statements in both the proposal preamble text and ''State Plan Considerations'' TSD[829] and based on the requirements of CAA section 304. We are finalizing a requirement for a demonstration that states and other third parties can enforce against affected EGUs for violations of an emission standard included in a state plan via civil action as part of the required plan component demonstrating enforceability. We are finalizing this requirement as a logical outgrowth of proposal preamble text, the proposal preamble citation to existing enforceability guidance documents that discuss this requirement, comments received, and the clear statutory foundation.

(4) *State reporting requirements.*

After consideration of the comments received regarding state reporting

[825] A CO_2 continuous emissions monitoring system (CEMS) is the most technically reliable method of emission measurement for EGUs. A CEMS provides a measurement method that is performance based rather than equipment specific and is verified based on NIST traceable standards. A CEMS provides a continuous measurement stream that can account for variability in the fuels and the combustion process. Reference methods have been developed to ensure that all CEMS meet the same performance criteria, which helps to ensure a level playing field and consistent, accurate data.

[826] For example, an ERC that is issued by a state under its rate-based emission standards may be used only once by an affected EGU to adjust its reported CO_2 emission rate when demonstrating compliance with the emission standards. However, an ERC issued in one state could be used by an affected EGU to demonstrate compliance with its emission standard in another state, where states are collaborating in the implementation of their individual emission trading programs through interstate transfer of ERCs, or participating in a multi-state plan with a rate-based emission trading program. These coordinated multi-state approaches are addressed in sections VIII.C.5, VIII.J.3, and VIII.K.4.

[827] The EPA guidance on enforceability includes: (1) September 23, 1987, memorandum and accompanying implementing guidance, ''Review of State Implementation Plans and Revisions for Enforceability and Legal Sufficiency,'' (2) August 5, 2004, ''Guidance on SIP Credits for Emission Reductions from Electric-Sector Energy Efficiency and Renewable Energy Measures,'' and (3) July 2012 ''Roadmap for Incorporating Energy Efficiency/Renewable Energy Policies and Programs into State and Tribal Implementation Plans, Appendix F.''

[828] See prior footnote.

[829] State Plan Considerations technical support document for the Clean Power Plan Proposed Rule: *http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule-state-plan-considerations*.

requirements, the EPA is finalizing for state plans using the emission standards approach that a state report is due to the EPA no later than the July 1 following the end of each reporting period. Within the interim period (2022–2029) the EPA is finalizing the following interim reporting periods: Interim step 1 covers the three calendar years 2022–2024, interim step 2 covers the three calendar years 2025–2027, and interim step 3 covers the two calendar years 2028–2029. A biennial state report is required starting in 2030 and beyond covering the two calendar years of each reporting period. This final reporting schedule reduces the reporting frequency for states implementing the emission standards approach and is responsive to comments received that different reporting frequencies may be appropriate for different type of state plans. The EPA believes that because of the federally enforceable emission standards that apply to affected EGUs and their corresponding monitoring, reporting and recordkeeping requirements under the emission standards plan type, a lesser frequency of reporting by the state is warranted.

The state must include in each report to the EPA the status of implementation of emission standards for affected EGUs under the state plan, including current aggregate and individual CO_2 emission performance by affected EGUs during the reporting period. The state report must include compliance demonstrations for affected EGUs and identify whether affected EGUs are on schedule to meet the applicable CO_2 emission performance rate or emission goal during the performance periods and compliance periods, as specified in the state plan. For rate-based emission trading programs, the report must also include for EPA review the state's review of the administration of their state rate-based emission trading program, as discussed in section VIII.K.2.g.

As discussed in more detail in section VIII.F, the state must include an interim performance check in the report submitted after each of the first two interim step periods. The interim performance check will compare the CO_2 emission performance level identified in the state plan for the applicable interim step period with the actual CO_2 emission performance achieved by affected EGUs during the period. In the report due to the EPA on July 1, 2030, the state must include a comparison of the actual CO_2 emission performance achieved by affected EGUs for the interim period (2022–2029) with the interim CO_2 emission performance rates or state rate-based or mass-based CO_2 interim goal, as applicable. The report due on July 1, 2030, must also include the actual CO_2 emission performance achieved by affected EGUs during the interim step 3 period (2028–2029). Starting in 2032, the biennial state report must include a final performance check to demonstrate that the affected EGUs continue to meet the final CO_2 emission performance rates or state rate-based or mass-based CO_2 goal.

For state plans that use the emission standards approach and are subject to the corrective measures provisions in the emission guidelines, if actual CO_2 emission performance (*i.e.,* the emissions or emission rate) of affected EGUs exceeds the specified level of CO_2 emission performance in the state plan by 10 percent or more during the interim step 1 or step 2 reporting periods, the state report must include a notification to the EPA that corrective measures have been triggered. The same notification is required if actual CO_2 emission performance fails to meet the specified level of emission performance in the state plan for the 8-year interim performance period or any final plan reporting period. Corrective measures are discussed in detail in section VIII.F.

c. *Additional components required for the state measures approach.*

The EPA is finalizing requirements that a final plan submittal using the state measures approach must contain the following components, in addition to the components discussed in section VIII.D.2.a. We note again that states choosing the state measures plan type must use a mass-based state goal for the state measures and any emission standards on the affected EGUs prior to the triggering of the backstop.

(1) *Identification of interim state mass goal (for 2022–2029), interim step state mass goals (2022–2024; 2025–2027; 2028–2029) and final state mass goal (2030 and beyond).*

The state plan submittal must identify the mass-based CO_2 emission goal that must be achieved through the plan (expressed in tons of CO_2). The plan submittal must identify the state CO_2 interim period goal (for 2022–2029), interim step goals (interim step goal 1 for 2022–2024; interim step goal 2 for 2025–2027; interim step goal 3 for 2028–2029) and final CO_2 emission goal of 2030 and beyond.

For each state, the EPA has finalized an interim goal for the interim period of 2022–2029 and a final goal to be met by 2030. For the interim period, the EPA has also finalized three interim step goals: Interim step 1 goal for 2022–2024, interim step 2 goal for 2025–2027 and interim step 3 goal for 2028–2029.[830] States are free to establish different interim step goals than those the EPA has specified in this final rule. If states choose to determine their own interim step goals, the state must demonstrate that it will still meet the interim goal for 2022–2029 finalized in this action and the plan submittal must include in its supporting documentation a description of the analytic process, tools, methods, and assumptions used to make this demonstration.

For states participating in a multi-state plan with a joint goal (for interim and final periods), the individual state goals in the emission guidelines would be replaced with an equivalent multi-state goal for each period (interim and final). The joint goal would be a sum of the individual mass-based goals of the participating states, in tons of CO_2. The plan submittal must include in its supporting documentation a description of the analytic process, tools, methods, and assumptions used to calculate the joint multi-state goal.

(2) *Identification of federally enforceable emission standards for affected EGUs (if applicable).*

If applicable, the state plan submittal must include any federally enforceable CO_2 emission standards that apply to affected EGUs, and demonstrate that those emission standards meet the requirements that apply in the context of an emission standards approach, discussed in the preceding section VIII.D.2.b. Specifically, the state plan submittal must demonstrate that each federally enforceable emission standard is quantifiable, non-duplicative, permanent verifiable, and enforceable. If a state measures plan type includes CO_2 emission standards that apply to affected EGUs, these emission standards must be federally enforceable.

(3) *Identification of backstop of federally enforceable emission standards.*

A state measures plan must include a backstop of federally enforceable emission standards for affected EGUs that fully achieve the interim and final CO_2 emission performance rates or the state's interim and final CO_2 emission goal if the state plan fails to achieve the intended level of CO_2 emission performance. The backstop emission standards could be based on the finalized model rule that the EPA is proposing in a separate action. For the federally enforceable backstop, the state plan submittal must identify the

[830] In this action, the EPA is providing interim state goals in the form of a CO_2 emission rate (emission rate-based goal) and in the form of tonnage CO_2 emissions (mass-based goal).

federally enforceable emission standards for affected EGUs, demonstrate that those emission standards meet the requirements that apply in the context of an emission standards approach, discussed in the preceding section, identify a schedule and trigger for implementation of the backstop that is consistent with the requirements in the emission guidelines as discussed in section VIII.C.3.b and identify all necessary state administrative and technical procedures for implementing the backstop (*e.g.* how and when the state would notify affected EGUs that the backstop has been triggered). Aspects of the backstop are discussed in detail in section VIII.C.3.b.

(4) *Identification of state measures.*

A state adopting a state measures plan type must provide as a part of the supporting documentation of its plan submittal, a description of all the state enforceable measures the state will rely upon to achieve the requisite state mass-based goal, the applicable state laws or regulations related to such measures, and identification of parties or entities implementing or complying with such state measures. The state must also include in its supporting documentation the schedule and milestones for the implementation of the state measures, showing that the measures are expected to achieve the mass-based CO_2 emission goal for the interim period (including the interim step periods) and meet the final goal by 2030. A state measures plan submittal that relies upon state measures that include RE and demand-side EE programs and projects must also demonstrate in its supporting documentation that the minimum EM&V requirements in the emission guidelines apply to those programs and projects as a matter of state law.

(5) *State reporting requirements.*

After consideration of the comments received regarding state reporting requirements, the EPA is requiring in this final rule for states using the state measures approach that an annual state report is due to the EPA no later than July 1 following the end of each calendar year during the interim period. This annual state report must include the status of implementation of federally enforceable emission standards (if applicable) and state measures, and must include a report of the periodic programmatic state measures milestones to show progress in program implementation. The programmatic state measures milestones with specific dates for achievement should be appropriate to the state measures described in the supporting documentation of the state plan submittal. The EPA believes that annual state reporting is appropriate for state measures approach due to the flexibility inherent to the approach described in section VIII.C.3 including the potential use by the state of a wider variety of state measures, responsible parties, etc. This reporting frequency will also increase the degree of certainty on plan performance for states pursuing the state measures approach.

As discussed in section VIII.F, for states using the state measures approach, the EPA is finalizing that at the end of the first two interim step periods, the state must also include in their annual report to the EPA the corresponding emission performance checks. The interim performance checks will compare the CO_2 emission performance level identified in the state plan for the applicable interim step period versus the actual CO_2 emission performance achieved by the aggregate of affected EGUs. In the report submitted to the EPA on July 1, 2030, the state must also report the actual CO_2 performance check for the interim period (2022–2029) with the interim mass-based CO_2 goal, as well as the actual CO_2 emission performance achieved by affected EGUs during the interim step 3 period (2028–2029).

Beginning with the final period, the state must submit biennial reports no later than July 1 after the end of each reporting period that includes an actual performance check to demonstrate that the state continues to meet the final state CO_2 goal.

If, at the time of the state report to the EPA, the state has not met the programmatic state measures milestones for the reporting period, or the performance check shows that the actual CO_2 emission performance of affected EGUs warrants implementation of backstop requirements,[831] the state must include in the state report a notification to the EPA that the backstop has been triggered and describe the steps taken by the state to inform the affected EGUs that the backstop has been triggered. In the event of such an exceedance under the state measures approach, the backstop federally enforceable emission standards for the affected EGUs must be effective within 18 months of the deadline for the state reporting to the EPA on plan implementation and progress toward meeting the emission performance rates or mass-based or rate-based state CO_2 emission goal. For example, if a state report due on July 1, 2025, shows that actual CO_2 emission performance of affected EGUs is deficient by 10 percent or more relative to the specified level of emission performance for 2022–2024 in the state plan, the backstop federally enforceable emission standards for affected EGUs must be effective as of January 1, 2027.

(6) *Supporting documentation.*

(a) *Demonstration that each state measure is quantifiable, non-duplicative, permanent, verifiable and enforceable.*

A state using the state measures approach, in support of its plan, must also include in the supporting documentation of the state plan submittal the state measures that are not federally enforceable emission standards, and describe how each state measure is quantifiable, non-duplicative, permanent, verifiable, and enforceable with respect to an affected entity.

A state measure is quantifiable if it can be reliably measured, using technically sound methods, in a manner that can be replicated.

A state measure is non-duplicative with respect to an affected entity if it is not already incorporated as a state measure or an emission standard in another state plan or state plan supporting material, except in instances where incorporated in another state as part of a multi-state plan. This does not mean that measures in a state measure cannot also be used for other purposes. For example actions taken pursuant to CAA section 111(d) requirements can satisfy other CAA program requirements (*e.g.,* Regional Haze requirements, MATS) and state requirements (*e.g.,* RPS).

A state measure is permanent if the state measure must be met for each applicable compliance period.

A state measure is verifiable if adequate monitoring, recordkeeping and reporting requirements are in place to enable the state to independently evaluate, measure and verify compliance with it.

A state measure is enforceable[832] if: (1) It represents a technically accurate limitation or requirement and the time period for the limitation or requirement

[831] As explained in section VIII.C.3.b, state plans subject to the backstop requirement must require the backstop to take effect if actual CO_2 emission performance by affected EGUs fails to meet the level of emission performance specified in the plan over the 8-year interim performance period (2022–2029), or for any 2-year final goal performance period. The plan also must require the backstop to take effect if actual emission performance is deficient by 10 percent or more relative to the performance levels that the state has chosen to specify in its plan for the interim step 1 period (2022–2024) or the interim step 2 period (2025–2027).

[832] Under the state measures approach, state measures are enforceable only per applicable state law.

is specified; (2) compliance requirements are clearly defined; (3) the affected entities responsible for compliance and liable for violations can be identified; and (4) each compliance activity or measure is practically enforceable in accordance with EPA guidance on practical enforceability,[833] and the state maintains the ability to enforce against affected EGUs for violations and secure appropriate corrective actions pursuant to its plan or state law.

The EPA will disapprove a state plan if the documentation is not sufficient for the EPA to be able to determine whether the state measures are expected to yield CO_2 emission reductions sufficient to result in the necessary CO_2 emission performance from affected EGUs for the mass-based state CO_2 emission goal to be achieved.

d. *Legal basis for the components.*

(1) *General legal basis.*

Under section 111(d), state plans must ''provide for the implementation and enforcement of [the] standards of performance.'' Similar language occurs elsewhere in the CAA. First, for SIPs, section 110(a)(1) requires SIPs to ''provide for implementation, maintenance, and enforcement'' of the NAAQS. However, section 110(a)(2), unlike 111(d), details a number of specific requirements for SIPs that, in part, speak exactly to how a SIP should ''provide for implementation, maintenance, and enforcement'' of the NAAQS. We note that section 111(d) provides explicitly only that the ''procedures,'' and not the substantive requirements, for section 111(d) state plans should be ''similar'' to those in section 110, and thus a substantive requirement in section 110(a)(2) is not an independent source of authority for the EPA to require the same for section 111(d) plans. However, when there is a gap for the EPA to fill in interpreting how a section 111(d) plan should ''provide for implementation and enforcement of [the] standards of performance,'' and Congress explicitly addressed a similar gap in section 110, then it may be reasonable for the EPA to fill the gap in section 111(d) using an analogous mechanism to that in section 110(a)(2), to the extent that the section 110(a)(2) requirement makes sense and is reasonable in the context of section 111(d). On the other hand, that Congress did not explicitly provide such details as are found in section 110(a)(2) indicates that Congress intended to give the EPA considerable leeway in interpreting the ambiguous phrase ''provides for implementation and enforcement of [the] standards of performance.''

For example, section 110(a)(2)(E)(i) explicitly requires states to provide necessary assurances that they have adequate personnel, funding and authority to carry out the SIP. Section 111(d), on the other hand, does not explicitly contain this requirement. Thus, there is a gap to fill with respect to this issue when the EPA interprets section 111(d)'s requirement that plans ''provide for implementation and enforcement'' of the standards of performance, and it is reasonable for the EPA to fill the gap by requiring adequate funding and authority, both because adequate funding and authority are fundamental prerequisites to adequate implementation and enforcement of any program, and because Congress has explicitly recognized this fundamental nature in the section 110 context.[834]

We note two other places where the CAA requires a state program to satisfy similar language regarding implementation and enforcement. First, section 112(l)(1) allows states to adopt and submit a program for ''implementation and enforcement'' of section 112 standards. Section 112(l)(5) further provides that the program must (among other things) have adequate authority to enforce against sources, and adequate authority and resources to implement the program. Second, section 111(c) provides that, if a state develops and submits ''adequate procedures'' for ''implementing and enforcing'' section 111(b) standards of performance for new sources in that state, the Administrator shall delegate to the state the Administrator's authority to ''implement and enforce'' those standards. The EPA has interpreted these ambiguous provisions in the EPA's ''Good Practices Manual for Delegation of NSPS and NESHAPS'' and recommended (in the context of guidance) that state programs have a number of components, such as source monitoring, recordkeeping, and reporting, in order to adequately implement and enforce section 111(b) or 112 standards. This again indicates it is reasonable for the EPA to fill a gap in section 111(d)'s language and similarly require source monitoring, recordkeeping, and reporting, as these are fundamental to implementing and enforcing standards of performance that achieve the state performance rates or goals.

Some commenters argued that states have primary authority over the content of state plans and that the EPA lacks authority to disapprove a state plan as unsatisfactory simply because it lacks one or more of these components. We disagree. The EPA has the authority to interpret the statutory language of section 111(d) and to make rules that effectuate that interpretation. With respect to the components of an approvable plan, we are interpreting the statutory phrase ''provide for implementation and enforcement'' and making rules that set out the minimum elements that are necessary for a state plan to be ''satisfactory'' in meeting this statutory requirement. This does not in any way intrude on the state's ability to decide what mix of measures should be used to achieve the necessary emission reductions. Nor does it intrude in any way on the state's ability to decide how to satisfy a component. For example, for legal authority, we are not dictating which state agencies or officials must specifically have the necessary legal authority; that is entirely up to the state so long as the fundamental requirement to have adequate legal authority to implement and enforce the plan is met.

In addition, the EPA has already determined in the 1975 implementing regulations that certain components, such as monitoring, recordkeeping, and reporting, are necessary for implementation and enforcement of section 111(d) standards of performance. 40 FR 53340, 53348/1 (Nov. 17, 1975). Thus, EPA's position here is hardly novel. The EPA notes in discussing the implementing regulations, nothing in this final rule reopens provisions or issues that were previously decided in the original promulgation of the regulations unless otherwise explicitly reopened for this rule.

(2) *Legal considerations with changes to affected EGUs.*

In the proposed rulemaking, the EPA proposed the interpretation that if an existing source is subject to a section 111(d) state plan, and then undertakes a modification or reconstruction, the source remains subject to the state plan, while also becoming subject to the modification or reconstruction

[833] The EPA's prior guidance on enforceability serves as the foundation for the types of measures that the EPA has found can be, as a practical matter, enforced. The EPA's guidance on enforceability includes: (1) September 23, 1987, memorandum and accompanying implementing guidance, ''Review of State Implementation Plans and Revisions for Enforceability and Legal Sufficiency,'' (2) August 5, 2004, ''Guidance on SIP Credits for Emission Reductions from Electric-Sector Energy Efficiency and Renewable Energy Measures,'' and (3) July 2012 ''Roadmap for Incorporating Energy Efficiency/Renewable Energy Policies and Programs into State and Tribal Implementation Plans,'' Appendix F.

[834] On the other hand, there are specific requirements in 110(a)(2) that are fundamental for SIPs, but would not make sense in the 111(d) context. For example, the specific requirement for an ambient air quality monitoring network in 110(a)(2)(B) is irrelevant in the 111(d) context.

requirements. 79 FR 34830, 34903–4. The EPA is not finalizing a position on this issue in this final rule, and is re-proposing and taking comment on this issue through the federal plan rulemaking being proposed concurrently with this action. The EPA's deferral of action on this issue does not impact states' and affected EGUs' pending obligations under this final rule relating to plan submission deadlines, as this issue concerns potential obligations or impacts after an existing source is subject to the requirements of a state plan. The EPA will propose and finalize its position on this issue through the federal plan rulemaking, which will be well in advance of the plan performance period beginning in 2022, at which point state plan obligations on existing sources are effectuated.

(3) *Legal considerations regarding design, equipment, work practice or operational standards.*

In the proposal, the EPA asked for comment on three approaches to inclusion of design, equipment, work practice and operational standards in section 111(d) plans. 79 FR 34830, 34926/3 (June 18, 2014). Under the first approach, states would be precluded from including these standards in section 111(d) plans unless the design, equipment, work practice or operational standard could be understood as a ''standard of performance'' or could be understood to ''provide for implementation and enforcement'' of standards of performance. We also asked, for the first approach, whether it was even possible, given the statutory language of 111(h), to consider a design, equipment, work practice or operational standard as a ''standard of performance.'' Under the second approach, states could include design, equipment, work practice or operational standards in the event that it could be shown a ''standard of performance'' was not feasible, as set out in section 111(h). Under the third approach, a state could include design, equipment, work practice and operational standards in a 111(d) plan without any constraints. We also asked whether, if there was legal uncertainty as to the status of these standards, the EPA should authorize states to include them in their 111(d) plans with the understanding that if the EPA's authorization were invalidated by a court, states would have to revise their plans accordingly.

The EPA is finalizing the first approach. Specifically, a state's standards of performance (in other words, either the federally enforceable backstop under the state measures approach or the emission standards under the emission standards approach) cannot consist of (in whole or part) design, equipment, work practice or operational standards. A state may include such standards in a 111(d) plan in order to implement the standards of performance. For example, a state taking a mass-based approach may include in its 111(d) plan a limit on hours of operation on a particular affected EGU, but that operational standard itself cannot substitute for a mass-based emission standard on the affected EGU.[835]

This follows from the statute. First, section 111(h)(1) authorizes the Administrator, when it is not feasible for certain reasons (specified in 111(h)(2)) to prescribe or enforce a standard of performance, to instead promulgate a design, equipment, work practice or operational standard. If a standard of performance could include design, equipment, work practice or operational standards, such authority would be unnecessary. Second, 111(h)(5) states that design, equipment, work practice or operational standards ''described in'' 111(h) shall be treated as standards of performance for the purposes of the CAA. This creates a strong inference that standards of performance otherwise should not include design, equipment, work practice, or operational standards. Finally, the general definition of ''standard of performance'' in section 302(l) is similar to the definition of ''emission limitation'' (or ''emission standard'') in section 302(k), with the exception that the definition of ''emission limitation'' explicitly includes design, equipment, work practice and operational standards, but the definition of ''standard of performance'' omits them. Thus, as with our discussion of the term ''standard of performance'' above in VIII.C.6.b, even if the general definition of ''standard of performance'' in 302(l) applies to 111(d), the omission of design, equipment, work practice, and operational standards in 302(l) confirms our interpretation that they cannot be a 111 ''standard of performance'' (except under the limited circumstances in 111(h)). We conclude that it is reasonable, and perhaps compelled, to interpret the term ''standards of performance'' in 111(d) to not include design, equipment, work practice and operational standards.

However, section 111(d) requires plans to ''provide for implementation and enforcement of [the] standards of performance.'' This language does not explicitly prohibit a plan from including design, equipment, work practice and operational standards, and allows for them to be included so long as they are understood to provide for implementation of the standards of performance. If they are included, the 111(d) plan must still be ''satisfactory'' in other respects, in particular in establishing standards of performance that are not in whole or in part design, equipment, work practice, and operational standards.

(4) *Legal basis for engagement with communities.*

As previously discussed, section 111(d)(1) requires the EPA to promulgate procedures ''similar'' to those in section 110 under which states adopt and submit 111(d) plans. Section 110(a)(1) requires states to adopt and submit implementation plans ''after reasonable notice and public hearings.'' The implementing regulations under 40 CFR 60.27 reflect similar public participation requirements with respect to section 111(d) state plans. The EPA is sensitive to the legal importance of adequate public participation in the state plan process, including public participation by affected communities. As previously discussed in this rule, recent studies also find that certain communities, including low-income communities and some communities of color, are disproportionately affected by certain climate change-related impacts. Because certain communities have a potential likelihood to be impacted by state plans for this rule, the EPA believes that the existing public participation requirements under 40 CFR 60.23 are effectuated for the purposes of this final rule by states engaging in meaningful, active ways with such communities. By requiring states to demonstrate how they have meaningfully engaged with vulnerable communities potentially impacted by state plans as part of the state plan development process, states meeting this requirement will satisfy the applicable statutory and regulatory requirements regarding public participation.

3. Components of the Federally Approved State Plan

In this action the EPA finalizes that, to be fully approved, a state plan submittal must meet the criteria and include the required components described above. The EPA will propose and take final action on each state plan submittal in the **Federal Register** and provide an opportunity for notice and comment. When a state plan submittal

[835] In particular, a state may include in its 111(d) state plan an emission standard that is reflective of the CO_2 performance resulting from operational standards the state imposes on an affected EGU.

is approved by the EPA, the EPA will codify the approved 111(d) state plan in 40 CFR part 62. The following components of the state plan submittal will become the federally enforceable state 111(d) plan:

- Federally enforceable emission standards for affected EGUs
- Federally enforceable backstop of emission standards for affected EGUs
- Implementing and enforcing measures for federally enforceable emission standards including EGU monitoring, recordkeeping and reporting requirements
- State recordkeeping and reporting requirements

E. State Plan Submittal and Approval Process and Timing

1. Overview

In this action the EPA is finalizing that state plan submittals are due on September 6, 2016, with the option of an extension to submit final state plans by September 6, 2018, which is 3 years after finalization of this rule. The compelling nature of the climate change challenge, and the need to begin promptly what will be a lengthy effort to implement the requirements of these guidelines, warrant this schedule. The EPA also believes, for reasons further described in the next section, why this schedule is achievable for states to submit final plans. We discuss the timing of state plans in more detail in this section below.

Discussed in the following sections are state plan submittal and timing, required components for initial submittals and the 2017 update, multi-state plan submissions, process for EPA review of state plans, failure to submit a plan, state plan modifications (including modifications to interim and final CO_2 emission goals), plan templates and electronic submittal, and legal bases regarding state plan process.

2. State Plan Submittal and Timing

The implementing regulations (40 CFR 60.23) require that state plans be submitted to the EPA within 9 months of promulgation of the emission guidelines, unless the EPA specifies otherwise.[836] For these 111(d) guidelines, the EPA is finalizing that each state must by September 6, 2016, either submit a final plan submittal or seek an extension to submit a final plan by September 6, 2018. In the case of a state electing to participate in the CEIP, this 2016 submittal must include a non-binding statement of intent to participate in the program. To seek an extension of the September 6, 2016 deadline until no later than September 6, 2018, a state must submit an initial submittal by September 6, 2016, that addresses three required components sufficiently to demonstrate that a state is able to undertake steps and processes necessary to timely submit a final plan by the extended date of September 6, 2018. If an extension is requested and granted, states must also submit a 2017 update by September 6, 2017, that documents the state's continued progress towards meeting the September 6, 2018 final plan submittal deadline.

In the proposal, EPA proposed a 13 month final state plan submittal deadline, with a 1 year possible extension for states submitting individual state plans and a 2 year possible extension for states submitting multi-state plans as part of a multi-state region. The EPA received substantive comment on the achievability of these proposed deadlines for state plan submittals. Multiple commenters expressed concern that due to timing of legislative cycles (some of which are every 2 years), regulatory processes, and other necessary tasks, states would find it extremely difficult to submit plans in 1 or 2 years, whether or not they were planning to submit as part of a multi-state region. The EPA agrees based on this input that a schedule shorter than 3 years will be challenging for many—though not all—states. In light of the comments received and in order to provide maximum flexibility to states while still taking timely action to reduce CO_2 emissions, in this final rule the EPA is allowing for a 2 year extension until September 6, 2018, for both individual and multi-state plans, to provide a total of 3 years for states to submit a final plan if an extension is received. Based on comments received, information the EPA has regarding steps states have already begun taking towards plan development, and extensive experience with similar state plan submission deadlines under CAA section 110 SIPs, the EPA believes states will be able to submit final plans within 3 years by September 6, 2018, in the event states are not required to submit a final plan by September 6, 2016. We address the substantive requirements of initial submittals and the 2017 update in the next section. States that receive 2-year extensions may submit the final plan earlier than September 6, 2018, if they so choose.

The EPA highlights that one purpose of the initial submittal is to encourage and potentially facilitate states to do necessary planning and engagement with stakeholders so states are able to submit an approvable final state plan by the extended deadline of September 6, 2018. Some states have well-developed existing programs and the attendant legal authority underpinning such programs to more easily meet the September 6, 2016 deadline by submitting a final plan which largely contains or relies upon such existing programs.[837] Based on comments and stakeholder feedback, however, the EPA anticipates that many states intending to develop and submit a final plan will seek the optional extension given the time it may take to undergo necessary legislative, stakeholder, and planning processes. The EPA acknowledges that the initial submittal of September 6, 2016, is not essential to the ability of states to submit final plans by September 6, 2018, so that even without this 2016 deadline, the EPA could require states to meet the 2018 deadline. Even so, this earlier date in the 3 year planning process serves as a useful ''check-in'' that provides several significant advantages. First, this earlier date provides all states an opportunity to understand what approaches other states are considering. Because there are significant benefits to regional cooperation, the EPA believes that a formal process to collect and then provide this information will help all states develop better plans. Second, because the guidelines provide significant flexibility, the ability for the EPA to provide early input to states who may be pursuing more innovative approaches will help ensure that all state plans are ultimately approvable. The EPA therefore believes the initial submittal is an appropriate means by which to offer the optional extension, and for reasons further described in section VIII.E.3, that the requirements of the initial submittal are achievable by September 6, 2016, so states will be able to develop and submit a plan that meets the requirements of the final emission guidelines and section 111(d) of the CAA by the extended date.

Additionally, some states may not submit a state plan as required by the final emission guidelines and section 111(d) of the CAA. For states that do not submit a state plan, the CAA gives the EPA express authority to implement a federal plan for sources in that state upon determination by the EPA that a state has failed to submit a state plan by the required date. For states that do not intend to submit a state plan to meet the obligations of this final rule, by promulgating a federal plan for affected EGUs in states that do not submit a plan by September 6, 2016, such affected EGUs would have a maximum of an

[836] 40 CFR 60.23(a)(1).

[837] Based on comments received, we understand that the Northeast and Mid-Atlantic states that participate in RGGI may be in this position.

additional 2 years to plan for and determine compliance strategies than had promulgation of a federal plan been predicated on states failing to submit a plan by September 6, 2018. The EPA also notes that this final rule affords states and affected EGUs with many implementation flexibilities and approaches for state plans that the EPA itself may not have the authority to implement through a federal plan. Therefore, affected EGUs subject to a federal plan promulgated for a state that refuses to submit a state plan may benefit from an additional 2 years to plan for compliance with a federal plan with potentially fewer flexibilities.

If no affected EGU is located within a state, the state must submit a letter to the EPA certifying that no such facilities exist by September 6, 2016.[838] The EPA will publish a notice in the **Federal Register** to notify the public of receipt of such letters. If an affected EGU is later found to be located in that state, the state must submit a final plan addressing such affected EGU or the EPA will determine the state has failed to submit a plan as required by the emission guidelines and CAA section 111(d), and begin the process of implementing a federal plan for that affected EGU.

In the case of a tribe that has one or more affected EGUs located in its area of Indian country, if the tribe either does not submit a CAA section 111(d) plan or does not receive EPA approval of a submitted plan, the EPA has the responsibility to establish a CAA section 111(d) plan for that area if it determines that such a plan is necessary or appropriate to protect air quality.[839] See the proposed federal plan rulemaking for further information.

The EPA notes that the current implementing regulations at 40 CFR part 60 do not specify who has the authority to make a formal submission of the state plan to the EPA for review. In order to clarify who on behalf of a state is authorized to submit an initial submittal, 2017 update, final state plan (or negative declaration, if applicable), and any revisions to an approved plan, the EPA has included a requirement in this final rule mirroring that of the requirement in 40 CFR part 51 App. V.2.1.(a) with respect to SIPs that identifies the Governor of a state as the authorized official for submitting the state plan to the EPA. If the Governor wishes to designate another responsible official the authority to submit a state plan, the EPA must be notified via letter from the Governor prior to the 2016 deadline for plan submittal so that they have the ability to submit the initial submittal or final plan in the State Plan Electronic Collection System (SPeCS). If the Governor has previously delegated authority to make CAA submittals on the Governor's behalf, a state may submit documentation of the delegation in lieu of a letter from the Governor. The letter or documentation must identify the designee to whom authority is being designated and must include the name and contact information for the designee and also identify the state plan preparers who will need access to SPeCS discussed in section VIII.E.8. A state may also submit the names of the state plan preparers via a separate letter prior to the designation letter from the Governor in order to expedite the state plan administrative process. Required contact information for the designee and preparers includes the person's title, organization and email address. The EPA recommends this information be submitted early in the state planning process to allow sufficient time for completion of SPeCS registration so that those authorized to use the system are provided access.

3. Components of an Initial Submittal and 2017 Update

As noted, states may request a 2-year extension to submit a final plan through making an initial submittal by September 6, 2016. For the extension to be granted, the EPA is finalizing that the initial submittal must address three required components sufficiently to demonstrate that a state is able to undertake steps and processes necessary to timely submit a final plan by the extended date of September 6, 2018: [840]

- An identification of final plan approach or approaches under consideration, including a description of progress made to date.
- An appropriate explanation for why the state requires additional time to submit a final plan by September 6, 2018.
- Demonstration or description of opportunity for public comment on the initial submittal and meaningful engagement with stakeholders,[841] including vulnerable communities, during the time in preparation of the initial submittal and plans for engagement during development of the final plan.

During the public comment period, multiple commenters stated that the proposed timeframe for states to submit an initial submittal was not achievable, citing, among other things, the number of decisions needed to be made by a state or states, and that the EPA needed to clarify the requirements for an initial submittal. Multiple commenters also expressed concern that the requirements for an initial submittal required final decisions to be made by states, and that the initial submittal deadline was not enough time for states to make these decisions.

It is important to note that the EPA is not requiring the adoption of any enforceable measures or final decisions in order for the state to address any of the initial submittal components by September 6, 2016. The EPA believes the absence of requiring enforceable measures to be included with the initial submittal greatly supports the ability of states intending to develop a final state plan to submit an initial submittal by September 6, 2016. States are required to submit enforceable measures supported by technically complex documentation, such as modeling, and adopted through state public participation and regulatory or legislative processes as part of SIPs under other parts of the CAA within timeframes comparable to the time the EPA is providing for initial submittals.[842]

In order to further address the commenters' concerns regarding possible ambiguity of the requirements for an initial submittal so that an extension is granted, the EPA is providing clarity regarding the required components for an initial submittal. Regarding the component that states address an appropriate explanation for an extension, the EPA proposed that appropriate explanations for seeking an extension beyond 2016 for submitting a final plan include: A state's required schedule for legislative approval and administrative rulemaking, the need for multi-state coordination in the development of an individual state plan, or the process and coordination necessary to develop a multi-state plan. In this final rule, the EPA is finalizing these as appropriate explanations for seeking an extension beyond 2016, but makes clear—as explained further below—that other appropriate explanations will be acceptable as well. It is important to note that the initial submittal does not require legislation

[838] 40 CFR 60.23(b).

[839] See 40 CFR 49.1 to 49.11.

[840] As stated previously, in the case of a state electing to participate in the CEIP, this 2016 submittal must include a non-binding statement of intent to participate in the program.

[841] Such stakeholders may include labor unions and workers that have an interest in the state plan, and communities whose economies are dependent on coal.

[842] For example, 13 states were required to submit SIP revisions sufficient to regulate GHGs under the Prevention of Significant Deterioration (PSD) permitting requirements of the CAA within either 3 weeks or 12 months in response to the EPA's SIP call. *See* ''Action To Ensure Authority To Issue Permits Under the Prevention of Significant Deterioration Program to Sources of Greenhouse Gas Emissions: Finding of Substantial Inadequacy and SIP Call'', 75 FR 77698, (December 13, 2010).

and/or regulations to be passed prior in order for the state to be granted an extension, but the initial submittal should describe any concrete steps the state has already taken on legislation and/or administrative rulemaking and detail what the remaining steps are in those processes before a final plan can be submitted. The EPA also sought comment on other circumstances for which an extension of time would be appropriate, and also whether some explanations for extensions should not be permitted. Commenters stated that states should be able to seek extensions whenever an extension can be reasonably justified, and that the EPA should take at face value states' good faith efforts by accepting any state assertion that more time is needed to develop a plan unless there is clear evidence to the contrary. The EPA believes there may be appropriate explanations states may submit in addition to the ones described in this final rule sufficient to demonstrate that a state is able to undertake steps and processes necessary to timely submit a final plan by the extended date of September 6, 2018. Given the opportunity for states to submit appropriate explanations other than the ones detailed here, the EPA believes addressing this component requiring an appropriate explanation for an extension is easily achievable by September 6, 2016.

In order to additionally clarify the required components of the initial submittal, the following are types of explanations of information states may provide as part of the initial submittal to sufficiently address each of the three required components for getting an extension:

- Details on whether a state is considering a single or multi-state plan, a plan that meets the CO_2 emission performance rates or state CO_2 rate or mass emission goal, and/or an emission standards or state measures plan type.
- A description of how the state intends to address development of the required components of the final state plan, including describing what actions have already been taken, what steps remain, and the schedule for completing those steps.
- A commitment to maintain any existing measures the state intends to rely upon for its final plan in order to achieve the necessary reductions once the performance period begins.
- Describing public participation opportunities such as stakeholder and community meetings, or public hearings, throughout the 3 year plan development process. This could also include leverage of public participation approaches that states already use to identify and engage potentially affected communities.

The EPA emphasizes the required initial submittal components are intended to provide a reasonable pathway for states to demonstrate whether they will be able to submit an approvable plan by the extended date of September 6, 2018. The EPA also anticipates that through the requirement to address these components, the initial submittal will also facilitate state planning and stakeholder engagement, particularly as one component requires the public and stakeholders to have an opportunity to comment on the initial submittal. As previously described, these components do not require final decisions to be made by states, and this is further illustrated by the clarifications on how states may meet each of the three required components. Accordingly, the EPA believes none of these components is onerous for states to address in an initial submittal by the September 6, 2016 deadline. To further underscore this point, the EPA is further explaining the clarifying examples listed above of how states may address the three required components, and highlighting the achievability of these examples for states to address through the initial submittal by September 6, 2016.

For identification of the final plan approach or approaches the state is considering, and description of progress made to date, states could identify whether the state is considering the option of the CO_2 emission performance rates, a rate-based CO_2 goal, or a mass-based CO_2 goal, and whether the state is intending to pursue a single-state or multi-state plan. Stakeholders commented that states will not be far enough along in the rule development process to have made these decisions. Commenters also stated that many state legislatures would need to pass legislation giving state environmental agencies legal authority and direction before they could begin to make decisions such as rate or mass-based approach or single or multi-state plan submittal. In order to address the commenters' concerns, the EPA wishes to clarify that state approaches identified in the initial submittal do not need to be final and/or formalized through a state legislature, and that states may opt to identify pursuit of more than one approach at the same time, or to indicate the status of the deliberation of this issue within the state.

The EPA received substantive comment regarding the potential adverse consequences for states pursuing a multi-state approach and receiving an extension until 2018, where, for various reasons, a state or states then decide(s) to pursue the single state approach. Commenters viewed this as being potentially problematic since, as proposed, a single state could only receive an extension until 2017, and if a multi-state plan effort does not work out the deadline for seeking the extension until 2017 would have passed. The EPA notes finalizing a 2 year extension that is available for any state, whether they are pursuing an individual state plan or a multi-state plan resolves the commenters' concern about conflicting extension deadlines if states involved in a multi-state effort decide not to pursue the multi-state approach. Importantly, such identification in an initial submittal does not obligate the state to then actually adopt that approach in their final plan as the EPA acknowledges that based on state processes and public input through plan development during the extended submission period, a state may end up adopting a state plan approach more suitable to the needs of that state and its affected EGUs than previously identified in the initial submittal.

States can also describe progress made to date by identifying steps already taken to address development of the final state plan, as the EPA recognizes that states in general have already taken a number of steps to prepare for state plan development to meet the obligations of this rule. For example, since proposal, states have: Begun exploring tradeoffs among various state plan approaches such as individual versus multistate coordination, increased utilization of demand-side EE and RE programs, and implementing rate-based versus mass-based programs; increased their understanding of existing state programs and policies that reduce carbon emissions; built relationships and communications between key state institutions such as environmental agencies, PUCs, governors' offices, and energy regulators; hosted public stakeholder meetings to educate and solicit input from the public; and begun discussing state processes for developing potential state plans. States may meet the first required component by describing steps such as these already undertaken.

The EPA underscores that states may easily address the first component of the initial submittal by describing such steps, and also address the second required component by identifying next steps (which may be a natural extension of these already implemented activities), and laying out a schedule for development of a final plan. States that have taken these steps would especially be able to address the component regarding an appropriate explanation for an extension as the EPA recognizes the substantial work such states have begun to put towards development of state plans, and the continuation of this work justifies additional time to complete necessary steps to result in an approvable state plan. The EPA emphasizes that for states who intend to submit a final plan and need an extension, the components of the initial submittal are not intended to require burdensome final action by states by September 6, 2016, but to identify a viable path to completing a final plan by September 6, 2018.

An initial submittal that contains a commitment to maintain any existing measures the state intends to rely upon for its final plan in order to get the necessary reductions once the performance period begins (*e.g.* RE standards and demand-side EE programs the state intends to rely upon through a state measures plan type), at least until the final plan is approved, also addresses the requirement that states provide an appropriate explanation for an extension. Given the state's request for additional time prior to putting in place enforceable measures to reduce CO_2, it would be reasonable and appropriate, and in keeping with the goals of 111(d) to ensure that any existing CO_2 reduction measures that the state intends to rely upon remain in place while the state is developing a final plan. Such commitment would demonstrate that the state is taking substantive steps towards successful development of a final plan within 3 years.

Regarding the required public participation component of the initial submittal, the EPA believes this requirement is both achievable for states to submit an initial submittal by the September 6, 2016 deadline, and provides a benefit in facilitating state plan development so that states are more likely to be able to submit a final plan within 3 years if the extension is granted. The EPA can use a comment opportunity on the initial submittal to advise the state whether aspects of the draft initial submittal and overall plan development are appropriate for purposes of meeting the requirements of the final rule so that the state will be able to procure the extension through an acceptable initial submittal and submit a final plan by the extended deadline. The EPA notes the comment period on the initial submittal is only one opportunity the EPA has to assist a state in the state plan development process. The EPA has historically worked with states throughout the state plan development process to help ensure that the state plan is approvable once submitted to the EPA, and expects this level of engagement with states to continue throughout the plan development process. This requirement will also facilitate early identification of concerns stakeholders and the public may have with aspects of a final plan the state is considering. As states have longtime and extensive experience with responding to public comments in numerous contexts, including in the context of other CAA programs such as section 110 SIP development and in permit issuance under NSR and Title V, the EPA anticipates states will be able to timely address the initial submittal public participation.

As previously discussed, because certain communities have a potential likelihood to be impacted by state plans, the EPA believes that the existing public participation requirements under 40 CFR 60.23 are effectuated for the purposes of this final rule by states engaging in meaningful, active ways with such communities. Therefore, the public participation component of the initial submittal includes meaningful engagement with vulnerable communities, throughout the state plan development process and including through the initial submittal. In order to demonstrate to the EPA that states are actively engaging with communities, states could provide in their initial submittal a summary of steps they have already taken to engage the public and how they intend to continue meaningful engagement, including with vulnerable communities, during the additional time (if an extension is granted) for development of the final plan. In addition to approaches that states already use to identify and engage potentially affected communities, the EPA encourages states to use the proximity analysis conducted for this rulemaking (which is described in section IX.A) as a tool to help them identify overburdened communities that could be potentially impacted by their plans. Other tools, such as EJ screen, can also be helpful. The EPA in its continued outreach with states during the implementation phase will also provide resources to assist them in engaging with communities. The EPA believes that through the provision of these resources states will also more easily be able to address this required component of the initial submittal regarding public engagement, including with vulnerable communities, by September 6, 2016.

In addition to the resources the EPA intends to provide to states, there are existing resources states can take advantage of to address this component as well. On the steps that states could take to engage vulnerable communities in a meaningful way, the Agency recommends that states consult the EPA's May 2015 *Guidance on Considering Environmental Justice During the Development of Regulatory Actions.* In this document, the EPA defines meaningful involvement as ensuring that ''potentially affected community members have an appropriate opportunity to participate in decisions about a proposed activity (*i.e.,* rulemaking) that may affect their environment and/or health; the population's contribution can influence the EPA's [regulatory authority's] rulemaking decisions; the concerns of all participants involved will be considered in the decision-making process; and the EPA [decision-makers] will seek out and facilitate the involvement of those potentially affected by the EPA's [or other regulatory authority's] rulemaking process.'' [843] Additionally, this guidance document also encourages those writing rules to consider the positive impacts that a rulemaking will have on communities).[844] Another resource that the EPA recommends that states consult when devising their state plans is the document ''Considering Environmental Justice in Permitting'' available on the agency's Web site.[845] Both of the resources discussed above can add to what states may already have in place to effectively engage vulnerable communities in the rulemaking process.

The EPA recommends that as part of their meaningful engagement with vulnerable communities, states work with communities to ensure that they have a clear understanding of the benefits and any potential adverse impacts that a state plan might have on their overburdened communities and that there is a clear process for states to respond to input from communities.

If a state seeks an extension by submitting an appropriate initial submittal addressing the three required components as described above by September 6, 2016, the EPA will review the submittal. If the state does not submit an initial submittal by September 6, 2016, that contains the three required components, the EPA

[843] Guidance on Considering Environmental Justice During the Development of Regulatory Actions. *http://epa.gov/environmentaljustice/resources/policy/considering-ej-in-rulemaking-guide-final.pdf.* May 2015.

[844] Ibid.

[845] Considering Environmental Justice in Permitting. *http://www.epa.gov/environmentaljustice/plan-ej/permitting.html#actions.*

will notify the state by letter, within 90 days, that the agency cannot grant the extension request based the state's initial submittal. The EPA will notify a state by letter only if the initial submittal does not address the three required components. An extension for submitting a final plan will be deemed granted if the EPA does not deny the extension request based on the initial submittal. The EPA has determined this approach is authorized by, and consistent with, 40 CFR 60.27(a) of the implementing regulations.

For states that request and receive a 2-year extension, the state must submit an update halfway through that extension, by September 6, 2017. In the proposal the EPA included a requirement regarding a 2017 check in. Because the EPA is finalizing that states are able to get a 2-year extension regardless of whether they are submitting an individual or multi state final plan, the EPA believes it appropriate to ensure through the 2017 update that the state is making continuous progress on its initial submittal and that it is on track to meet the final plan submittal deadline of September 6, 2018. The EPA will also be able to use the information provided through the 2017 update to further assist states in plan development.

The final rule requires that states address in the 2017 update the following components:

- A summary of the status with respect to required components of the final plan, including a list of which components are not yet complete.
- A commitment to a plan approach (*e.g.,* single or multi-state, rate or mass emission performance level), including draft or proposed legislation and/or regulations.
- An updated comprehensive roadmap with a schedule and milestones for completing the plan, including progress to date in developing a final plan and steps taken in furtherance of actions needed to finalize a final plan.

In order to assess whether a state is on track to submit a final plan by the 2018 extension deadline, the EPA is requiring that the 2017 update must contain a progress update on components from the initial submittal and a list of which final plan components are still not complete.

The EPA is also requiring that the 2017 update include a commitment to the type of plan approach the state will take in the final plan submittal. During the public comment period, many commenters stated that legislative action would be required to enact this final rule at the state level, and that the proposal did not provide enough time for legislative action or other regulatory actions needed for a state to be granted an extension. In order to respond to these comments, the EPA is clarifying that proposed or passed legislation or regulations are not required in the initial submittal due by September 6, 2016. While a state may indicate consideration of multiple state plan approaches in the initial submittal, the EPA is requiring that the state commit to one approach in the 2017 update. This commitment must include draft or proposed legislation or regulations that must become final at the state level prior to submitting a final plan submittal to the EPA. While commenters expressed concern with not being able to have legislation enacted in time to receive an extension until 2018, the EPA has determined that 2 years is a reasonable timeframe for a state to decide on the type of approach it will take in the final plan submittal and to draft legislation or regulations for this approach in order to timely meet the extended September 6, 2018 deadline.

4. Multi-State Plan Submittals

For states wishing to participate in a multi-state plan, the EPA is finalizing three forms of submittal that states may choose for the submittal of a multi-state plan.

First, the EPA is finalizing its proposed approach where one multi-state plan submittal is made on behalf of all participating states. The joint submittal must be signed by authorized officials for each of the states participating in the multi-state plan and would have the same legal effect as an individual submittal for each participating state. The joint submittal must adequately address plan components that apply jointly for all participating states and for each individual state in the multi-state plan, including necessary state legal authority to implement the plan, such as state regulations and statutes. Because the multi-state plan functions as a single plan, each of the required plan components (*e.g.,* plan emission goals, program implementation milestones, emission performance checks, and reporting) would be designed and implemented by the participating states on a multi-state basis.

The EPA received comments from states requesting flexibility for multi-state plan submittals. In response to these comments, the EPA is also finalizing two additional options on which it solicited comment. First, states participating in a multi-state plan can provide a single submittal—signed by authorized officials from each participating state—that addresses common plan elements. This option requires individual participating states to provide supplemental individual submittals that provide state-specific elements of the multi-state plan. The common multi-state submittal must address all relevant common plan elements and each individual participating state submittal must address all required plan components (including common plan elements, even if only through cross reference to the common plan submittal). Under this approach, the combined common submittal and each of the individual participating state submittals would constitute the multi-state plan submitted for EPA review. The joint common submittal must be signed by authorized officials for each of the states participating in the multi-state plan and would have the same legal effect as an individual submittal for each participating state.

Second, the EPA is finalizing an approach where all states participating in a multi-state plan separately make individual submittals that address all elements of the multi-state plan. These submittals would need to be materially consistent for all common plan elements that apply to all participating states, and would also address individual state-specific aspects of the multi-state plan. Each individual state plan submittal would need to address all required plan components. The EPA encourages states participating in this type of multi-state plan to use as much common material as possible to ease review of the state plans.

These approaches will provide states with flexibility in addressing contingencies where one or more states submit plan components that are not approvable. In such instances, these options simplify the EPA's approval of remaining common or individual portions of a multi-state plan and help address contingencies during plan development where a state fails to finalize its participation in a multi-state plan, with minimal disruption to the submittals of the remaining participating states. These additional submittal approaches also facilitate multi-state plans where the participating states are coordinating the implementation of their plans but are not taking on a joint multi-state emission goal for affected EGUs. For example, states may seek to engage in a multi-state approach that links rate-based or mass-based emission trading programs through appropriate authorizations (*e.g.* reciprocity agreements, or state regulations) that allow affected EGUs to use emission allowances or RE/EE credits issued in one state for compliance with an emission standard in another state.

In order to avoid a multi-state plan becoming unapprovable due to one state submitting an unapprovable portion of a multi-state plan, withdrawing from the multi-state plan, or failing to implement the multi-state plan, states may include express severability clauses if their multi-state plan is able to stand without further revision if one of the situations described above occurs. The severability clause must specify how the remainder of the multi-state plan or individual state plan would continue to function with the withdrawal of a state or states, and may also include pre-specified revisions. The EPA will evaluate the appropriateness of such a clause as part of its review of the multi-state plan submittal.

5. Process for EPA Review of State Plans

Our proposal laid out the basic steps for the EPA's review and action on submitted state plans and, at some length, discussed the required components of state plans, as further described in the preceding sections. We received a number of thoughtful and helpful comments on these issues. We are finalizing the basic requirements in this rule and are proposing, in the companion proposed federal plan under section 111(d), some additional procedural elements we believe will be helpful to states, stakeholders and the EPA moving forward.

Following the September 6, 2016 deadline for state plan submittals, the EPA will review plan submittals. For a state that submits an initial submittal by September 6, 2016, and requests an extension of the deadline for the submission of a final state plan submittal, the EPA will determine if the initial submittal meets the minimum requirements for an initial submittal. If the state does not submit an initial submittal by September 6, 2016, that contains the three required components, the EPA will notify the state by letter, within 90 days, that the agency cannot grant the extension request based the state's initial submittal. If the initial submittal meets the minimum requirements specified in the emission guidelines, the state's request for a deadline extension to submit a final plan submittal will be deemed granted, and the final plan submittal must be submitted to the EPA by no later than September 6, 2018.

After receipt of a final plan submittal, the EPA will review the plan submittal and, within 12 months, approve or disapprove the plan through a notice-and-comment rulemaking process publicized in the **Federal Register**, similar to that used for acting upon SIP submittals under section 110 of the CAA. The implementing regulations currently provide for the EPA to act on a final plan within 4 months after the deadline for submission, which is consistent with versions of section 110 prior to the 1990 Amendments to the CAA. 40 CFR 60.27(b). To be consistent with the current version of section 110, the EPA intends to adopt a timeline of 12 months to review final plan submittals upon receipt of complete submittals, as is generally consistent with the timing requirements of section 110 with respect to complete SIP submittals. Such a timeline would also provide the EPA with adequate time for review and rulemaking procedures, and ensuring an opportunity for public notice and opportunity for comment. We note, however, that we proposed this timeline for review and action on state plans in our proposal, but our proposal was specific to the timeline for state plans submitted pursuant to this rule rather than for state plans submitted under 111(d) generally.[846] We are finalizing as part of this rule that state plans submitted to meet the requirements of this rule will be reviewed and acted upon by the EPA within 12 months of submission. Because such timeline would be appropriate to be made to 111(d) state plans more generally, we are also proposing the appropriate revisions to the implementing regulations as part of the federal plan proposal for section 111(d).

In addition, while the proposal and this final rule lay out in considerable detail the required components of a state plan, the EPA believes that it would also be helpful to include in the rule a completeness determination process, similar to that used for SIP submittals under section 110, which will allow the EPA to determine whether a final plan submittal contains the components necessary to enable the EPA to determine through notice and comment rulemaking whether such submittal complies with the requirements of section 111(d). This is a procedural requirement under CAA section 110(k)(1) for SIPs, and the EPA believes this requirement is appropriate to establish under section 111(d)'s direction to the EPA to prescribe through regulations a procedure similar to that provided by section 110. However, because the EPA did not propose such regulations as part of the proposal for this action, the EPA is proposing such regulations as part of the federal plan proposal for section 111(d). The EPA notes that this preamble (in section VIII.D) and final rule lay out required components of state plans and all the requirements for a state plan submittal, and therefore states have the necessary information at this time to develop state plans. The upcoming completeness criteria will not add to or change these required components, but only add a procedural step that allows the EPA to identify whether there are absent or insufficient components in the plan submittal that would render the EPA unable to act on such submittal because it is incomplete. As we further explain in the federal plan proposal, a determination by the EPA that a plan submittal is incomplete has the effect of a state having a still-pending statutory obligation to submit a plan that meets the requirements of section 111(d).

The EPA is planning to propose an amendment to the section 111(d) implementing regulations that will add the partial approval/disapproval and conditional approval mechanisms in section 110(k)(3) and (4) to the procedure for acting on section 111(d) plans. The input the agency received in response to the proposal for these guidelines indicated that the flexibility provided by these mechanisms could be useful getting state plans in place. The EPA agrees, and is proposing to amend the implementing regulations as part of the rulemaking for the federal 111(d) plan. The EPA is not taking final action on these changes in this action.

The later timing for our action on partial approval/disapproval and conditional procedures does not create any issue with finalizing this rule. These procedural adjustments will only come into play after states have submitted their plans and the EPA is required to act on them, and we intend to finalize these procedural changes prior to September 6, 2016, when the first plan submittals would occur. Until then, the EPA believes that every plan is submitted with the intent to be fully approvable and there is no need for states to rely on the possibility of these procedures when developing their plans. Conditional approval and partial approval/disapproval should be used to deal with approvability issues that arise despite the best efforts of states and the EPA to work together to make sure a submittal in the first instance is fully approvable. The EPA plans to finalize any changes in the implementing regulations before the EPA is required to act on state submittals, so that the EPA and states will have appropriate flexibility in the plan approval process.

[846] The EPA proposed 12 months after the date required for submission of a plan or plan revision to approve or disapprove such plan or revision or each portion thereof.

6. Failure To Submit a Plan

If a state does not submit a final plan submittal by the applicable deadline, or submits a final plan the EPA determines to be incomplete, the EPA will notify the state by letter of its failure to submit. The EPA will publish a **Federal Register** notice informing the public of its finding of failure to submit. Upon a finding of failure to submit for a state, a regulatory clock will run requiring the EPA to promulgate a federal plan for such state no later than 1 year after the EPA makes the finding unless the state submits, and the EPA approves, a state plan during this time. Refer to the federal plan proposal for more details on how and when a federal plan would be triggered.

7. State Plan Modifications

a. *Modifications to an approved state plan.*

During the course of implementation of an approved state plan, a state may wish to update or alter one or more of the enforceable measures in the state plan, or replace certain existing enforceable measures with new measures. The EPA received broad support for allowing states to submit modifications to approved state plans, and we agree that this is an important aspect of this program. In this rulemaking, therefore, the EPA is finalizing that a state may revise its state plan, and states in a multi-state plan may revise their joint plan. Consistent with the timing for final plan submittals originally submitted by states, the EPA will act on state plan revisions within 12 months of a complete submittal. The EPA expects that the long plan performance timeframes in this final rule and flexibility provided to states in developing state plans will lessen the need for modifications to approved state plans.

A state may enter or exit a multi-state plan through a plan modification, with certain limitations. Multiple commenters stated that the EPA should clarify the plan modification process in such instances.

Where a state with a single-state approved plan seeks to join a multi-state plan, the state may submit a modification of its plan indicating that it is joining the multi-state plan and including the necessary plan components under the multi-state plan. The current participants of the multi-state plan will also need to submit a plan modification, to acknowledge the new state participant and to recalculate the multi-state rate-based or mass-based CO_2 goal. Functionally, both the modification of the single-state plan of the new participant and the multi-state plan of the current plan participants could be addressed through the same plan modification submittal or addressed under a plan modification submittal comparable to the alternate formats for multi-state plan submittals addressed in section VIII.E.4.

The entry or exit of a state to/from a multi-state plan involves the recalculation of the multi-state rate-based or mass-based CO_2 goal for affected EGUs in the participating states. The recalculated multi-state rate-based or mass-based CO_2 goal must take into account and ensure achievement of the individual state rate-based or mass-based CO_2 goal for any state that is joining the multi-state plan. If implementation of the individual state plan has triggered corrective measures or backstop emission standards prior to the plan modification, as described in section VIII.F.3, the modification must take into account the need to make up for any shortfall in CO_2 emission performance in the individual state plan prior to joining the multi-state plan. Where one or more states are leaving a multi-state plan through a plan modification, the process is similar and the same considerations must be taken into account in connection with the states that are leaving the multi-state plan.

As a result of these requirements and considerations, the EPA is finalizing certain requirements for multi-state plan modifications. A multi-state plan modification may be submitted to the EPA at any time. However, an approved multi-state plan modification may only take effect at the beginning of a new interim or final plan performance period. These requirements are necessary to ensure that the emission performance rates or state rate-based or mass-based CO_2 goals in the emission guidelines are achieved. In addition, such requirements for the timing of the effective date of multi-state plan modifications are necessary for coordination of the implementation of multi-state plans, especially where such plans include a multi-state emission trading approach. This approach is also consistent with the approach the EPA is proposing for the implementation of federal plan, where relevant for a state(s).

The EPA solicited comment on whether, for new projections of emission performance included in a submitted plan modification, the projection methods, tools, and assumptions used should match those used for the projection in the original demonstration of plan performance, or should be updated to reflect the latest data and assumptions, such as assumptions for current and future economic conditions and technology cost and performance. Comments received on this topic were generally supportive of allowing the use of updated data in state plan modifications, citing that states should have the ability to determine whether the original data and assumptions or updated data and assumptions are appropriate. The EPA is finalizing that new projections of emission performance, the projection methods, tools, and assumptions do not have to match those used for the projection in the original demonstration of plan performance; they can be updated to reflect the latest data and assumptions, such as assumptions for current and future economic conditions and technology cost and performance.

As discussed in more detail in section VIII.G.2, the final rule has several measures to ensure that it does not interfere with the industry's ability to maintain reliability. One such measure is that if a state cannot address a reliability issue in accordance with an approved state plan, the state can submit a request to the EPA to modify the state plan. See section VIII.G.2 for a more detailed discussion of this issue.

The EPA is not finalizing any circumstances under which a state may or may not revise its state plan, with the exception that a state may not revise its state plan in a way that results in the affected EGU or EGUs not meeting the requisite CO_2 emission performance levels.

b. *Modifications to interim and final CO_2 emission goals.*

As discussed in section VII, the final rule specifies that the state interim and final CO_2 emission goals for affected EGUs in a state may be adjusted to address changes within a state's fleet of affected EGUs. If these changes occur before a state submits its initial submittal or final plan, the state should indicate in its submittal the circumstance that necessitates the goal adjustment and the revised interim or final CO_2 emission goal. If the circumstances occur after a state has an approved plan, a state must submit a modification to its approved plan. The plan revision submittal must indicate the circumstance that necessitates the goal adjustment, the revised interim and/or final CO_2 emission goal, and the adjustments to the enforceable measures in the plan.

8. Plan Templates and Electronic Submittal

The EPA is finalizing the requirement that submissions related to this program be submitted electronically. Specifically, that includes negative declarations, state plan submittals (including any supporting materials that are part of a state plan submittal), any plan revisions, and all reports required by the state plan. The rule provides that files that are submitted to the EPA in an electronic format may be maintained by states in an electronic format. The submission of the information by the authorized official must be in a non-editable format. In addition to the non-editable version, the EPA is also requiring that all plan components designated as federally enforceable must be submitted in an editable version as well, as discussed below.

a. *Submittal of an editable version of federally enforceable plan components.*

To ensure that the EPA has the ability to identify, evaluate, merge, update and track federally enforceable plan components in a timely and comprehensive manner, the EPA is requiring states to submit an editable copy of the specific plan components in their submittals that are designated as federally enforceable, either effective upon the EPA plan approval or as a state plan backstop measure. The editable version is in addition to the non-editable version. Examples of editable file formats include Microsoft Word, Apple Pages and WordPerfect.

b. *Revisions to an approved plan.*

States shall provide the EPA with both a non-editable and editable copy of any submitted revision to existing approved federally enforceable plan components, including state plan backstop measures. The editable copy of any such submitted plan revision must indicate the changes made, if any, to the existing approved federally enforceable plan components, using a mechanism such as redline/strikethrough. This approach to identifying the changes made to the existing federally enforceable plan components is consistent with the criteria for determining the completeness of SIP submissions set forth in Section 2.1(d) of Appendix V to 40 CFR part 51.

c. *Electronic submittal.*

It is the EPA's experience that electronic submittal of information has increased the ease and efficiency of data submittal and data accessibility. The EPA is developing the SPeCS, a web accessible electronic system to support this requirement that will be accessed at the EPA's Central Data Exchange (CDX) (*http://www.epa.gov/cdx/*). The EPA will pre-register authorized officials and plan preparers in CDX. See section VIII.E.2 for additional information on the pre-registration process for authorized officials and plan preparers. Detailed instructions for accessing CDX and SPeCS will be outlined in the ''111(d) SPeCS User Guide: How to submit state 111(d) plan material to EPA'' which will be available on the EPA's Clean Power Plan Toolbox for States. The EPA will provide SPeCS training for states prior to the state plan submittal due date.

Once in CDX, SPeCS can be selected from the Active Program Service List. The preparer (*e.g.,* state representative compiling a state plan submittal) assembles the submission package. The preparer can upload files and complete electronic forms. However, the preparer may not formally submit and sign packages. Only registered authorized officials may submit and sign for the state with the exception of draft submittals. The EPA's intent is to allow submittal of draft plans or parts of plans for early EPA review prior to formal submission by the authorized official and will allow preparers, as well as authorized officials, to submit draft documents. The authorized official will be able to assemble submission packages and will be able to modify submission packages that a preparer has assembled. The key difference between the preparer and the authorized official is that the authorized official can submit and sign a package for formal EPA review using an electronic signature. In the case of a multi-state plan, each participating state's authorized official must provide an electronic signature.

The process has been designed to be compliant with the Cross-Media Electronic Reporting Rule (CROMERR), under 40 CFR part 3, which provides the legal framework for electronic reporting under all of the EPA's environmental regulations. The framework includes criteria for assuring that the electronic signature is legally associated with an electronic document for the purpose of expressing the same meaning and intention as would a handwritten signature if affixed to an equivalent paper document. In other words, the electronic signature is as equally enforceable as a paper signature. For more information on CROMERR, see the Web site: *http://www.epa.gov/cromerr/.* States who claim that a state plan submittal or supporting documentation includes confidential business information (CBI) must submit that information 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: State and Local Programs Group, MD C539–01, 4930 Old Page Rd., Durham, NC 27703.

The EPA received a number of comments on the electronic submittal of state plans. Some commenters preferred the option to submit electronically rather than the requirement to do so. In the final rule, for the reasons discussed below, the EPA is requiring electronic submittal of state plans and not allowing alternate options for plan submittal (*e.g.* paper submittal).

Requiring electronic submittal is in keeping with current trends in data availability and will result in less burden on the regulated community. Electronic submittal will facilitate two-way business communication between states and the EPA, will guide states through the submittal process to ensure submission of all required plan components, and will enable states to submit proposed plans to the EPA electronically for early EPA comments. Electronic submittal will also facilitate, expedite and promote national consistency in the EPA's review of state plans and promote transparency by providing stakeholder-specific access to updated information on state plan status and posting of plan requirements for viewing by the public, government regulators and regulated entities. The EPA recently implemented an electronic submittal process for SIPs under CAA section 110 and continues to explore opportunities to increase the ease and efficiency with which states and the regulated community can meet regulatory data submittal requirements. In summary, the EPA believes electronic submittal will be enormously beneficial in terms of improving coordination and cooperation between the EPA and its state partners in developing approvable state plans. We note, however, that there may be some circumstances where having paper copies of the plan is needed to facilitate public engagement, and encourage states to take those considerations into account.

d. *Plan templates.*

In the proposal, the EPA requested comment on the creation of templates for initial submittals and final state plan submittals. Multiple commenters requested the EPA provide state plan templates. One commenter requested templates for different plan designs (*e.g.* a mass-based trading framework, a rate-based trading framework, multi-state compliance and a utility-based portfolio approach) and for specific plan components (*e.g.* how to incorporate a state RE standard and an EE program into a state plan, how to assess the emission reductions delivered by RE and EE). The EPA has determined that the broad range of approaches states may take in preparing individual or multi-state plans makes the development of specific templates challenging and likely not useful to states. However, concurrent with this final rule, the EPA is proposing model rules for both rate- and mass-based programs in conjunction with the proposed federal plan. These effectively can serve as a template for states when preparing their state plan submittals. The EPA will continue extensive outreach to states and work closely with them on the need for additional tools and guidance to facilitate the development of approvable state plans.

9. Legal Basis Regarding State Plan Process

CAA section 111(d)(1) requires the EPA to promulgate procedures ''similar'' to those in section 110 under which states adopt and submit CAA section 111(d) plans. The EPA has interpreted this provision previously in the implementing regulations found in 40 CFR part 60 subpart B. As discussed above, the EPA intends that planned revisions to the part 60 implementing regulations will clarify (among other things) whether certain procedures are appropriate for the EPA's action on CAA section 111(d) state plans, and if so, precisely how those procedures should apply. The EPA is proposing these revisions to the CAA section 111(d) implementing regulations in the notice of proposed rulemaking for the federal plan being issued concurrently with this final rule. In this section we discuss the legal basis for procedures that the EPA is finalizing in this action: Initial submittals, extensions, and plan revisions.

First, by using the ambiguous word ''similar,'' Congress delegated authority to the EPA to determine precisely what procedures would govern 111(d) plans. ''Similar'' does not have an identical meaning as the word ''same.'' One definition of ''similar'' is ''having likeness or resemblance, especially in a general way.'' The American College Dictionary 1127 (C.L. Barnhart, ed. 1970). On the other hand, ''same'' is defined as ''alike in kind, degree, quality; that is, identical'' or ''unchanged in character.'' *Id.* at 1073.

Had Congress intended that the procedures for section 111(d) plans be indistinguishable from those in section 110, Congress knew how to say so. *See, e.g.,* 36 U.S.C. 2352(b)(2)(B) (''same procedures''). And had Congress intended that the procedures for section 111(d) plans be as close as possible to those in section 110, Congress knew how to say that. *See, e.g.,* 38 U.S.C. 4325(c) (agency ''shall ensure, *to the maximum extent practicable, that the procedures are similar* to'' certain other procedures). Therefore, Congress must have intended to give the EPA leeway to create procedures for section 111(d) state plans that somewhat vary from those in section 110, so long as the section 111(d) procedures are reasonably tied to the purpose and text of section 111(d). In other words, ''similar'' creates a gap in the statute that the EPA may reasonably fill.

a. *Initial submittals and extensions.* Initial submittals in this instance are a reasonable gap-filling procedural step. As explained in our proposal, certain aspects of section 111(d) plan development for these particular guidelines warrant our creation of this procedural step, even though section 110 does not provide for initial submittals. As explained above, though, we are not bound under section 111(d)(1) to follow exactly the same procedures.

With respect to the timing of initial submittals, final submittals, and extensions, we note that section 111 does not prescribe any particular deadlines, instead leaving it to EPA's discretion to establish ''similar'' procedures to section 110. The implementing regulations for section 111(d) plans require state plans to be submitted within 9 months of finalization of emission guidelines. Section 110(a)(1) provides that states should adopt and submit SIPs that provide for implementation, maintenance, and enforcement of the NAAQS within 3 years, or such shorter period as the Administrator may prescribe.[847] As further explained in Section VIII.E., the EPA is providing states with up to 3 years to submit a final plan under this rule, contingent upon the grant of an extension through an initial submittal due by September 6, 2016. Section 110(a)(1) does not provide any particular factors for the Administrator to consider in prescribing a shorter period. Thus, the EPA's prescription of a shorter period for either an initial submittal or a final plan submittal is consistent with the discretion granted in section 110(a)(1). We further discuss why the September 6, 2016 initial submittal deadline is reasonable in Section VIII.E., and such deadline is achievable by states seeking to submit a final plan within 3 years. We also note that section 110(b) provides for extensions of 2 years for plans to implement secondary NAAQS, that other provisions in part D provide for extensions of due dates of attainment plans in certain circumstances, and that the section 111(d) implementing regulations provide for extensions generally. We conclude, in view of the above discussion of ''similar,'' that the approach of initial submittals and extensions of due dates as proposed are reasonable procedures that, while not identical to the procedures in section 110, are still similar.

Some commenters argued that the 1-year period for initial submittals and, even assuming an extension, the additional 1- to 2-year period for final submittals were unreasonably short, particularly in light of the possibility that some state legislatures might need to act to provide adequate legal authority for these particular plans. We are not finalizing the 1-year extension for single state submittals, and we have addressed concerns about legal authority for the initial submittals by allowing states to identify remaining legislative action in those submittals.

With respect to the overall period of up to 3 years for submittals, we continue to find it reasonable and consistent with other deadlines in the CAA. First, section 110(a)(1) requires states to submit a plan for implementation, maintenance, and enforcement of new NAAQS within 3 years of promulgation of that NAAQS. This is true even if the EPA promulgates a NAAQS for a previously non-criteria pollutant. In that case, it is possible and even likely that at least some state agencies will lack statutory authority to regulate the new pollutant. Nonetheless, Congress dictated that states should submit section 110(a)(1) plans within 3 years.

Furthermore, we note that under subpart 1 of Part D of Title 1, attainment plans are generally due no later than 3 years after designation of a nonattainment area, and under other subparts of Part D, plans are due even more quickly. For example, under subpart 4, attainment plans for particulate matter are generally due 18 months after designation, and under subpart 5, the same deadline applies for attainment plans for sulfur oxides, nitrogen dioxide and lead. Developing attainment plans may or may not require states to seek additional legislative authority, but certainly in terms of complexity they are similar to section 111(d) plans for this guideline. In general, attainment plans must contain (among other things) a comprehensive inventory of sources of the relevant pollutant and its precursors (which in populated areas can be very numerous), control measures for those sources (including individualized control measures for the larger sources), and modeled demonstrations of

[847] Under this grant of authority to prescribe shorter deadlines, the EPA has in a number of occasions required SIPs to be submitted in 1 year.

attainment (which in some instances requires photochemical grid modeling). Thus, it is reasonable to have the same timeline for these section 111(d) plans as Congress generally provided for attainment plans in section 172(b).

b. *State plan modifications.*

Section 110(l) provides for states to revise their SIPs, as does 40 CFR 60.28 for section 111(d) plans. Section 110(l) also sets out a standard for revisions: It prohibits the EPA from approving a SIP revision that would interfere with any applicable requirement concerning attainment or reasonable further progress, or any other applicable requirement of the CAA. Under the existing section 111(d) implementing regulations, the Administrator will disapprove section 111(d) plan revisions as unsatisfactory when they do not meet the requirements of subpart B to part 60. See 40 CFR 60.27(c)(3). However, the implementing regulations do not set forth a substantive standard like that in section 110(l).

Section 111(d)(1) does not mention revisions (except indirectly through the reference to section 110) and, therefore, does not explicitly provide any substantive requirements for them. There is, therefore, a gap in the statute that the EPA may reasonably fill, since many stakeholders commented on the desirability of states being able to modify their plans, and the EPA agrees. It is reasonable, at a minimum, that the state plan as revised should continue to provide for implementation and enforcement of the standards of performance, and to achieve the CO_2 emission performance rates or state CO_2 emission performance goal. This is analogous to the substantive requirements of section 110(l), which as explained above for section 110(a)(2), we may consider in determining how to reasonably fill statutory gaps for section 111(d) plans.

In our proposal, we stated that certain revisions to state plans under these emission guidelines, those that revised enforceable measures for affected EGUs, should satisfy some additional conditions. First, the state should demonstrate that the plan continues to achieve the CO_2 emission performance rates or state CO_2 emission performance goal. We proposed that this demonstration might be simple for minor revisions, but for major revisions a more complete demonstration may be required. We are finalizing this proposal. As legal basis for this position, we note that a demonstration is necessary to show that a state plan provides for implementation of standards of performance that achieve the CO_2 emission performance rates or state CO_2 emission performance goal, and as explained above we can reasonably require the same of revisions.

It is also reasonable to tailor the requirements of the demonstration to the magnitude of the revision. The EPA has taken a similar approach to tailoring the requirements for a technical demonstration that, under section 110(l), a SIP revision does not interfere with any applicable requirement concerning attainment of the NAAQS. If a SIP revision does not relax the stringency of any SIP measure, then the demonstration is simple. If the SIP revision does relax the stringency of SIP measures, then a qualitative or quantitative analysis may be necessary to show non-interference, depending on the nature of the revision, the current air quality in the area, and other factors.

Finally, we proposed that revisions ''should not result in reducing the required emission performance for affected EGUs specified in the original approved plan. In other words, no 'backsliding' on overall plan emission performance through a plan modification would be allowed.'' 79 FR 34917/1. We received adverse comments that this standard did not have a basis in section 111(d). According to commenters, since the standard for EPA approval of a section 111(d) plan is whether the plan is satisfactory in establishing and providing for implementation and enforcement of standards of performance that achieve the emission performance rates or goal, the same standard should apply to revisions. In other words, the standard for revisions should be whether the plan as revised is satisfactory. We believe that our proposal was unclear as to this point, and we agree that the standard for revisions should be the same as for submittals. We have finalized this position.

F. State Plan Performance Demonstrations

This section describes state plan requirements related to compliance periods, monitoring and reporting for affected EGUs; plan performance demonstrations; consequences if the CO_2 emission performance rates or state CO_2 emission goals are not met; and out-year requirements.

1. Compliance Periods, Monitoring and Reporting Requirements for Affected EGUs

For plans that include emission standards on affected EGUs, the EGU emission standards for the interim period must have schedules of compliance for each interim step 1, 2 and 3 for the calendar years 2022–2024, 2025–2027 and 2028–2029, respectively. For the final period, EGUs must have emission standards that have schedules of compliance for each 2 calendar years starting in 2030 (*i.e.,* 2030–2031, 2032–2033, 2034–2035, etc.). If a backstop is triggered for a state measures plan, the schedule of compliance for the federally enforceable emission standards must begin no later than 18 months after the backstop is triggered and end at the end of the same compliance period. For example, if a backstop is triggered on July 1, 2025, the compliance period for the backstop emission standards must begin no later than January 1, 2027, and end on December 31, 2027. The next compliance period for the backstop emission standards would be January 1, 2028–December 31, 2029.

In the June 2014 proposal, the EPA proposed that the appropriate averaging time for any rate-based emission standard for affected EGUs be no longer than 12 months within a plan performance period and no longer than 3 years for a mass-based standard. The EPA solicited comments on longer and shorter averaging times for emission standards included in state plans. The EPA received comments stating that the proposed 12-month averaging was too short and that there was no reason why the compliance period under a rate-based plan should be different from a mass-based plan. Comments stated that a multi-year averaging period is appropriate for rate-based and mass-based plans to account for variations that can occur in a single year, allowing operators the flexibility they need to manage unforeseen events. The commenters also recommended that the final rule use discrete 3-year periods for compliance reconciliation instead of the rolling-average approach proposed.

The EPA has considered all comments received on this matter and is finalizing the compliance periods specified above, which respond to the comments by applying to both rate- and mass-based programs, providing compliance periods longer than 1 year, and establishing block compliance periods rather than a rolling average approach. We agree with comments that longer averaging periods allow for operational and seasonal variability to even out. The EPA finalizes that states can choose to set shorter compliance periods for their emission standards but none that are longer than the compliance periods the EPA is finalizing in this rulemaking. If a state chooses to set shorter compliance periods, we urge them to make efforts to be cognizant of other deadlines facing EGUs to assure that there will not be conflicts. The EPA recognizes that the compliance periods provided for in this rulemaking are longer than those historically and typically specified in CAA rulemakings. ''The time over which [the compliance standards] extend should be as short term as possible and should generally not exceed one month.'' See *e.g.,* June 13, 1989 ''Guidance on Limiting Potential to Emit in New Source Permitting'' and January 25, 1995 ''Guidance on Enforceability Requirements for Limiting Potential to Emit through SIP and § 112 Rules and General Permits.'' However, the EPA has determined that the longer compliance periods provided for in this rulemaking are acceptable in the context of this specific rulemaking because of the unique characteristics of this rulemaking, including that CO_2 is long-lived in the atmosphere, and this rulemaking is focused on performance standards related to those long-term impacts. The distinction between these unique characteristics and the EPA's general practice regarding compliance periods is bolstered by the EPA guidance on appropriate averaging periods for emission limitations in NAAQS implementation. For example, the EPA guidance has stated that in implementation of the ozone standards, which have a short averaging period, the averaging period for VOC emission limitations should be correspondingly short. See 51 FR 43857. A longer averaging period for VOC emission limitations (VOCs are one of the key precursors to ozone formation) can allow spikes in emissions that adversely impact ambient air and violate the short term ozone standards. This is precisely the opposite of the unique characteristics cited above: the long-lived persistence of CO_2 in the stratosphere and the intent of these guidelines to address the long-term impacts.

State plans must contain requirements for tracking and reporting actual plan performance during implementation, which includes reporting of CO_2 emissions from affected EGUs. Affected EGUs must comply with emissions monitoring and reporting requirements that are largely incorporated from 40 CFR part 75 monitoring and reporting requirements. The majority of affected EGUs are already familiar with the reporting requirements of part 75, and because of this, the EPA has chosen to streamline the applicable reporting requirements for affected EGUs under the state plans in the final rule. States must require all affected EGUs to monitor and report hourly CO_2 emissions and net energy output (including total net MWh output that is comprised of generation, and where applicable, useful thermal output converted to net MWhs) on a quarterly basis in accordance with 40 CFR part 75. Note that this requirement applies for all types of state plans, regardless of whether the state chooses the option of the CO_2 emission performance rates, a state rate-based CO_2 emission goal, or a state mass-based CO_2 emission goal.

In the June 2014 proposal, the EPA proposed that state plans must include monitoring, reporting and recordkeeping requirements for useful energy output from affected EGUs. Multiple commenters questioned whether gross rather than net electrical production should be reported by affected EGUs and recommended that the EPA should utilize gross rather than net generation. Many commenters recommended electricity be reported in the form used in the 111(b) rules for consistency between reporting requirements and simplification of calculation of emission limitations between new and old sources. Commenters also stated that to the extent the EPA seeks to provide guidance to states regarding its preferred monitoring and reporting procedures, the EPA should encourage states to avoid imposing additional monitoring and reporting burdens by taking advantage of the monitoring requirements that already exist to the greatest extent possible. For example, the commenters noted that the 40 CFR part 75 monitoring procedures used to comply with other programs, such as the Title IV Acid Rain Program, provide much of the data that would be needed to demonstrate compliance under the rule. Comments stated that the June 2014 proposal appeared to mandate a monitoring approach that would eliminate key flexibilities provided in the part 75 regulations, thus requiring utilities to maintain separate document collection and reporting procedures and potentially eliminating important alternative monitoring options intended to ensure representative, cost-effective monitoring approaches are available. The commenters asked the EPA to revise its proposal to make clear that the procedures established under part 75 will suffice or explain the need for any exceptions. Commenters indicated that the rule should require all affected EGUs to monitor CO_2 emissions and net hourly electric output under 40 CFR part 75, and report the data using the EPA's Emission Collection and Monitoring Plan System (ECMPS) assuring a more uniform monitoring and reporting process for all EGUs. The EPA believes that the final monitoring and reporting requirements (via ECMPS) address the issue of duplicative requirements and alleviate concern about lost flexibility raised by commenters.

2. Plan Performance Demonstrations

The state plan must include emission performance checks, and for state measures plans, periodic program implementation milestones. The state plan must provide for tracking of emission performance, and for measures to be implemented if the emission performance of affected EGUs in the state does not meet the applicable CO_2 emission performance rates or state CO_2 emission goal during a performance period.

As discussed above in section VII, the agency is finalizing CO_2 emission performance rates or state-specific CO_2 emission goals that represent emission levels to be achieved by 2030 and emission levels to be achieved over the 2022–2029 interim period, and over three interim steps of 2022–2024, 2025–2027 and 2028–2029. A state may choose to define different interim step emission levels for achieving its required 2022–2029 average performance rate. The EPA recognizes the importance of ensuring that, during the 8-year interim period (2022–2029) for the interim performance rates or interim state goal, a state is making steady progress toward achieving the required level of emission performance. For both emission standards plans and state measures plans, the final rule requires periodic checks on overall emission performance leading to corrective measures or implementation of the backstop, if necessary, as described in section VIII.F.3 below. States must demonstrate that the interim steps were achieved at the end of the first two interim step periods.

In 2032 and every 2 years thereafter, states must demonstrate that affected EGUs achieved the final performance rates or state goal on average or cumulatively, as appropriate, during each 2-year reporting period (*i.e.,* 2030–31, 2032–33, 2034–2035 etc.). The multi-year performance periods for measuring actual plan performance against the performance rates or state goals allow states some flexibility that accounts for seasonal operation of affected EGUs, and inclusion of RE and demand-side EE efforts.

For a rate-based plan, emission performance is an average CO_2 emission rate for affected EGUs representing cumulative CO_2 emissions for affected EGUs over the course of each reporting period divided by cumulative MWh energy output[848] from affected EGUs over the reporting period, with rate adjustments for qualifying measures, such as RE and demand-side EE measures. For a mass-based plan, emission performance is total tons of CO_2 emitted by affected EGUs over the reporting period.

For emission standards plans, as discussed in section VIII.D, the state must submit a report to the EPA containing the emissions performance comparison for each reporting period no later than the July 1 following the end of each reporting period (*i.e.,* by July 1, 2025; July 1, 2028; July 1, 2030; July 1, 2032; and so on). As discussed in section VIII.D, the emission comparison required in the July 1, 2030 report must compare the actual emissions from affected EGUs over the interim period (2022–2029) with the interim CO_2 emission performance rates or state CO_2 emission goal. The report is not required to include a comparison for the interim step 3 period, but must include the actual emissions from affected EGUs during the interim step 3 period.

The EPA notes that for certain types of emission standards plans, with mass-based emission standards in the form of an emission budget trading program, achievement of a state's mass-based CO_2 goal (including interim step goals and final goal) will be assessed by the EPA based on compliance by affected EGUs with their emission standards under the program, rather than CO_2 emissions during a specific interim step period or final period. This approach is limited to plans with emission budget trading programs where compliance by affected EGUs with the emission standards will ensure that, on a cumulative basis, the state interim and final mass-based CO_2 goals are achieved.[849] This approach allows for CO_2 allowance banking across plan performance periods, including from the interim period to the final period. As a result, CO_2 emissions by affected EGUs could differ from the state mass-based CO_2 goal during an individual plan performance period, but on a cumulative basis CO_2 emissions from affected EGUs would not exceed what is allowable if the interim and final CO_2 goals are achieved.

Also as discussed in section VIII.D, states that choose a state measures plan must submit an annual report no later than July 1 following the end of each calendar year in the interim period. This annual report must include the status of the implementation of programmatic state measures milestones identified in the state plan submittal. The annual report that follows the end of each reporting period (*i.e.,* 2022–2024, 2025–2027, and 2028–2029) must also include an emissions performance comparison for the reporting period, as described above for the emission standards plan. As discussed in section VIII.D, the emission comparison required in the July 1, 2030 report must compare the actual emissions from affected EGUs over the interim period (2022–2029) with the interim CO_2 emission performance rates or state CO_2 emission goal. The report is not required to include a comparison for the interim step 3 period, but must include the actual emissions from affected EGUs during the interim step 3 period. Beginning with the final period of 2030 and onward, states using a state measures plan must submit a biennial report no later than July 1 following the end of each reporting period with an emission performance comparison for each reporting period, consistent with the reporting requirements for emission standards plans.

In the June 2014 proposal, the EPA proposed that a state report is due to the EPA no later than July 1 of the year immediately following the end of each reporting period. The EPA requested comment on the appropriate frequency of reporting of the different proposed reporting elements, considering both the goals of minimizing unnecessary burdens on states and ensuring program effectiveness. In particular, the agency requested comment on whether full reports containing all of the elements should only be required every 2 years rather than annually and whether these reports should be submitted electronically, to streamline transmission.

The EPA mainly received adverse comments for requiring annual state reporting; commenters stated that this requirement was too burdensome for both states and the EPA. Commenters also requested that the EPA extend the due date of the annual report from July 1 to at least December 31. Commenters stated that because of the timing of current data collection and the need to leave time to organize and submit the reports, allowing only 6 months after the close of the year is problematic. Commenters asked that the EPA consider reducing the amount of data required if annual reporting was required.

Considering the comments received and the goals of minimizing unnecessary burdens on states and ensuring program effectiveness, the EPA has reduced the frequency of reporting of emissions data to every 3 years for the first two interim steps and every 2 years thereafter. However, the EPA is finalizing that state reports are due to the EPA no later than July 1 following the end of each reporting period. The EPA believes states can design their state plans to receive the data and information needed for these reports in a timely manner so that this requirement can be met. Furthermore, some of the state reporting requirements, such as reporting of EGU emissions, can be met through existing reporting mechanisms (ECMPS) and would not place additional burdens on states.

3. Consequences if Actual Emission Performance Does Not Meet the CO_2 Emission Performance Rates or State CO_2 Emission Goal

The EPA recognizes that, under certain scenarios, an approved state plan might fail to achieve a level of emission performance that meets the emission guidelines or the level of performance established in a state plan for an interim milestone. Despite successful implementation of certain types of plans, emissions under the plan could turn out to be higher than projected at the time of plan approval because actual conditions vary from assumptions used when projecting emission performance. Emissions also could theoretically exceed projections because affected entities under a state plan did not fulfill their responsibilities, or because the state did not fulfill its responsibilities.

The final rule specifies the consequences in the event that actual emission performance under a state plan does not meet, or is not on track to meet, the applicable interim and interim step CO_2 emission performance rates or state goals in 2022–2029, or does not meet the applicable final CO_2 emission performance rates or state CO_2 emission goal in 2030–2031 or later. The determination that a state is not on track to meet the applicable interim goal or interim step goals in 2022–2029 or the applicable final goal in 2030–2031 or later, or the CO_2 emission performance rates, will be made through the actual performance checks to be included in state reports of performance data described in section VIII.D.2.a above.

For emission standards plans, the final rule specifies that corrective measures must be enacted once triggered. Corrective measures apply

[848] For EGUs that produce both electric energy output and other useful energy output, there would also be a credit for non-electric output, expressed in MWh.

[849] Emission budget trading programs in such plans establish CO_2 emission budgets equal to or less than the state mass CO_2 goal, as specified for the interim plan performance period (including specified levels in interim steps 1 through 3) and the final 2-year plan performance periods.

only to emission standard plans in which full compliance by affected EGUs would not necessarily lead to achievement of the emission performance rates or CO_2 emission goals.[850] For such plans, corrective measures are triggered if actual CO_2 emission performance by affected EGUs is deficient by 10 percent or more relative to the specified level of emission performance in the state plan for the step 1 or step 2 interim performance periods. Corrective measures also are triggered if actual emission performance fails to meet the specified level in the plan for the 8-year interim period 2022–2029, or for any 2-year final goal performance period (beginning in 2030). In such cases, the state report must include a notification to the EPA that corrective measures have been triggered. If, in the event of such an exceedance, the EPA determines that corrective measures have been triggered and the state has failed to notify the EPA, the EPA will inform the affected EGUs that corrective measures have been triggered.[851]

When corrective measures are triggered, if the state plan does not already contain corrective measures, the state must submit to the EPA a plan revision including corrective measures that adjust requirements or add new measures. The corrective measures must both ensure future achievement of the CO_2 emission performance rates or state CO_2 emission goal and achieve additional emission reductions to offset any emission performance shortfall that occurred during a performance period. The shortfall must be made up as expeditiously as practicable. The state plan revision submission must explain how the corrective measures both make up for the shortfall and address the state plan deficiency that caused the shortfall. The state must submit the revised plan to the EPA as expeditiously as practicable and within 24 months after submitting the state report indicating the exceedance. The 24-month time period allows time to identify corrective measures and make rule changes through state regulatory processes. The EPA will then act on the plan revision within 12 months, consistent with other plan revisions and with the timing for final plan submittals originally submitted by states. The state must implement corrective measures within 6 months of the EPA's approval of a plan revision adding them.

For states using the state measures approach, the EPA is finalizing the backstop requirement as described in section VIII.C.3 of this preamble. As discussed in section VIII.D.2, the determination that a state using the state measures approach is not on track to meet the applicable interim goal or interim step goals in 2022–2029, or the applicable final goal in 2030–2031 or later, is based on checks that must be included in state reports that must be submitted annually during the interim period and biennially during the final period. The state must annually report on its progress in meeting its programmatic state measures milestones during the interim period. In addition, the state must report actual emission performance checks, similar to the requirements discussed above for emission standards plans, in 2025, 2028, 2030, and every 2 years thereafter. If, at the time of the state report to the EPA, the state did not meet the programmatic state measures milestones for the reporting period, or the performance check shows that the plan's actual CO_2 emission performance warrants implementation of backstop requirements,[852] the state must include in the state report a notification to the EPA that the backstop has been triggered. If, in the event of such an exceedance, the EPA determines that the backstop has been triggered and the state has failed to notify the EPA, the EPA will inform the affected EGUs that the backstop has been triggered.[853]

For multi-state plans, corrective measure or backstop provisions would be required for the same plan approaches for which those provisions are required in individual state plans. For multi-state plans using plan approaches to which corrective measures or backstop requirements apply, all states that are party to the multi-state plan would be subject to corrective action or backstop requirements, and requirements to make up the past CO_2 emission performance shortfall, if those requirements were triggered. This is because multi-state plans are joint plans (even if created through separate state submittals). That would not be the case for coordinated individual state plans linked through interstate ERC or emission allowance trading. In the case of coordinated individual state plans, for plan types subject to corrective measure or backstop requirements, the state where the CO_2 emission performance deficiency occurs would be required to implement corrective measures or backstop requirements for affected EGUs, as applicable, and remedy the past CO_2 emission performance shortfall.

Multiple commenters requested that corrective measures not be required in the case of a catastrophic, uncontrollable event. We recognize that there are potential system emergencies that cannot be anticipated that could cause a severe stress on the electricity system for a length of time such that the multi-year requirements in a state plan may not be achievable by certain affected EGUs without posing an otherwise unmanageable risk to reliability. We are finalizing a reliability safety valve, which includes an initial period of up to 90 days during which a reliability-critical affected EGU or EGUs will not be required to meet the emission standard established for it under the state plan but rather will meet an alternative standard. While the initial 90-day period is in use, the emissions of the affected EGU or EGUs that exceed their obligations under the approved state plan will not be counted against the state's overall goal or emission performance rate for affected EGUs and will not be counted as an exceedance that would otherwise trigger corrective measures under an emission standard plan type or an exceedance that would trigger a backstop under a state measures plan type. Use of the reliability safety valve will not alter or abrogate any other obligations under the approved state plan. After the initial period of up to 90 days, the reliability-critical affected EGU is required to continue to operate under the original state plan emission standard or an alternative standard as part of the

[850] To be specific, corrective measures requirements apply to all emission standard plan designs that do not mathematically assure that the plan performance level will be achieved when all affected EGUs are in compliance with their emission standards, regardless of electricity production and electricity mix. Corrective measures requirements apply, for example, to emission standards plans that include standards on affected EGUs that differ from the emission performance rates in the guidelines. Backstop requirements apply to state measures plans.

[851] The EPA notes that as part of the proposed federal plan rulemaking, it is proposing a regulatory mechanism to call plans in the instances of substantial inadequacy to meet applicable requirements or failure to implement an approved plan.

[852] As explained in section VIII.C.3.b., state measures plans must require the backstop to take effect if actual CO_2 emission performance fails to meet the level of emission performance specified in the plan over the 8-year interim performance period (2022–2029), or for any 2-year final goal performance period. The plan also must require the backstop to take effect if actual emission performance is deficient by 10 percent or more relative to the performance levels that the state has chosen to specify in its plan for the interim step 1 period (2022–2024) or the interim step 2 period (2025–2027).

[853] The EPA notes that as part of the proposed federal plan rulemaking, it is proposing a regulatory mechanism to call plans in the instances of substantial inadequacy to meet applicable requirements or failure to implement an approved plan.

reliability safety valve, and the state must revise its plan to accommodate changes needed to respond to ongoing reliability requirements and to ensure than any emissions excess of the applicable state goals or performance rates occurring after the initial period of up to 90 days are accounted for and offset. See section VIII.G.2.e of this preamble.

Multiple commenters supported the inclusion of strong enforcement measures for ensuring the interim and final goals are met, including the required use of corrective measures when triggered. Other commenters provided feedback as to the percentage that actual emission performance would need to exceed the level of emission performance specified in the statewide plan to trigger corrective measures. Some commenters supported the trigger that we are finalizing (actual emissions or emission rate performance that is 10 percent or more than the specified level of emission performance in the state plan for the interim step 1 or step 2 performance periods), while some recommended a lower or higher trigger.

The agency is finalizing the trigger at the level of 10 percent for the interim step 1 or step 2 performance periods. Ten percent is a reasonable level to ensure that when deficiencies in state plan performance begin to emerge, corrective measures (or backstop requirements) will be implemented promptly to avoid emissions shortfalls (or minimize the extent of shortfalls) relative to the 8-year interim goal and the final goal, which reflect the BSER. The 10 percent figure also provides latitude for a state's emission improvement trajectory during the interim period to deviate a bit from its planned path without triggering these requirements, as the state initiates or ramps up programs to meet the 8-year interim goal and final goal.

The EPA requested comment on whether the agency should promulgate a mechanism under CAA section 111(d) similar to the SIP call mechanism in CAA section 110. Under this approach, after the agency makes a finding of the plan's failure to achieve the CO_2 emission performance rates or state CO_2 emission goal during a performance period, the EPA would require the state to cure the deficiency with a new plan within a specified period of time. If the state still lacked an approved plan by the end of that time period, the EPA would have the authority to promulgate a federal plan under CAA section 111(d)(2)(A). 79 FR 34830, 34908/1–2 (June 18, 2014).

The EPA intends that planned revisions to the part 60 implementing regulations will clarify (among other things) whether the EPA has authority to call for plan revisions under section 111(d) when a state's plan is not complying with the requirements of this guideline, and if so, precisely what procedures should apply. The EPA is proposing these revisions to the 111(d) implementing regulations in the notice of proposed rulemaking for the federal plan. The EPA is not taking final action now on this issue or the related change to the implementing regulations.

a. *Legal basis for corrective measures.* The EPA discussed the concept of corrective measures in our 1992 General Preamble for the Implementation of Title I of the CAA Amendments of 1990. 57 FR 13498 (Apr. 16, 1992). The General Preamble sets out four general principles that apply to all SIPs, ''including those involving emissions trading, marketable permits and allowances.'' *Id.* at 13568. The fourth principle, accountability, means (among other things) that ''the SIP must contain means . . . to track emission changes at sources and provide for corrective action if emissions reductions are not achieved according to the plan.'' In the General Preamble, we noted that Part D of Title I explicitly provided for this in certain instances by requiring milestones and contingency measures.

Some commenters noted that the contingency measures explicitly required by part D are required to be adopted in the attainment plan and ready to implement when a milestone is not achieved or the area fails to attain the relevant NAAQS. These commenters therefore concluded that corrective measures for 111(d) plans should likewise already be adopted in the 111(d) plan and ready to implement. We disagree. Under Part D, contingency measures are not expected to fully bring the area into attainment. In fact, this would not be possible given the difficulty of predicting in advance exactly what measures would be needed to fully attain. A better analogue in Part D for the corrective measures in these guidelines is the primary way Part D addresses failure to attain: The state is required to revise its plan in various ways within a certain time in order to bring about attainment. See, *e.g.,* section 179(d). This is analogous to what we are requiring for corrective measures. Thus, part D contingency measures are unlike the corrective measures in this rule.

However, the requirement to revise an attainment plan in response to failure to attain differs somewhat from the corrective measures in these guidelines. Under these guidelines, the corrective measures must make up the difference by which the plan fell short of the goal, including any prior shortfall that had accumulated if the plan fell short of the goal in prior years. There is no corresponding requirement in attainment planning to increase the stringency of the plan by an amount that somehow makes up for any shortfall in attainment from prior years; instead the revised plan must demonstrate attainment going forward, and other more stringent requirements (such as requirements for best available control measures) may be triggered.

This distinction is the natural result of the difference between these guidelines and NAAQS attainment planning. In this case, we are finalizing guidelines representing technology-based standards for a pollutant with cumulative and long-lasting effects. If a plan falls short of a performance goal, then in effect the standards of performance in the plan have failed to reflect the BSER over the corresponding period. Due to the cumulative effects of CO_2, it is possible to remedy this failure by requiring the plan to be revised in such a way that the standards of performance in the revised plan will reflect the BSER over the cumulative plan period, and this can be done by requiring the revised plan to make up the shortfall from the previous period. In short, the flexibility that these guidelines provide should not come at the cost of allowing the standards of performance to reflect less than the BSER over the long run.[854]

Some commenters noted that 111(d) does not contain explicit provisions regarding corrective measures, and they therefore inferred that the EPA is not authorized to require them. That inference is mistaken. The requirement for 111(d) plans to ''provide for implementation and enforcement'' of the standards of performance is ambiguous and does not directly speak to whether corrective measures should or should not be required. There is therefore a gap for the EPA to fill. While the discussion above about Part D does not independently provide any authority to fill this gap, the fact that Congress created a scheme with stages of planning in Part D suggests that it would be reasonable, if appropriate, to fill this gap in 111(d) in a similar way.

In this guideline, it is appropriate for emission standards plans to fill this gap with corrective measures if triggered. There are two ways an emission standards plan can provide for implementation of standards of performance that achieve the CO_2

[854] Similar considerations apply to the requirement under the state measures approach to revise the plan to make up the shortfall.

emission performance rates or requisite state CO_2 emission performance goal. First, the state can set emission standards that necessarily achieve the performance rates or goal, even if the affected EGUs in the future vary in their relative amounts of electricity generated. Second, the state can set emission standards that are demonstrated to achieve the performance rates or goal based on assumptions about the relative amounts of electricity generated, but which may turn out to not actually achieve the goal even if all affected EGUs comply. This is analogous to an attainment plan that demonstrated attainment by the applicable attainment date, but due to unpredicted economic changes actually failed to attain. In this second case, the EPA interprets the ambiguous language ''provide for implementation . . . of standards of performance'' in the context of achieving the performance rate or emissions goal, to mean that at the time the plan is submitted it must contain some mechanism to check the progress of the plan and correct course. The EPA has determined that, for this particular rule, the minimum mechanism is the set of milestones and provisions for corrective measures specified in this rule. Indeed, not requiring corrective measures in the case of deficient plan performance would undercut the viability of state plan options other than emission standard plans with uniform rates applied to all affected EGUs within the state.

4. Out-Year Requirements: Maintaining or Improving the Level of Emission Performance Required by the Emission Guidelines

The agency is determining CO_2 emission performance rates and state CO_2 emission goals for affected EGU emission performance based on application of the BSER during specified time periods. This raises the question of whether affected EGU emission performance should be maintained at the 2030 level—or instead should be further improved—once the final CO_2 emission performance rate or state CO_2 emission goal is met in 2030. This involves questions of performance rate and goal-setting as well as questions about state planning. The EPA believes that Congress either intended the emission performance improvements required under CAA section 111(d) to be maintained or, through silence, authorized the EPA to reasonably require maintenance. Other CAA section 111(d) emission guidelines set emission limits that do not expire. Therefore, the EPA is finalizing that the level of emission performance for affected EGUs represented by the final CO_2 emission performance rates or state CO_2 emission goal must continue to be maintained in the years after 2030.

As noted above, the state plan must demonstrate that plan measures are projected to achieve the final emission performance level by 2030. In addition, the state plan must identify requirements that continue to apply after 2030 and are likely to maintain affected EGU emission performance meeting the final goal. The state plan would be considered to provide for maintenance of emission performance consistent with the final goal if the plan measures used to demonstrate projected achievement of the final goal by 2030 will continue in force and not sunset. After implementation, the state is required to compare actual plan performance against the final goal on a 2-year average basis starting in 2030, and to implement corrective measures or a backstop if triggered.

In the proposal, the EPA noted that ''CAA section 111(b)(1)(B) calls for the EPA, at least every eight years, to review and, if appropriate, revise federal standards of performance for new sources'' in order to assure regular updating of performance standards as technical advances provide technologies that are cleaner or less costly. The proposal ''requests comment on the implications of this concept, if any, for CAA section 111(d).'' 79 FR 34830, 34908/3 (June 18, 2014).

We acknowledge the obligation to review section 111(b) standards as stated. The EPA is not finalizing any position with respect to any implications of this concept for section 111(d). We are promulgating rules for section 111(d) state plans that will establish standards of performance for existing sources to which a section 111(b) standard of performance would apply if such sources were new sources, within the definition in section 111(a)(2) of ''new source.'' It is not necessary to address at this time whether subsequent review and/or appropriate revision of the corresponding section 111(b) standard of performance have any implications for review and/or revision of this rule.

a. *Legal basis for maintaining emission performance.*

In the proposal, the EPA proposed ''that the level of emission performance for affected EGUs represented by the final goal should continue to be maintained.'' The EPA explained that ''Congress either intended the emission performance improvements required under CAA section 111(d) to be permanent or, through silence, authorized the EPA to reasonably require permanence. Other CAA section 111(d) emission guidelines set emission limits to be met permanently.'' 79 FR 34830, 34908/2 (June 18, 2014). We also requested comment on whether ''we should establish BSER-based state performance goals that extend further into the future (*e.g.* beyond the proposed planning period), and if so, what those levels of improved performance should be.'' *Id.* at 34908/3.

We received adverse comment on establishing BSER-based state performance goals beyond the proposed planning period. Commenters argued that we did not have a sufficient basis at this time to determine what those future goals should be. We agree and have decided not to establish such goals. We are finalizing, though, that the level of emission performance for affected EGUs represented by the final goal should continue to be maintained, for the reasons given in our proposal and quoted above.

The general structure of the CAA supports our interpretation. Section 111(d) plans establish standards of performance that reflect the BSER, a technology-based standard. Generally speaking, in the future technology will only improve, and correspondingly the CAA does not provide explicit processes to relax technology-based standards. In contrast, the provisions in Part D of title I that address attainment of health-based standards, the NAAQS, explicitly provide that once the NAAQS are attained, emission reduction measures may be relaxed so long as the NAAQS are maintained. The absence in section 111(d) of explicit provisions for future relaxation of emission reduction measures, as compared to Part D, supports our interpretation that the emission reductions continue to be ongoing after the CO_2 emission performance rates or state CO_2 emission goals are achieved in 2030. This is consistent with our past practice for section 111(d) rules, which do not contain any provision that in the future removes or relaxes the promulgated guidelines. In light of the persistence of CO_2 as a pollutant and its long-term impacts, it is particularly critical in these guidelines to explicitly provide for continuing emission reductions.

G. Additional Considerations for State Plans

1. Consideration of a Facility's ''Remaining Useful Life'' and ''Other Factors''

This section discusses the way in which the final emission guidelines address the CAA section 111(d)(1) provision requiring the Administrator, in promulgating 111(d) regulations, to ''permit the State in applying a standard of performance to any particular source under a [111(d)] plan . . . to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies.''

The final guidelines permit a state, in developing its state plan, to fully consider and take into account the remaining useful life of an affected EGU and other factors in establishing the requirements that apply to that EGU, as discussed further below. Therefore, consideration of facility-specific factors and in particular, remaining useful life, does not justify a state making further adjustments to the performance rates or aggregate emission goal that the guidelines define for affected EGUs in a state and that must be achieved by the state plan. Thus, these guidelines do not provide for states to make additional goal adjustments based on remaining useful life and other facility-specific factors because they can fully consider these factors in designing their plans.

a. *Statutory and regulatory backdrop.*

This section describes the statutory and existing regulatory background concerning facility-specific considerations in implementation of section 111(d).

Section 111(d)(1)(A) requires states to submit a plan that ''establishes standards of performance'' for existing sources. Under section 111(d)(1)(B), the plan must also ''provide for implementation and enforcement of such standards of performance.'' Finally, the last sentence of section 111(d)(1) provides: ''Regulations of the Administrator under this paragraph shall permit the State in applying a standard of performance to any particular source under a plan submitted under this paragraph to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies.''

The EPA's 1975 implementing regulations[855] addressed a number of facility-specific factors that might affect requirements for an existing source under section 111(d). Those regulations provide that for designated pollutants, standards of performance in state plans must be as stringent as the EPA's emission guidelines. Deviation from the standard might be appropriate where the state demonstrates with respect to a specific facility (or class of facilities):

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

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

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

This provision was amended in 1995 (60 FR 65387, December 19, 1995), and is now prefaced with the language ''Unless otherwise specified in the applicable subpart on a case-by-case basis for particular designated facilities or classes of facilities.'' 40 CFR 60.24(f).

b. *Our proposal regarding the implementing regulations.*

Our proposal stated that the reference to ''[u]nreasonable cost of control resulting from plant age'' in 60.24(f) ''implements'' the statutory provision on remaining useful life. We also stated that the implementing regulations ''provide the EPA's default structure for implementing the remaining useful life provision of CAA section 111(d).'' We noted that the prefatory language ''unless otherwise specified in the applicable subpart'' gives the EPA discretion to alter the extent to which the implementing rules applied if appropriate for a particular source category and guidelines. We requested comment on our analysis of the existing implementing regulations and any implications for our regulatory text in respect to how these guidelines relate to those regulations.

Commenters stated, among other things, that the sentence concerning ''remaining useful life'' was added in the 1977 CAA Amendments and that therefore it could not be said that provisions from the 1975 implementing regulations ''implement'' the sentence. The EPA does not think as a general matter that it is necessarily impossible that a pre-statutory amendment rule could continue to serve as a reasonable implementation of a post-statutory amendment provision. However, we also think it is appropriate, as we suggested in the June 2014 proposal, to specify in the applicable subpart for these guidelines that the provisions in 60.24(f) should not apply to the class of facilities covered by these guidelines. As a result, regardless of whether the implementing regulations appropriately implement the ''remaining useful life'' provision in general, the relevant consideration is that, as we now explain, these particular guidelines ''permit the State in applying a standard of performance to any particular source under a plan submitted under this paragraph to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies.''

c. *How these emission guidelines permit states to consider remaining useful life and other facility-specific factors.*

The EPA notes that, in general, the implementing regulation provisions for remaining useful life and other facility-specific factors are relevant for emission guidelines in which the EPA specifies a presumptive standard of performance that must be fully and directly implemented by each individual existing source within a specified source category. Such guidelines are similar to a CAA section 111(b) standard in their form. For example, the EPA emission guidelines for sulfuric acid plants, phosphate fertilizer plants, primary aluminum plants, Kraft pulp plants, and municipal solid waste landfills specify emission limits for sources.[856] In the case of such emission guidelines, some individual sources, by virtue of their age or other unique circumstances, may warrant special accommodation.

In these final guidelines for state plans to limit CO_2 from affected EGUs, however, the agency does not specify presumptive performance rates that each individual EGU is to achieve in the absence of trading. Instead, these guidelines provide collective performance rates for two classes of affected EGUs (steam generating units and stationary combustion turbines), and give states the alternative of developing plans to achieve a state emission goal for the collective group of all affected EGUs in a state. Providing states with the ability to consider facility-specific factors such as remaining useful life in designing their state plans is one of the fundamental reasons that the EPA designed the final rule in this way. In addition, the significant revisions since proposal to address achievability concerns (*e.g.,* moving the start date from 2020 to 2022, and other changes in interim and final state goals summarized in the next section) will help to ensure that states in practice can consider remaining useful life and other facility-specific factors in setting EGU requirements. Of course, EGUs vary considerably in age, so remaining useful life is potentially

[855] 40 FR 53340 (Nov. 17, 1975).

[856] See ''Phosphate Fertilizer Plants; Final Guideline Document Availability,'' 42 FR 12022 (Mar. 1, 1977); ''Standards of Performance for New Stationary Sources; Emission Guideline for Sulfuric Acid Mist,'' 42 FR 55796 (Oct. 18, 1977); ''Kraft Pulp Mills, Notice of Availability of Final Guideline Document,'' 44 FR 29828 (May 22, 1979); ''Primary Aluminum Plants; Availability of Final Guideline Document,'' 45 FR 26294 (Apr. 17, 1980); ''Standards of Performance for New Stationary Sources and Guidelines for Control of Existing Sources: Municipal Solid Waste Landfills, Final Rule,'' 61 FR 9905 (Mar. 12, 1996).

relevant to regulation of some units and not others.

The guidelines capitalize on the inherent flexibility offered by the CO_2 emission performance rates and by the state CO_2 emission goals approach, allowing states flexibility on the form of the EGU standards that they include in CAA section 111(d) plans. A state could select a form of standards (*e.g.,* marketable credits or permits, retirement of certain older facilities after their useful life, etc.) that avoids or diminishes concerns about facility-specific factors such as remaining useful life. If a state adopted the CO_2 emission performance rates for fossil fuel-fired electric utility steam generating units and stationary combustion turbines in conjunction with rate-based trading, though, the state would be taking remaining useful life into consideration by allowing affected EGUs to comply using ERCs. In effect, under a trading program with repeating compliance periods, a facility with a short remaining useful life has a total outlay that is proportionately smaller than a facility with a long remaining useful life, simply because the first facility would need to comply for fewer compliance periods and would need proportionately fewer ERCs than the second facility. Buying ERCs would avoid excessive up-front capital expenditures that might be unreasonable for a facility with a short remaining useful life, and would reduce the potential for stranded assets.

In addition to providing states with flexibility on the form of the standards of performance in their plans, the guidelines leave to each state the design of the specific requirements that fall on each affected EGU in applying those standards. To the extent that an emission standard that a state may wish to adopt for affected EGUs raises facility-specific issues, the state may make adjustments to a particular facility's requirements on facility-specific grounds, so long as any such adjustments are reflected (along with any necessary compensating emission reductions to meet the state goal) in the state's CAA section 111(d) plan submission.

Finally, we note that these guidelines permit states to use a rate or mass CO_2 emission goal, and that each of these pathways allow states multiple design choices. Under either pathway states can take into consideration remaining useful life and seek to avoid stranded assets.

The EPA believes that this approach to permitting states to consider remaining useful life is appropriate because it reflects, and is compatible with, the interconnected nature of the electricity system.

Although this discussion emphasizes state flexibility on plan design, it is important to note that the main intended beneficiaries of state flexibility are the affected EGUs themselves. As a key case in point, the EPA has endeavored to craft the final guidelines to support and facilitate state plans that include trading systems, including interstate trading systems that can help EGUs continue to operate with the flexibility that they currently enjoy on regional grid levels.

Trading can provide affected EGUs that have a limited remaining useful life with the flexibility to comply through purchasing allowances or ERCs, thereby avoiding major capital expenditures that would create long-term debt. By buying allowances or ERCs, affected EGUs with a limited remaining useful life contribute to achieving emission reductions from the source category during the years that they operate. During its lifetime, a facility with a short remaining useful life will need fewer total credits or allowances than an otherwise comparable facility with a long remaining useful life, but the annualized cost to the two facilities is the same.[857]

In part to help states address remaining useful life considerations, the final guidelines facilitate state plans that employ trading in multiple ways:

- By allowing trading under emission standards plans and state measures plans, and under rate-based plans and mass-based plans;
- By defining national EGU performance rates that make it easier for states to set up rate-based trading regimes that allow for interstate trading of ERCs;
- By clearly defining the requirements for mass-based and rate-based trading systems to ensure their integrity; and
- By providing information on potential allocation approaches for mass-based trading.

In addition, the EPA is separately proposing model trading rules for rate-based and mass-based trading to assist states with design of these programs in the section 111(d) context.

d. *Why remaining useful life and other facility-specific factors do not warrant adjustments in the guidelines' performance rates and state goals.*

Under the final guidelines, remaining useful life and other facility-specific considerations do not provide a basis for adjusting the CO_2 emission performance rates, or the state's rate-based or mass-based CO_2 emission goals, nor do they affect the state's obligation to develop and submit an approvable CAA section 111(d) plan that adopts the CO_2 emission performance rates or achieves the goal by the applicable deadline. After considering public comments discussed below and in the response to comments document, the EPA has retained this aspect of the proposed rule for the reasons described below.

As noted above, the final guidelines provide aggregate emission goals for affected EGUs in each state, in addition to the CO_2 emission performance rates. The guidelines also reflect a number of changes from proposal to address concerns about achievability of proposed state goals that were raised in public comments, many of which were explicitly prompted by consideration of the remaining useful life issue. The result is to afford states with broad flexibility to design requirements for affected EGUs to achieve the CO_2 emission performance rates or state CO_2 emission goals in ways that avoid requiring major capital expenditures, or imposing unreasonable costs, on those affected EGUs that have a limited remaining useful life. State plans may use any combination of the emissions reduction methods represented by the building blocks, and may also choose to employ emission reduction methods that were not assumed in calculating state goals.

To be more specific, the EPA notes that a state is not required to achieve the same level of emission reductions with respect to any one building block as assumed in the EPA's BSER analysis. A state may use any combination of measures, including those not specifically factored into the BSER by the EPA. The EPA has estimated reasonable rather than maximum possible implementation levels for each building block in order to establish EGU emission rates and state goals that are achievable while allowing states to take advantage of the flexibility to pursue some building blocks more aggressively, and others less aggressively, than is reflected in the agency's computations, according to each state's needs and preferences. The guidelines provide further flexibility by allowing state plans to use emission reduction methods not reflected in the BSER. A description of multiple emission reduction methods is provided in sections VIII.I–K.

e. *Response to key comments on remaining useful life.*

In response to the proposed guidelines, some commenters said that the proposed state goals were

[857] Trading of course has other benefits beyond helping to address remaining useful life concerns. For example, trading can lower costs of achieving a given level of emission reduction and can provide economic incentives for innovation and development of cleaner technologies.

unachievable and therefore too stringent to provide states, as a practical matter, with the flexibility to consider remaining useful life for individual units. These commenters said the result would be premature retirements and stranded assets.

In the final guidelines, the EPA has addressed the comments about lack of practical flexibility to consider remaining useful life by revising key elements of the guidelines in ways that will ensure that the CO_2 emission performance rates and state CO_2 emission goals are achievable considering cost. At the same time, the final guidelines maintain the broad flexibility of each state to design its own compliance pathway, taking into account any facility-level concerns—including remaining useful life—in designing EGU requirements.

The changes to the BSER and goal-setting methodologies include:

- Starting the interim goal period in 2022 rather than 2020, which allows more lead time for states and regulated entities and helps to ensure that the interim goal is achievable
- Revising the goal-setting formula and the state goals themselves
- Updating analyses of achievable levels of improvement through the building blocks that together represent the BSER, while keeping them at reasonable, rather than maximum, levels (thus creating headroom which can, and is intended to, help to accommodate the range of ages of different facilities)
- Providing an explicit phase-in schedule for meeting the revised interim goals, while also allowing a state the option of choosing its own emission reduction trajectory

The final guidelines also contain changes to avoid certain inconsistencies between the goal-setting methodology and accounting of reductions under state plans that could have made state goals less achievable for some states.

Together, the changes described above help to ensure that the CO_2 emission performance rates and state CO_2 emission goals established in the final guidelines are achievable, and leave states with the practical ability to issue rules that take into account the remaining useful life of affected EGU.

As explained in the Legal Memorandum accompanying this rule, the EPA believes that Congress intended the remaining useful life provision to provide a mechanism for states to avoid the imposition of unreasonable retrofit costs on existing sources with relatively short remaining useful lives, a scenario that could result in stranded assets. However, commenters on the proposed rule raised a different stranded assets concern not primarily related to retrofit costs—a concern that the proposed rule could cause changes in economic competitiveness of particular EGUs that would prompt their retirement before the end of their economically useful lives. These commenters said the proposed state goals were so stringent that states would have no choice but to adopt requirements that would result in retirements of coal-fired capacity that had been built relatively recently or had recently made pollution control investments. In response to these comments, the EPA has conducted a stranded assets analysis which demonstrates that the CO_2 emission performance rates and state goals in the final guidelines provide sufficient flexibility to states to address stranded asset concerns. The EPA shares the goal of minimizing stranded assets. Although nothing in section 111(d) explicitly bars a guideline that results in some facilities becoming uneconomic before the end of their useful lives, the EPA nonetheless has striven to design the guidelines so as to give states flexibility to develop plans that include, for example, differential treatment of affected EGUs or opportunities to rely on emissions trading, to allow power companies to recover their investments in generation units.

For purposes of the stranded assets analysis, the EPA considered a potential ‘‘stranded asset’’ to be an investment in a coal-fired EGU (or in a capital-intensive pollution control installed at such an EGU) that retires before it is fully depreciated. Book life is the period over which long-lived assets are depreciated for financial reporting purposes. The agency estimated typical book life by researching financial statements of utility and merchant generation companies in filings to the Securities and Exchange Commission. The agency estimated the book life of coal-fired EGUs to be 40 years, and assumed a 20-year book life for pollution control retrofits. The book life of coal-fired EGUs (coal steam and IGCC) is twice as long as the debt life and the depreciation schedule used for federal tax purposes. Although the book life for environmental retrofits is often 15 years, the agency conservatively assumed 20 years in this analysis.

The analysis examined coal generation in the three large regional interconnections of the U.S. The analysis found that in both 2025 and 2030, for each region, the amount of 2012 coal generation included in the final guidelines' emission performance rate calculation—specifically, the generation remaining after the BSER calculation—is greater than the amount of 2012 generation from coal-fired EGUs that are not fully depreciated in those years under the book life assumptions described above. This shows that the final rule allows flexibility for states to preserve these units as part of their plans.

To put this analysis in perspective: The EPA's role is to set emission guidelines that meet the statutory requirements, which includes consideration of cost in identifying the BSER, as the EPA has done in these guidelines. States have a broad degree of flexibility to design plans to achieve the rates in the emission guidelines in a manner that meets their policy priorities, including ensuring cost-effective compliance. Although not a required component of the EPA's consideration of cost, this analysis shows that the CO_2 emission performance rates in the final guidelines can be met without the retirement of affected EGUs before the end of their book life, and without the retirement of affected EGUs before the end of the book life of capital-intensive pollution control retrofits installed on those EGUs. Thus, according to this analysis, the CO_2 emission performance rates and state CO_2 emission goals need not result in stranded assets. The EPA recognizes that power plant economics are determined by many aspects of markets that are outside of the EPA's control, such as wholesale power prices and capacity prices, and that the compliance path of least cost may involve retiring assets that have not fully depreciated. Nonetheless, this analysis further demonstrates the extent of flexibility available to states in designing their plans to best serve the policy priorities of the state. Details are available in a memorandum to the docket.[858]

Several commenters said that the statute does not authorize the EPA to require other facilities to achieve greater reductions to compensate for a facility that warrants relief based on remaining useful life. One said that consideration of remaining useful life and other relevant factors is a one-way ratchet that provides relief to sources that cannot achieve the BSER, and that the EPA turns that approach on its head by prohibiting a state from providing such relief to a specific facility unless it can identify another facility to ‘‘punish’’ by requiring additional emissions reductions to offset that relief.

The EPA disagrees with these comments, which proceed from an incorrect premise. The EPA is not determining a BSER-based emission level achievable by each individual facility without trading, and then

[858] Memorandum to Clean Power Plan Docket titled ‘‘Stranded Assets Analysis'' dated July 2015.

requiring better-than-BSER from some facilities to make up for worse-than-BSER performance that a state authorizes for other facilities because of a short remaining useful life. Rather, as previously noted, the guidelines set CO_2 emission performance rates and state CO_2 emission goals that represent the average or aggregate emission level achievable by affected EGUs based on regional average estimates of the impact of applying the BSER to collective groupings of affected EGUs.[859] In estimating the amount of improvement achievable through each building block (*e.g.,* improvement in heat rate or amount of generation shift to lower-emitting EGUs), the EPA has estimated the average level achievable by EGUs in a region rather than attempting to estimate the level achievable by each and every affected EGU in the absence of trading. Thus, the fact that an individual facility may be unable, for example, to achieve the average level of heat rate improvement assumed in goal-setting is consistent with the EPA's analysis, and does not undermine the EPA's determination of CO_2 emission performance rates and state CO_2 emission goals. The Legal Memorandum discusses additional reasons that the agency disagrees with comments that the guideline must permit adjustments in the guidelines' CO_2 emission performance rates and state CO_2 emission goals based on remaining useful life considerations.

An additional reason that the EPA believes that consideration of remaining useful life and other facility-specific factors does not warrant adjustments to state goals is that the design of the guidelines does not mandate that states impose requirements that would call for substantial capital investments at affected EGUs late in their useful life. Multiple methods are available for reducing emissions from affected EGUs that do not involve capital investments by the owner/operator of an affected EGU. For example, generation shifts among affected EGUs, and addition of new RE generating capacity do not generally involve capital investments by the owner/operator at an affected EGU. Additional emission reduction methods available to states that do not entail significant capital costs at affected EGUs are discussed elsewhere in this preamble.

Heat rate improvements at affected EGUs may require capital investments. However, states have flexibility to design their plan requirements; they are not required to mandate heat rate improvements at plants that have limited remaining useful life. In fact, a state can choose whether or not to require heat rate improvements at all. The agency also notes that capital expenditures for heat rate improvements would be much smaller than capital expenditures required for example, for purchase and installation of scrubbers to remove SO_2; a fleet-wide average cost for heat rate improvements based primarily on best practices at coal-fired generating units would not likely exceed \$100/kW, compared with a typical SO_2 wet scrubber cost of \$500/kW (costs vary with unit size).[860] Even if a state did choose to adopt requirements for heat rate improvements, the proposed guidelines would allow states to regulate affected EGUs through flexible regulatory approaches that do not require affected EGUs to incur large capital costs (*e.g.,* averaging and trading programs). Under the EPA's final approach—establishing state goals and providing states with flexibility in plan design—states have flexibility to make exactly the kind of judgments necessary to avoid requiring capital investments that would result in stranded assets.

Remaining useful life and other factors, because of their facility-specific nature, are potentially relevant as states determine requirements that are directly applicable to affected EGUs. If relief is due a particular facility, the state has an available toolbox of emission reduction methods that it can use to develop a section 111(d) plan that will achieve the CO_2 emission performance rates or state CO_2 emission goals on time. The EPA therefore concludes that the remaining useful life of affected EGUs, and the other facility-specific factors identified in the existing implementing regulations, should not be regarded as a basis for adjusting the CO_2 emission performance rates or a state CO_2 emission goal, and should not relieve a state of its obligation to develop and submit an approvable plan that achieves that goal on time.

f. *Legal considerations regarding remaining useful life.* Section 111(d)(1) requires the EPA in promulgating section 111(d) regulations to ''permit the State in applying a standard of performance to any particular source under a plan submitted under this paragraph to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies.'' Here, we discuss the legal basis for determining that the emission guidelines are consistent with this statutory requirement. For details, please see the Legal Memorandum.

Section 111(d)(1) only requires that EPA emission guidelines permit states to take into account remaining useful life (among other factors), but section 111(d)(1) does not specify how the EPA must permit that. In other words, the meaning of the provision and the way that the EPA is to implement it in promulgating guidelines are not specified further in the provision. The provision is ambiguous and capable of implementation in several ways, and therefore the EPA has discretion to interpret and apply it. Furthermore, section 111(d)(1) does not suggest that states must be given carte blanche to consider remaining useful life in any way that can be imagined. As detailed above in sections VIII.G.1.c–e, these guidelines permit states to take into account remaining useful life in a number of reasonable ways and thus the guidelines satisfy the statutory obligation.

The phrase ''remaining useful life'' also appears in the visibility provisions of section 169A. There, in determining best available retrofit technology (BART), the state (or the EPA) must take into consideration (among other factors) ''the remaining useful life of the source.'' 42 U.S.C. 7491(g)(2); see also *id.* (g)(1) (reasonable progress). In the context of the visibility program, we have interpreted this provision to mean that the remaining useful life should be considered when calculating the annualized costs of retrofit controls. *See* 40 CFR Pt. 51, App. Y, IV.D.4.k.1. This annualized cost is then used to determine a cost effectiveness, in dollars per ton of pollutant removed on an annual basis. As a result, a technology with a large initial capital cost that might have a reasonable cost-effectiveness for a facility with a long remaining useful life would have a much higher and possibly unreasonable cost-effectiveness for a facility with a short remaining useful life.

Although section 111(d)(1) is different than section 169A(g)(2) and need not be interpreted in the same way, we would note (as discussed in detail in sections VIII.G.1.c–e, section 5.11 of the Response to Comments document, and the Legal Memorandum) that (for

[859] The EPA expects that states that choose to adopt the national CO_2 emission performance rates for all of their EGUs would permit ERC trading, rather than requiring each facility to meet the applicable rate without trading. In effect, the presence of trading means that the EGU performance rates can be achieved by each EGU involved in trading.

[860] Heat rate improvement methods and related capital costs are discussed in the GHG Mitigation Measures TSD; SO_2 scrubber capital costs are from the documentation for the EPA's IPM Base Case v5.13, Chapter 5, Table 5–3, available at *http://www.epa.gov/airmarkets/documents/ipm/Chapter_5.pdf.*

example) a trading program under these section 111(d) guidelines only requires compliance on a periodic basis and does not require any initial capital expenditures. Thus, over the life of the facility, a facility with a short remaining useful life will need fewer total credits or allowances than an otherwise comparable facility with a long remaining useful life, but the annualized cost to the two facilities is the same. In other words, under a trading program remaining useful life of a source is automatically accounted for in the way it is accounted for under the visibility program.

Some commenters stated that the EPA's interpretation of remaining useful life is impermissible. These commenters claimed that states, if they wish to take into account remaining useful life at one affected EGU, must relax the stringency of the emission standard for that EGU. Then, the state would be compelled to increase the stringency of emission standards at other affected EGUs in order to achieve the state performance goal. According to these commenters, section 111(d) does not allow this outcome.

First, the commenters are mistaken in their premise. As discussed in section VIII.G.1, section 5.11 of the Response to Comments document, the Legal Memorandum, and in the example immediately above, states can impose the exact same emission standards on two affected EGUs and still take into account remaining useful life through the availability of trading. In other words, states need not relax an emission standard here and strengthen an emission standard there in order to take into account remaining useful life. Thus, these guidelines permit states to take into account remaining useful life without any of the effects commenters are concerned about.

Second, even if states decide to relax emission standards at one EGU, on the basis of remaining useful life or any other factor, nothing in the last sentence of section 111(d)(1) prohibits these guidelines from requiring the state plan to still meet the CO_2 emission performance rates or state CO_2 emission goal. In fact, that sentence is completely silent on the issue. Thus, the EPA has the discretion to determine what should be the concomitant effects if a state chooses to consider remaining useful life in a particular way. In this case the concomitant effect of a state relaxing one emission standard may be that the state must make up for it elsewhere in order to meet the goal, but nothing in section 111(d)(1), including the statutory requirement to permit consideration of remaining useful life, prohibits that outcome.

2. Electric Reliability

The final rule features overall flexibility, a long planning and implementation horizon, and a wide range of options for states and affected EGUs to achieve the CO_2 emission performance rates or state CO_2 emission goal. This design reflects, among other things, the EPA's commitment to ensuring that compliance with the final rule does not interfere with the industry's ability to maintain the reliability of the nation's electricity supply. Comments from state, regional and federal reliability entities, power companies and others, as well as consultation with the Department of Energy (DOE) and Federal Energy Regulatory Commission (FERC), helped inform a number of changes made in this final rule to address reliability. In addition, FERC conducted one national and three regional technical conferences on the proposed rule in which the EPA participated and at which the issue of reliability was raised by numerous participants.

As discussed throughout the preamble and TSDs, the electricity sector is undergoing a period of intense change. While the change in the resource mix has accelerated in recent years, wind, solar, other RE, and EE resources have been reliably participating in the electric sector for a number of years. Many of the potential changes to the electric system that the final rule may encourage, such as shifts to cleaner sources of power and efforts to reduce electricity demand, are already well underway in the electric industry. To the extent that the final rule accelerates these changes, there are multiple features well embedded in the electricity system that ensure that electric system reliability will be maintained. Electric system reliability is continually being considered and planned for. For example, in the Energy Policy Act of 2005, Congress added a section to the Federal Power Act to make reliability standards mandatory and enforceable by FERC and the North American Electric Reliability Corporation (NERC), the Electric Reliability Organization which FERC designated and oversees. Along with its standards development work, NERC conducts annual reliability assessments via a 10-year forecast and winter and summer forecasts; audits owners, operators, and users for preparedness; and educates and trains industry personnel. Numerous other entities such as FERC, DOE, state PUCs, ISOs/RTOs, and other planning authorities also consider the reliability of the electric system. There are also numerous remedies that are routinely employed when there is a specific local or regional reliability issue. These include transmission system upgrades, installation of new generating capacity, calling on demand response, and other demand-side actions.

Additionally, planning authorities and system operators constantly consider, plan for, and monitor the reliability of the electricity system with both a long-term and short-term perspective. Over the last century, the electric industry's efforts regarding electric system reliability have become multidimensional, comprehensive, and sophisticated. Under this approach, planning authorities plan the system to assure the availability of sufficient generation, transmission, and distribution capacity to meet system needs in a way that minimizes the likelihood of equipment failure.[861] Long-term system planning happens at both the local and regional levels with all segments of the electric system needing to operate together in an efficient and reliable manner. In the short-term, electric system operators operate the system within safe operating margins and work to restore the system quickly if a disruption occurs.[862] Mandatory reliability standards apply to how the bulk electric system is planned and operated. For example, transmission operators and balancing authorities have to develop, maintain, and implement a set of plans to mitigate operating emergencies.[863]

As the electricity market changes and new challenges emerge, electric system regulators and industry participants make changes to how the electric system is designed and operated to respond to these challenges. For example, expressing reliability and rate concerns about fuel assurance issues, FERC recently issued an order requiring ISOs/RTOs to report on the status of their efforts to address market and system performance associated with fuel assurance.[864] In February of 2015, Midcontinent Independent System

[861] Casazza, J. and Delea, F., *Understanding Electric Power Systems: An Overview of the Technology, the Marketplace, and Government Regulations,* IEEE Press, at 160 (2010).

[862] *Id.*

[863] NERC Reliability Standard EOP–001–2.1b—Emergency Operations Planning, available at *http://www.nerc.net/standardsreports/standardssummary.aspx.*

[864] *Centralized Capacity Markets in Regional Transmission Organizations and Independent System Operators,* 149 FERC ¶ 61,145 (2014). FERC generally defines fuel assurance as ''generator access to sufficient fuel supplies and the firmness of generator fuel arrangements''. *Id.* P 5.

Operator (MISO), California Independent System Operator Corporation (CAISO), New York Independent System Operator (NYISO), Southwest Power Pool (SPP), ISO New England (ISO–NE), and PJM Interconnection (PJM) each filed a report with FERC highlighting their efforts to respond to fuel assurance concerns.[865] This is just one of many examples where electric system regulators and industry participants recognize a potential reliability issue and are proactively searching for solutions.

The EPA's approach in this final rule is consistent with our commitment to ensuring that compliance with the final rule does not interfere with the industry's ability to maintain the reliability of the nation's electricity supply. Many aspects of the final rule's design are intended to support system reliability, especially the long compliance period and the basic design that allows states and affected EGUs flexibility to include a large variety of approaches and measures to achieve the environmental goals in a way that is tailored to each state's and utility's energy resources and policies. Despite the flexibility built into the design of the proposal, and the long emission reduction trajectory, many commenters expressed concerns that the proposed rule could jeopardize electric system reliability. We note that the EPA has received similar comments in EPA rulemakings dating as far back as the 1970s. The EPA has always taken and continues to take electric system reliability comments very seriously. These reoccurring comments with regard to reliability notwithstanding, the electric industry has done an excellent job of maintaining reliability, including when it has had to comply with environmental rules with much shorter compliance periods and much less flexibility than this final rule provides. Now, more than ever, the electric industry has tools available to maintain reliability, including mandatory and enforceable reliability standards.[866]

As with numerous prior CAA regulations affecting the electric power sector, environmental requirements for this industry are accommodated within the existing extensive framework established by federal and state law to ensure that electricity production and delivery are balanced on an ongoing basis and planned sufficiently to ensure reliability and affordability into the future. In addition, changes that the EPA is making in this final rule respond directly to the comments and the suggestions that we received on reliability and provide further assurance that implementation of the final rule will not create reliability concerns.

First, the final rule allows significant flexibility in how the applicable CO_2 emission performance rates or the statewide CO_2 goals are met. Given the differing characteristics of the electric grid within each state and region, there are many paths to meeting the final rule's requirements that can be taken while continuing to maintain a reliable electricity supply. As further described elsewhere in section VIII, states can develop plans to meet the CO_2 emission performance rates or state CO_2 emission goals by choosing from a variety of state plan types and approaches that afford states and affected EGUs appropriate flexibility. EE and other measures that were not included in the determination of the BSER can strengthen a state's ability to establish a plan to meet the CO_2 emission performance rates or state CO_2 emission goals by providing a considerable amount of headroom above the levels of the rates and goals. EE especially, because it reduces load, can provide assurance that reliability can and will be maintained. Additionally, the final rule offers opportunities for trading among affected EGUs within and between states, and other multi-state approaches that will further support electric system reliability.

Second, the final rule provides sufficient time to ensure system reliability. The final rule retains the 2030 date for the final period, which commenters largely supported as reasonable and not a concern for reliability, and addresses one of the key issues that commenters pointed to as a reliability-related concern by both moving the start of the interim period from 2020 to 2022 and adjusting the interim goals to provide a more gradual phasing-in of the initial reduction requirement and thus a more gradual emissions reduction trajectory or glide path to the final 2030 goals. These changes deliver on the intent of the proposal to afford states and affected EGUs the latitude to determine their own emissions reduction schedules over the interim period. Both FERC's May 15, 2015 letter[867] and the comment record made it clear that providing sufficient time for planning and implementation is essential to ensuring electric system reliability. The EPA has responded by providing additional time to allow for planning and implementation of the final rule requirements, while at the same time allowing enough time between the beginning of the interim period and 2030 to achieve state goals or emission performance rates. We note that the final rule does not require that all states have met their interim goal or performance rate by 2022 but rather that they meet it on average or cumulatively, as appropriate, during the 2022 to 2029 period.

As a result of these changes, the states themselves will have a meaningful opportunity—which, again, many commenters suggested the timing and stringency of the proposal failed to create despite our intent to do so—to determine the timing, cadence and sequence of actions needed for states and sources to meet final rule requirements while accommodating the ongoing activity needed to ensure system reliability. The final rule provides more than 6 years before reductions are required and an 8-year period from 2022 to 2029 to meet interim goals. Moreover, while the final rule requires each state to submit a plan by September 6, 2016, we recognize that some states may need more than 1 year to complete all of the actions needed for their final state plans, including

[865] For example, ISO–NE and PJM each filed ''pay-for-performance'' proposals to address fuel assurance in their regions. FERC recently acted on ISO–NE market rule changes providing increased market incentives in capacity, energy, and ancillary services markets for generators to be available to meet their obligations during reserve shortages. *ISO New England Inc.,* 147 FERC ¶ 61,172 (2014). Additionally, FERC conditionally approved a PJM ''pay-for-performance'' proposal that creates a new capacity product to provide greater assurance of delivery of energy and reserves during emergency conditions, establishing credits for superior performance and charges for poor performance. *PJM Interconnection, L.L.C.,* 151 FERC ¶ 61,208 (2015).

[866] For example, Andrew Ott, then Executive Vice President-Markets and current President of PJM, an RTO with a substantial amount of coal-fired capacity and generation, discussed the success of PJM's market design in assuring that PJM met and exceeded target reserve margins while MATS was being implemented. *See* Statement of Andrew Ott, PJM Executive Vice President-Markets, FERC Technical Conference on Centralized Capacity Markets in Regional Transmission Organizations and Independent System Operators, AD13–7–000, at 3, 7 (Sept. 25, 2013), *available at http://www.ferc.gov/EventCalendar/EventDetails.aspx?ID=6944&CalType=&CalendarID=116&Date=09/25/2013&View=Listview.* At the FERC national Clean Power Plan Technical Conference, Michael J. Kormos, PJM Executive Vice President-Operations, said that PJM's markets have proven, ''resilient enough to respond to different policy initiatives . . . Whether it is the Sulfur Dioxide Trading Program of the 1990s, the MATS rule or individual state RPS initiatives, the markets have been able to send the appropriate price signals that produce competitive outcomes.'' *See* Michael J. Kormos, PJM Executive Vice President, Statement at FERC Technical Conference on EPA's Clean Power Plan, AD15–4–000, at 3 (Feb. 19, 2015), *available at http://www.ferc.gov/CalendarFiles/20150213081650-Kormos,%20PJM.pdf.*

[867] On May 15, 2015, the five FERC Commissioners sent a letter to Acting Assistant Administrator Janet McCabe regarding the EPA's Clean Power Plan proposal. *See* FERC letter, *available at http://ferc.gov/media/headlines/2015/ferc-letter-epa.pdf.*

consideration of reliability. Therefore, states have the opportunity to receive an extension for submitting a final plan. If the state needs additional time to submit a final plan, then the state may submit an initial submittal by September 6, 2016, that must address three required components sufficiently to demonstrate that a state is able to undertake steps and processes necessary to timely submit a final plan by the extended date of September 6, 2018.

Third, we are including in the final rule a requirement that each state demonstrate in its final state plan submittal that it has considered reliability issues in developing its plan. This was suggested by a number of commenters, and we agree that it is a useful element to state plan development.

Fourth, the final rule provides a mechanism for a state to seek a revision to its plan in order to address changes in circumstances that could have reliability impacts if not accommodated in the plan. The long compliance timeframe, with several interim steps, naturally provides opportunities for states, working with their utilities and reliability entities, to assess how implementation is proceeding, identify unforeseen changes that may warrant plan revisions, and work with the EPA to make necessary revisions. Similarly, the ready availability of emissions trading as a compliance tool affords EGUs ample flexibility to integrate compliance with both routine and critical reliability needs.

Fifth, in response to a variety of comments, we are providing a reliability safety mechanism that provides a path for a state to come to the EPA during an immediate, unforeseen, emergency situation that threatens reliability to notify the EPA that an affected EGU or EGUs may need to temporarily comply with modified emission standards to respond to this kind of reliability concern.

Sixth and finally, we are committed to maintaining an ongoing relationship with FERC and DOE as this final rule is implemented to help ensure continued reliable electric generation and transmission.

We provide more details about these various elements of the final rule, as well as other features of the rule that support system reliability, below.

a. *Summary of key comments.*

The EPA received a number of comments regarding the proposed rule and electric reliability. Many commenters provided specific, useful ideas regarding changes that could be made to the proposal to specifically address their reliability concerns. For example, many commenters state that allowing additional time to comply could help in meeting the final rule requirements while addressing their reliability concerns. Some commenters suggest that additional time would allow them to evaluate potential reliability impacts and system changes that need to be made to comply with final rule requirements while allowing affected EGUs time to meet interim CO_2 emissions goals. The EPA also received comment that market-based approaches have features that could help support reliability, and therefore we should encourage states to join or form regional market-based programs. Commenters also stated that the EPA should require states to consult with grid operators who would analyze the impact of state plans on reliability. A number of commenters also suggested that the EPA should include some sort of reliability safety valve in the final rule. We note that many participants at the FERC technical conferences on the proposed rule also discussed a reliability safety valve in great detail with many suggestions for how such a reliability mechanism could be designed. The EPA appreciates these and all the comments we received regarding the interaction of the proposal and electric reliability. We have carefully considered all comments, consulted further with FERC and incorporated many of the suggested changes in this final rule.

b. *Final rule flexibility.*

In issuing this final rule, the EPA considered public comments on the potential interaction between the proposal and electric reliability. While we have made every effort to develop guidelines that would allow states and utilities to steer clear of potential reliability disruptions, a number of commenters argued that the possibility of an unanticipated reliability event cannot be entirely eliminated. It is important to note that there are many factors that influence system reliability and, given the complexity of the electric grid, electric system planners and operators likely will not completely avoid reliability issues, even in the absence of these guidelines. The EPA designed the final rule to ensure to the greatest extent possible that actions taken by states and affected EGUs to comply with the final rule do not increase potential reliability issues or complicate their resolution. In fact, to the extent that meeting final rule requirements results in the reduction of demand, upgrades in transmission efficiency and infrastructure, and investment in new, more efficient technologies, the outcome could be that the system is more robust and faces fewer risks to electric reliability.

One specific concern raised by many commenters is that the proposed plan development schedule may not leave sufficient time to conduct reliability planning between the development of state plans and the proposed start of the interim period in 2020. To address these concerns and to support a more effective reliability planning process, the EPA is moving the start of the interim period from 2020 to 2022 and adjusting the interim goals to provide a gradually phased-in initial reduction requirement and a more gradual glide path to the final 2030 goals. This more gradual application of the BSER over the 2022–2029 interim period provides the state with substantial latitude in selecting the emission reduction glide path for affected EGUs over that period. As noted above, the final rule also provides states with up to 3 years to adopt and submit their final state plans, and afterwards states can, if necessary, revise their plans, as discussed in section VIII.E.7. This timing gives system planners and operators the opportunity to do what they have already been doing; looking ahead to forecast potential contingencies that pose reliability risks and identifying those actions needed to mitigate those risks. The final rule allows states to develop a pathway over the interim period that reflects their own circumstances, such as reflecting planned additions and changes in generation mix and potentially taking advantage of opportunities for trading of credits or allowances by affected EGUs within and between states. Because achievement of the emission rates or goals can be demonstrated over several years, state plans can accommodate situations where, for example, it may take time to develop new generation, pipelines, or transmission while still providing many options for meeting the final rule requirements and planning for the reliability of the system.

c. *Considering reliability during state plan development process.*

Under CAA section 111(d)(1)(B), state plans must provide for the implementation and enforcement of standards of performance for affected EGUs. The EPA does not believe a state that establishes standards of performance for affected EGUs without taking reliability concerns into consideration satisfactorily provides for the implementation of such standards of performance as required by CAA section 111(d)(1)(B), as a serious reliability issue would disrupt the state's provision of implementation of the state plan. Therefore, the EPA is requiring that each state demonstrate as part of its final state plan submission that it has considered reliability issues while developing its plan in order to ensure that standards of performance can be implemented and enforced as required by the CAA. If system reliability is threatened, the ability of affected EGUs to meet the requirements of this final rule could be compromised if they are required to operate beyond the emission standards established in state plans in order to maintain the reliability of the electric grid. The requirement that states consider reliability as part of the development of state plans is therefore designed to ensure that state plans are flexible enough to avoid this kind of potential conflict between maintaining reliability and providing for the implementation of emission standards for affected EGUs as required by the CAA.

A number of commenters, notably ISOs and RTOs, also discussed reliability concerns in the context of state plans and pointed out that planning and anticipation of change are among the essential ingredients of ensuring the ongoing reliability of the electricity system. To that end, they recommended that as states are developing state plans, their activity include the consideration of the reliability needs of the region in which affected EGUs operate and of the potential impact of actions to be taken in compliance with state plans. Therefore, we are requiring that each state demonstrate in its final state plan submittal that it has considered reliability issues in developing its plan. One particularly effective way in which states can make this demonstration is by consulting with the relevant ISOs/RTOs or other planning authorities as they develop their plans and documenting this consultation process in their state plan submissions. If a state chooses to consider reliability through consultation with the ISO/RTO or other planning authority, the EPA recommends that the state request that the planning authority review the state plan at least once during the plan development stage and provide its assessment of any reliability implications of the plan. Additionally, we encourage states that are considering reliability through an ISO/RTO or other planning authority consultation process to have a continuing dialogue with those entities during development of their final state plan. While following the recommendations of the planning authority would not be mandatory, the state should document its consultation process, any response and recommendations from the planning authority, and the state's response to those recommendations in its final state plan submittal to the EPA. This consultation is designed to inform how the state might adjust its plan for meeting the CO_2 reduction requirements under this guideline; the consultation is not a basis for relaxing that requirement. While we consider this process to be an effective way for a state to demonstrate that it considered reliability in developing its final state plan, a state may provide other comparable support for a demonstration that it has considered reliability during the state plan development process.[868] Also as discussed elsewhere in this preamble, the EPA encourages states to include state utility regulators and the state energy offices in the development of the state plan. These agencies have expertise that can help to assure that state plans complement the state's power sector. The EPA believes that this requirement to demonstrate consideration of reliability will provide an effective reliability evaluation in the state plan development process. It should further help states avoid any conflicts between state plans and the maintenance of reliability during implementation of the state plan and associated emission standards. Finally, we also encourage states as they develop their plans to consider, to the extent possible, other potential issues that may impact affected EGUs. For example, an affected EGU may be in an ISO/RTO that puts certain deadlines on generators that may not line up perfectly with state plan deadlines.

d. *State plan modifications.*

If, during the implementation of a state plan, a reliability issue cannot be addressed within the range of actions or mechanisms encompassed in an approved state plan, the state can submit a plan revision to the EPA to amend its plan. In such a circumstance, the state plan may need to be adjusted to enable affected EGUs to continue to meet final rule requirements without causing an otherwise unmanageable reliability threat. In all cases the plan revision must still ensure the affected EGUs meet the emission performance level set out in the 111(d) final rule. Whether or not these circumstances occur will depend in part upon how each state designs its state plan. States that design plans with a high level of flexibility, such as market-based plans or multi-state plans, are less likely to face a potential conflict between state plan requirements and the maintenance of reliability. States that participate in multi-state programs will be better able to weather unexpected reliability risks.

Events not anticipated at the time of the final plan submittal—such as the retirement of a large low- or zero-emitting unit—may trigger the request for state plan revisions. It may also be the case that affected EGU-specific emission standards in a state plan are proving to be too inflexible to allow the plan to accommodate market or other changes in the power sector. In such instances, there should be a lead time between the announced retirement of the unit and the need to amend the state plan. Therefore, the state should be able to utilize the revisions process that the EPA provides.

The EPA will review a plan revision per the implementing regulation requirements of 40 CFR part 60.28. If the state's request for a state plan revision must be addressed in an expedited manner to assure a reliable supply of electricity, the state must document the risks to reliability that would be addressed by the plan revision by providing the EPA with a separate analysis of the reliability risk from the ISO/RTO or other planning authority. This analysis should be accompanied by a statement from the ISO/RTO or other planning/reliability authority that there are no practicable alternative resolutions to the reliability risk. In this case, the EPA will conduct an expedited review of the state plan revision.[869]

e. *Reliability safety valve.*

In this section we describe a reliability safety valve, available to states with affected EGUs providing reliability-critical generation in emergency circumstances. Specifically and as discussed below the reliability safety valve provides i) a 90-day period during which the affected EGU will not be required to meet the emission standard established for it under the state plan but rather will meet an alternative standard, and ii) a period beginning after the initial 90 days during which the reliability-critical affected EGU may be required to continue to operate under an alternative standard rather than under the original state plan emission standard, as needed in light of the emergency circumstances, and the state must during this period revise its plan to accommodate changes

[868] While the EPA is requiring that the states demonstrate that they have considered reliability in developing their plans, state plan submissions will not be evaluated substantively regarding reliability impacts.

[869] The EPA will still undertake notice and comment rulemaking per the requirements of the Administrative Procedures Act when acting on such state plan revision, but intends to prioritize review of plan revisions needed to address reliability concerns.

needed to respond to ongoing reliability requirements. Any emissions in excess of the applicable state goals or performance rates occurring after the initial 90-day period must be accounted for and offset.

Many commenters expressed concerns that a serious, unforeseen event could occur during the final rule implementation period that would require immediate reliability-critical responses by system operators and affected EGUs that would result in unplanned or unauthorized emissions increases. After reviewing the comments, we believe that it is highly unlikely that there would be a conflict between activities undertaken under an approved state plan and the maintenance of electric reliability, except in the case of a state plan that puts relatively inflexible requirements on specific EGUs. While some have pointed out that severe weather or other short-term events could potentially conflict with state plans, we note that most of those events are of short duration and would not require major—if any—adjustments to emission standards for affected EGUs or to state plans. For example, during an event like the extreme cold experienced in periods of the winter of 2013–2014, affected EGUs may need to run at a higher level for a short period of time to accommodate increased demand and/or short-term unavailability of other generators. However, because compliance by affected EGUs will be demonstrated over 2–3 years, such a short-term event would not cause affected EGUs to be out of compliance with their applicable emission standards. States can also ensure that this is true by developing plans that allow adequate compliance flexibility to accommodate such short-term events. We note that we have included in this final rule a number of different features designed to facilitate emissions trading between and among EGUs on an interstate basis—and have done so, in no small part, in response to comments from states and stakeholders seeking to put in place or operate under state-level and interstate emissions trading regimes. Affected EGUs operating in those circumstances and operating, in addition, subject to state plans that incorporate flexible glide paths and trading would be able to accommodate an unanticipated reliability event.

We recognize, however, that affected EGUs operating in a state with a relatively inflexible state plan could face unanticipated system emergencies that could cause a severe stress on the electricity system for a length of time such that the requirements in that state's plan may not be achievable by certain affected EGUs without posing an otherwise unmanageable risk to reliability. In particular, there could be extremely serious events, outside the control of affected EGUs, that would require an affected EGU or EGUs operating under an inflexible state plan to temporarily operate under modified emission standards to respond to this kind of reliability concern. Examples of such an event could include, a catastrophic event that damages critical or vulnerable equipment necessary for reliable grid operation; a major storm that floods and causes severe damage to a large NGCC plant so that it must shut down; or a nuclear unit that must cease generating unexpectedly and therefore other affected EGUs need to run so as to exceed their requirements under the approved state plan. This is not an all-inclusive list, but the examples illustrate several key attributes of the kinds of circumstances in which the reliability safety valve would apply. First, the event creating the reliability emergency would be unforeseeable, brought about by an extraordinary, unanticipated, potentially catastrophic event. Second, the relief provided would be for EGUs compelled to operate for purposes of providing generation without which the affected electricity grid would face some form of failure. Third, the EGU or EGUs in question would be subject to the requirements of a state plan that imposes emissions constraints such that the EGU or EGUs' operation in response to the reliability emergency resulted in levels of emissions that violated those constraints. We do not anticipate that EGUs operating under a plan that permitted emissions trading would meet these criteria.

The final guidelines provide a reliability safety valve for these types of situations. If an emergency situation arises, the state must submit an initial notification to the appropriate EPA regional office within 48 hours that it is necessary to modify the emission standards for a reliability-critical affected EGU or EGUs for up to an initial 90 days. The notification must include a full description, to the extent it is known at the time, of the emergency situation that is being addressed. It must also identify with particularity the affected EGU or EGUs that are required to run to assure reliability. It must also specify the modified emission standards at which the affected EGU or EGUs will operate. The EPA will consider this notification to be an approved short–term modification to the state plan, allowing the EGU to operate at an emission standard that is an alternative to the emission standard originally specified in the relevant state plan, subject to confirmation by the further documentation described below.[870]

Within 7 days of submitting the initial notification, the state must submit a second notification providing documentation to the appropriate EPA regional office that includes a full description of the reliability concern and why an unforeseen, emergency situation that threatens reliability requires the affected EGU or EGUs to operate under modified emission standards (including discussion of why the flexibilities provided under the state's plan are insufficient to address the concern). The state must also describe in its documentation how it is coordinating or will coordinate with relevant reliability coordinators and planning authorities to alleviate the problem in an expedited manner, and indicate the maximum time that the state anticipates the affected EGU or EGUs will need to operate in a manner inconsistent with its or their obligations under the state's approved plan, and the modified emission standards or levels at which the affected EGU or EGUs will be operating at during this period if it has changed from the initial notification. The documentation must also include a written concurrence from the relevant reliability coordinator and/or planning authority confirming the existence of the imminent reliability threat and supporting the temporary modification request or an explanation of why this kind of concurrence cannot be provided. Additionally, if the relevant planning authority has conducted a system-wide or other analysis of the reliability concern, the state must include that information in its request. If the state fails to submit this documentation on a timely basis, the EPA will notify the state, which must then notify the affected EGU(s) that they must operate or resume operations under the original approved state plan emission standards.

It is important to note that the affected EGUs must continue to monitor and report their emissions and generation pursuant to requirements in this final rule and under the state plan during any short-term modification. For the duration of the up to 90-day short-term modification, the emissions of the affected EGU or EGUs that exceed their obligations under the approved state

[870] The EPA reserves the right to review such notification, and in the event that the EPA finds such notification is improper, the EPA may disallow the short-term modification and affected EGUs must continue to operate under the original approved state plan emission standards.

plan will not be counted against the state's overall goal or emission performance rate for affected EGUs. Such a modification will not alter or abrogate any other obligations under the approved state plan.

During this short-term modification period, the EPA expects that the source, the state and the relevant reliability coordinator and/or planning authority will assess whether the reliability issue can be addressed in a way that would allow the EGU or EGUs to resume operating under the original approved state plan within the 90-day period or whether revisions to the state plan need to be made to address the unexpected circumstances for the longer term (the unexpected unavailability of a nuclear unit, for example).

The EPA recognizes that an emergency may persist past 90 days. At least 7 days before the end of the initial 90-day reliability safety valve period, the state must notify the appropriate EPA regional office whether the reliability concern has been addressed and that the EGU or EGUs can resume meeting the original emission standards established in the state plan prior to the short-term modification.

If there still is a serious, ongoing reliability issue at the end of the short-term modification period that necessitates the EGU or EGUs to emit beyond the amount allowed under the state plan, the state must provide to the EPA a notification that it will be submitting a state plan revision and submit the plan revision as expeditiously as possible, specifying in the notice the date by which the revision will be submitted. The state must document the ongoing emergency with a second written concurrence from the relevant reliability coordinator and/or planning authority confirming the continuing urgent need for the EGU or EGUs to operate beyond the requirements of the state plan and that there is no other reasonable way of addressing the ongoing reliability emergency but for the EGU or EGUs to operate under an alternative emission standard than originally approved under the state plan. In this event, the EPA will work with the state on a case-by-case basis to identify an emission standard for the affected EGU or EGUs for the period before a new state plan revision is approved. After the initial 90-day period, any excess emissions beyond what is authorized in the original approved state plan will count against the state's overall goal or emission performance rate for affected EGUs.

The EPA intends for this reliability safety valve to be used only in exceptional situations. In addition, this reliability safety valve applies only to this final rule and has no effect on CAA requirements to which the state or the affected EGUs are otherwise subject. As discussed earlier, we are providing states with the flexibility to design programs that allow affected EGUs to meet compliance obligations while responding to reliability needs, even in emergency situations. This flexibility means that a conflict between the requirements of the state plan and maintenance of reliability should be extremely rare. We recognize, however, that a state with an inflexible plan could be faced with more than one emergency and in this case the reliability safety valve may be used more than once. If the state finds that a second reliability emergency arises that conflicts with the state plan, the state must submit a revision to its state plan so that the state plan is flexible enough to assure that such conflicts do not recur and that the state is providing for the implementation of the standards of performance for affected EGUs as required by the CAA.

f. *Coordination among federal partners.*

The EPA, DOE, and FERC have agreed to coordinate efforts to help ensure continued reliable electricity generation and transmission during the implementation of the final rule. The three agencies have developed a coordination strategy that reflects their joint understanding of how they will work together to monitor final rule implementation, share information, and resolve any difficulties that may be encountered. This strategy is based on the successful working relationship that the three agencies established in their joint effort to work together to monitor reliability during MATS implementation.

g. *Analyses of the reliability impacts of the proposal.*

The EPA appreciates that a large number of entities from many different industry perspectives have published reports and analysis with respect to electric reliability and the 111(d) proposed rule. We take concerns about reliability very seriously, and we appreciate the attention given to this issue in the comments and shared with us in public forums. It is important to note that these studies were conducted prior to promulgation of this final rule, and thus were only able to consider electric reliability with respect to the proposal. The EPA has made changes and improvements to the proposal in response to comments and new information, and some of the changes are relevant to the final rule's potential effect on electric reliability. One notable change pertains to the start of the interim period, which is now 2022 rather than 2020. Another important change to the final rule is a more gradual phase-in of the BSER for affected EGUs over the interim period (from 2022 through 2029). The final rule also provides considerable flexibility and multiple pathways to states, including allowing their EGUs to use multi-state trading and other approaches, which would allow essential units to continue to meet their compliance obligation while generating even at unplanned but reliability-critical levels. In addition, we have included in the final rule a reliability safety valve provision that can be utilized in certain emergency situations. These changes, in addition to already existing industry mechanisms and planning requirements, will help to ensure that industry will be able to maintain electric reliability. The EPA is confident that the final rule will cut harmful electric power plant pollution while maintaining a reliable electric grid because the final rule provides industry with the time and flexibility needed to continue its current and ongoing planning and investing to modernize and upgrade the electric power system.

In June of 2015, M.J. Bradley & Associates issued a report that enumerated a set of useful guiding principles for studying and evaluating the reliability impacts of the final rule.[871] The report enumerated six principles: (1) A study should be transparent about the assumptions and data used; (2) a study should accurately reflect the existing status of the grid in its modeling assumptions; (3) a study should clearly identify the base case and not confuse what will happen as a result of the final rule with what would have happened anyway; (4) where possible, a study should contain sensitivities and probabilities as they are looking into the future which is necessarily uncertain; (5) a study should reflect the flexibility provided to states to allow them to design compliance approaches to maximize reliability; and (6) a study should provide realistic and reliability-focused results. These principles are helpful to keep in mind when reviewing recent studies.

NERC published its analyses of the proposed rule in November 2014 and again in April 2015.[872] The EPA

[871] M.J. Bradley & Associates, *Guiding Principles for Reliability Assessments Under EPA's Clean Power Plan* (June 3, 2015), *available at http://www.mjbradley.com/node/295.*

[872] North American Electric Reliability Corporation, *Potential Reliability Impacts of EPA's*

Continued

appreciates NERC's attention to, and interest in, the proposed rule. However, we note that like some other studies, NERC assumes considerably less flexibility than actually is provided to states and EGUs in this final rule. The final rule provides states with considerable time and latitude in designing plans that are tailored to the system in which their EGUs operate, which should be reflected in any reliability analysis. Also, the NERC study does not fully reflect the current electric grid. For example, the amount of RE generation that NERC assumes for 2020 is similar to levels of generation that we see today whereas projections for 2020 are considerably higher.[873] Further, NERC conflates retirements that may happen as a result of the rule with those that are already planned. The Brattle Group has also reviewed NERC's November 2014 initial analysis of the proposed rule, noting that it is important to distinguish between concerns about the building blocks and reliability concerns about compliance with state plans.[874] The Brattle Group concluded that there are real world solutions to NERC's concerns. These include making use of the many flexible options available to states under the rule to mitigate reliability risks.

Multiple ISOs/RTOs also provided analyses of the proposed rule, including MISO, PJM, ERCOT, and SPP.[875] For example, MISO conducted an analysis of coal units at risk for retirement, finding that 14 GW of coal may be at risk.[876] SPP performed a resource adequacy analysis that assumes planned retirements plus the EPA's projected retirements, but did not similarly account for the building of new generation capacity.[877] While we appreciate MISO's and SPP's concerns regarding retirements and the potential that reserves will fall below reserve requirement levels, it is important to consider the many ways in which states can develop plans that account for their potential reliability concerns. The final rule continues to give states significant flexibility in how they comply with requirements, including both BSER measures and measures that were not included in the determination of the BSER as a means to comply. For example, demand-side EE measures can greatly assist states and affected EGUs in meeting the standards and/or state plan. Many studies assume that state plans will simply apply the BSER and do not recognize the large number of compliance approaches and opportunities that states and affected EGUs have available to them. The Analysis Group recently analyzed reliability considerations in MISO as the region considers how to comply with the final rule.[878] The Analysis Group found that despite the large amount of coal-fired generating capacity that will likely be retired in MISO in the coming years, the entities responsible for electric system reliability in MISO are prepared to collaboratively address any reliability issues that arise and that there is a ''strong tool kit for managing 'Essential Reliability Services' needed to assure high-quality electric service.'' [879]

ERCOT also performed an analysis, modeling numerous scenarios.[880] ERCOT stated that its modeling identified two potential reliability problems—impacts of units retiring and increased levels of renewable generation on the ERCOT grid.[881] As noted above, the final rule gives additional time for compliance, providing needed time to obtain new or replacement generation necessary as some existing generators retire. Moreover, affected EGUs needed for reliability should be able to employ the flexibilities afforded to them as they seek lower and zero-emitting generation. Finally, we note that ERCOT has a history of notable success in integrating RE into its electric grid, giving ERCOT significant expertise regarding challenges that may arise with the addition of new RE in order to comply with the final rule. In fact, a recent Brattle Group report used ERCOT as a case study for how to effectively integrate a large number of RE into the electric grid.[882]

PJM conducted its own analysis at the request of the Organization of PJM States (OPSI).[883] This analysis is consistent with many of the M.J. Bradley guiding principles. PJM designed various scenarios to capture the impact of the proposed rule under a series of assumptions. Because the EPA had not yet issued the final rule, PJM cautioned against using the report as a reliability analysis or predictor of the future. PJM stated that, since 2007, PJM's capacity markets have helped to attract 35,000 MWs of additional generation. Even though 26,000 MWs will retire between 2009 and 2016, the PJM capacity market has procured sufficient resources to maintain reliability.

WECC also produced a study which is part of a longer-term, phased effort.[884] The assumptions, methodology, and limitations were all clearly presented, and there was extensive involvement by a range of stakeholders. WECC stated that it is embarking on a phased-study process that seeks to ''provide the industry with unbiased and

Proposed Clean Power Plan (Nov. 5, 2014), *available at http://www.nerc.com/news/Pages/Reliability-Review-of-Proposed-Clean-Power-Plan-Identifies-Areas-for-Further-Study,-Makes-Recommendations-for-Stakeholders.aspx*; North American Electric Reliability Corporation, *Potential Reliability Impact of EPA's Proposed Clean Power Plan: Phase 1* (Apr. 21, 2015), *available at http://www.nerc.com/news/Pages/Assessment-Uses-Scenario-Analysis-to-Identify-Potential-Reliability-Risks-from-Proposed-Clean-Power-Plan.aspx*.

[873] EIA, Annual Energy Outlook 2015, with Projections to 2040, April 2015, *available at http://www.eia.gov/forecasts/aeo/pdf/0382(2015).pdf*.

[874] Brattle Group, *EPA's Clean Power Plan and Reliability, Assessing NERC's Initial Reliability Review* (Feb. 2015), *available at http://info.aee.net/hs-fs/hub/211732/file-2486162659-pdf/PDF/EPAs-Clean-Power-Plan-Reliability-Brattle.pdf?t=1434398407867*.

[875] *See* MISO, *Analysis of EPA's Proposal to Reduce CO_2* Emissions from Existing Units (Nov. 12, 2014), *available at https://www.misoenergy.org/Library/Repository/Communication%20Material/EPA%20Regulations/AnalysisofEPAProposalReduceCO2Emissions.pdf*; PJM, *PJM Interconnection Economic Analysis of the EPA Clean Power Plan Proposal* (Mar. 2, 2015), *report listed at http://www.pjm.com/documents/reports.aspx*; SPP, *SPP's Reliability Impact Assessment of the EPA's Proposed Clean Power Plan,* (Oct. 8, 2014), *available at http://www.spp.org/publications/CPP%20Reliability%20Analysis%20Results%20Final%20Version.pdf*; ERCOT, *ERCOT Analysis of the Clean Power Plan* (Nov. 17, 2014), *available athttp://www.ercot.com/content/news/presentations/2014/ERCOTAnalysis-ImpactsCleanPowerPlan.pdf*; and

[876] MISO, *Analysis of EPA's Proposal to Reduce CO_2 Emissions from Existing Units,* at 14 (Nov. 12, 2014), *available at https://www.misoenergy.org/Library/Repository/Communication%20Material/EPA%20Regulations/AnalysisofEPAProposalReduceCO2Emissions.pdf*.

[877] SPP, *SPP's Reliability Impact Assessment of the EPA's Proposed Clean Power Plan,* (Oct. 8, 2014), *available at http://www.spp.org/publications/CPP%20Reliability%20Analysis%20Results%20Final%20Version.pdf*.

[878] Analysis Group, *Electric System Reliability and EPA's Clean Power Plan: The Case of MISO* (June 8, 2015), *available at http://www.analysisgroup.com/uploadedfiles/content/insights/publishing/analysis_group_clean_power_plan_miso_reliability.pdf*.

[879] Analysis Group, *Electric System Reliability and EPA's Clean Power Plan: The Case of MISO,* at 2 (June 8, 2015), *available at http://www.analysisgroup.com/uploadedfiles/content/insights/publishing/analysis_group_clean_power_plan_miso_reliability.pdf*.

[880] ERCOT, *ERCOT Analysis of the Clean Power Plan* (Nov. 17, 2014), *available at http://www.ercot.com/content/news/presentations/2014/ERCOTAnalysis-ImpactsCleanPowerPlan.pdf*.

[881] ERCOT, *ERCOT Analysis of the Clean Power Plan,* at 9 (Nov. 17, 2014), *available at http://www.ercot.com/content/news/presentations/2014/ERCOTAnalysis-ImpactsCleanPowerPlan.pdf*.

[882] Brattle Group, *Integrating Renewable Energy Into the Electricity Grid: Case Studies Showing How System Operators are Maintaining Reliability* (June 2015), *available at http://info.aee.net/integrating-renewable-energy-into-the-electricity-grid*.

[883] PJM, *PJM Interconnection Economic Analysis of the EPA Clean Power Plan Proposal* (Mar. 2, 2015), *report listed at http://www.pjm.com/documents/reports.aspx*.

[884] WECC, *EPA Clean Power Plan: Phase I—Preliminary Technical Report* (Sept. 19, 2014), *available at https://www.wecc.biz/_layouts/15/WopiFrame.aspx?sourcedoc=/Reliability/140912_EPA-111(d)_PhaseI_Tech-Final.pdf&action=default&DefaultItemOpen=1*.

independent analysis of this issue.'' [885] WECC concluded that the effects of the proposal on resource adequacy may be minimal but that resource adequacy cannot be fully assessed without realistic and/or proposed compliance scenarios.[886]

Analysis Group analyzed the proposed rule, finding that it provides states and affected EGUs with a wide range of options and operational discretion that can prevent reliability issues while also reducing carbon pollution and costs.[887] Analysis Group noted that some of the concerns raised by stakeholders about the proposed rule assume ''inflexible implementation, are based upon worst-case scenarios, and assume that policy makers, regulators, and market participants will stand on the sidelines until it is far too late to act'' to ensure reliability.[888] It stated that these assumptions are not consistent with past actions.

We appreciate the time that multiple entities took to analyze and consider the potential impacts of the proposed rule. As we issue the final rule and states draft plans to implement the rule, we look forward to further analysis by these and other groups. Such analysis can provide states with needed resources to help them design state plans that will augment the efforts of the industry to maintain electric reliability.

3. Consideration of Effects on Employment and Economic Development

States in designing their state plans should consider the effects of their plans on employment and overall economic development to assure that the opportunities for economic growth and jobs that the plans offer are manifest. To the extent possible, states should try to assure that any communities that can be expected to experience job losses can also take advantage of the opportunities for job growth or otherwise transition to healthy, sustainable economic growth. The EPA's illustrative analysis indicates that there may be some additional job losses in sectors related to coal extraction and generation that are attributable to implementation of this rule. At the same time, the EPA's illustrative analysis indicates that there may be new jobs in the utility power sector associated with both improving the efficiency of fossil fuel-fired power plants, construction and operation of new natural gas-fired and RE production, and actions to increase demand-side EE. Consideration of these effects in the context of the particulars of the state plan can help states craft plans that, to the extent possible, meet multiple environmental, economic, and workforce development goals.

The Partnerships for Opportunity and Workforce and Economic Revitalization (POWER) Initiative is a new interagency effort led by the Economic Development Administration in the Department of Commerce. POWER was launched to respond to current trends in the power sector: ''The United States is undergoing a rapid energy transformation, particularly in the power sector. This transformation is producing cleaner air and healthier communities, and spurring new jobs and industries. At the same time, it is impacting workers and communities who have relied on the coal industry as a source of good jobs and economic prosperity, particularly in Appalachia, where competition with other coal basins provides additional pressure.'' [889] The POWER Initiative aligns, leverages, and targets economic and workforce development assistance to communities and workers affected by changes in the coal industry and the utility power sector. The POWER Initiative is competitively awarding planning assistance and implementation grants with funding from the Department of Commerce, Department of Labor, Small Business Administration, and the Appalachian Regional Commission to partnerships anchored in impacted communities. These grants will help communities organize themselves, develop comprehensive strategic plans that chart their economic future, and execute coordinated economic and workforce development activities based on their strategic plans.[890]

In addition to POWER, however, the EPA encourages states to use economic and labor market analysis to identify where they can deploy strategies to: (1) Provide a range of employment and training assistance to workers, and economic development assistance to communities affected by the rapid changes underway in the power sector and closely related industries, to diversify their economies, attract new sources of investment, and create new jobs; and (2) mobilize existing education and training resources, including those of community and technical colleges and registered apprenticeship programs, to ensure that both incumbent and new workers are trained for the skills necessary to meet employer demand for new workers in the utility, construction and related sectors, that such training includes career pathways for members of low-income communities and other vulnerable communities to attain employment in these sectors, and that such training results in validated skill certifications for workers.

4. Workforce Considerations

Some stakeholders commented that, to ensure that emission reductions are realized, it is important that construction, operations and other skilled work undertaken pursuant to state plans is performed to specifications, and is effective, safe, and timely. A good way to ensure a highly proficient workforce is to require that workers have been certified by: (1) An apprenticeship program that is registered with the U.S. DOL, Office of Apprenticeship or a state apprenticeship program approved by the DOL; (2) a skill certification aligned with the U.S. DOE Better Building Workforce Guidelines and validated by a third party accrediting body recognized by DOE; or (3) other skill certification validated by a third party accrediting body.

5. Tenth Amendment Legal Considerations

Some commenters have raised concerns that the emission guidelines and requirements for 111(d) state plans violate principles of federalism embodied in the U.S. Constitution, particularly the Tenth Amendment. These commenters claim that states will be unconstitutionally ''coerced'' or ''commandeered'' into taking certain actions in order to avoid the prospect of either a federal 111(d) plan applying to sources in the state, or of losing federal funds.

We disagree on both fronts. First, the prospect of a federal plan applying to sources in a state does not ''coerce'' or

[885] WECC, *EPA Clean Power Plan: Phase I—Preliminary Technical Report,* at 1 (Sept. 19, 2014), *available at https://www.wecc.biz/_layouts/15/WopiFrame.aspx?sourcedoc=/Reliability/140912_EPA-111(d)_PhaseI_Tech-Final.pdf&action=default&DefaultItemOpen=1.*

[886] WECC, *EPA Clean Power Plan: Phase I—Preliminary Technical Report,* at 30 (Sept. 19, 2014), *available at https://www.wecc.biz/_layouts/15/WopiFrame.aspx?sourcedoc=/Reliability/140912_EPA-111(d)_PhaseI_Tech-Final.pdf&action=default&DefaultItemOpen=1.*

[887] Analysis Group, *Electric System Reliability and EPA's Clean Power Plan Tools and Practices* (Feb. 2015), *available at http://www.analysisgroup.com/uploadedfiles/content/insights/publishing/electric_system_reliability_and_epas_clean_power_plan_tools_and_practices.pdf.*

[888] Analysis Group, *Electric System Reliability and EPA's Clean Power Plan Tools and Practices,* at ES–3 (Feb. 2015), *available at http://www.analysisgroup.com/uploadedfiles/content/insights/publishing/electric_system_reliability_and_epas_clean_power_plan_tools_and_practices.pdf.*

[889] *http://www.eda.gov/power/.*

[890] *https://www.whitehouse.gov/the-press-office/2015/03/27/fact-sheet-partnerships-opportunity-and-workforce-and-economic-revitaliz.*

''commandeer'' that state into submitting its own satisfactory plan. Far from violating principles of federalism, this rule provides states with the initial opportunity to submit a satisfactory state plan, and provides states flexibility in developing that plan. If a state declines to take advantage of that opportunity, affected EGUs in that state will instead be subject to a federal plan that satisfies statutory requirements.[891] This approach is consistent with ordinary cooperative federalism regimes that federal courts have routinely upheld against Tenth Amendment challenges.[892]

Second, states that decline to take certain actions under this rule will not face the prospect of sanctions, such as withdrawn federal highway funds. CAA section 111 does not contain sanctions provisions, and we are finalizing revisions to these emission guidelines making explicit that the EPA will not withhold federal funds from a state on account of that state's failure to submit or implement an approvable 111(d) state plan.

Some commenters pointed to section 110(m) as a possible source of the EPA's sanction authority.[893] Section 110(m) grants the EPA discretionary authority to withhold some federal highway funds under certain conditions. However, section 110(m) requires the EPA to adopt regulations to ''establish criteria for exercising'' this discretionary authority, and the only EPA regulations implementing section 110(m) apply to SIPs submitted under section 110.[894]

The EPA never intended to even imply that we would contemplate using this authority to encourage state participation in this rule under section 111. To the contrary, we believe that imposition of a federal plan rather than sanctions is the appropriate path in the context of this program. Accordingly, regardless of whether the EPA could theoretically apply discretionary sanctions against states in the section 111(d) context, the final rule forbids the agency from exercising any such authority. We have included in this rule a provision that prohibits the agency from imposing sanctions in the event that a state fails to submit or implement a satisfactory plan under this rule. As states consider whether to take advantage of the opportunity to develop state plans, they can be assured that the EPA will not withdraw federal funding should they decline to participate.

6. Title VI

States that are recipients of EPA financial assistance must comply with all federal nondiscrimination statutes that together prohibit discrimination on the bases of race, color, national origin (including limited-English proficiency), disability, sex and age. These laws include: Title VI of the Civil Rights Act of 1964; Section 504 of the Rehabilitation Act of 1973; Section 13 of the Federal Water Pollution Control Act Amendments of 1972; Title IX of the Education Act Amendments of 1972; and the Age Discrimination Act of 1975. Compliance with these nondiscrimination statutes is a recipient's separate and distinct obligation from compliance with environmental regulations. In other words, all recipients are required to ensure that all aspects of their state plans do not violate any of the federal nondiscrimination statutes, including Title VI.

The EPA's Office of Civil Rights (OCR) is responsible for carrying out compliance with these federal nondiscrimination statutes and does so through a variety of means including: Complaint investigation; agency-initiated compliance reviews; pre-grant award assurances and audits; and technical assistance and outreach activities. Anyone who believes that any of the federal nondiscrimination laws enforced by OCR have been violated by a recipient of EPA financial assistance may file an administrative complaint with the EPA's OCR.

H. Resources for States To Consider in Developing Plans

As part of the stakeholder outreach and comment processes, the EPA asked states what the agency could do to facilitate state plan development and implementation. In addition, after the comment period closed, the EPA continued to consult with state organizations including the Association of Air Pollution Control Agencies (AAPCA), Environmental Council of the States (ECOS), National Association of Clean Air Agencies (NACAA), National Association of Regulatory Utility Commissioners (NARUC), National Association of State Energy Officials (NASEO) and the National Governors Association (NGA).

Some states indicated that they wanted the EPA to create resources to assist with state plan development, especially resources related to accounting for RE and demand-side EE in state plans. They requested clear methodologies for estimating emission reductions from RE and demand-side EE policies and programs so that these could be included as part of their compliance strategies. Stakeholders said that these tools and metrics should build upon the EPA's ''Roadmap for Incorporating Energy Efficiency/Renewable Energy Policies and Programs into State and Tribal Implementation Plans,'' as well as the State Energy Efficiency Action Network's ''Energy Efficiency Program Impact Evaluation Guide.'' In addition, stakeholders requested clear guidance on how to measure the impacts of RE and demand-side EE programs using established EM&V protocols.

The EPA also heard that states would like guidance on plan development to be released at the same time as this final rule. This guidance should include allowable programs and policies for compliance, examples of compliance pathways, clear information on multi-state plan development, and identification of tools.

As a result of this feedback, in consultation with U.S. DOE and other federal agencies, the EPA continued to refine its toolbox of decision support resources at: *http://www2.epa.gov/www2.epa.gov/cleanpowerplantoolbox*. The site includes information on regulatory requirements, including state plan guidance and state plan decision support. The state plan guidance section serves as a central repository for the final emission guidelines, RIA, guidance documents, TSDs and other supporting materials. The state plan decision support section includes information to help states evaluate different approaches and measures they might consider as they initiate plan development. This section includes, for example, a summary of existing state climate and RE and demand-side EE policies and programs, information on electric utility actions that reduce CO_2, and tools and information to estimate

[891] Among other things, a federal plan will implement standards of performance subject to specific statutory requirements. *See* 42 U.S.C. 7411(a)(1). The APA and CAA would prohibit the imposition of any federal plan that is ''arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law.'' 5 U.S.C. 706(2)(a). Particularly given these independent constraints on the EPA's authority with respect to any potential federal plan, the prospect of any such plan would not commandeer states or coerce them into submitting their own state plans.

[892] *See, e.g., Hodel* v. *Va. Surface Mining & Reclamation Ass'n, Inc.,* 452 U.S. 264, 283–93 (1981); *Texas* v. *EPA,* 726 F.3d 180, 196–97 (D.C. Cir. 2013) (noting that ''Supreme Court precedent repeatedly affirm[s] the constitutionality of federal statutes that allow States to administer federal programs but provide for direct federal administration if a State chooses not to administer it'').

[893] Other commenters point to CAA section 179 as a possible direct source of this sanctions authority. However, the mandatory sanctions outlined in section 179 clearly apply only in the contexts of nonattainment SIPs and responses to SIP Calls made under CAA section 110(k)(5). *See* 42 U.S.C. 7509(a).

[894] 40 CFR 52.30 (defining ''plan or plan item'').

the emissions impact of RE and demand-side EE programs.

The EPA notes that our inclusion of a measure in the toolbox does not mean that a state plan must include that measure. In fact, inclusion of measures provided at the Web site does not necessarily imply the approvability of an approach or method for use in a state plan. States will need to demonstrate that any measure included in a state plan meets all relevant criteria and adequately addresses elements of the plan components discussed in section VIII.D of this preamble.

I. Considerations for CO_2 Emission Reduction Measures That Occur at Affected EGUs

This section describes a range of emission reduction actions that may be taken at affected EGUs that reduce CO_2 emissions from an affected EGU and/or improve its CO_2 emission rate, and the accounting treatment for these actions in a state plan. Some of these actions do not necessitate additional accounting, monitoring or reporting requirements. Such actions are discussed in section VIII.I.1 below, and include heat rate improvements, fuel switching from one fossil fuel to another, integration of RE into EGU operations, and combined heat and power (CHP) expansion or retrofit. Other actions, however, do necessitate additional accounting, monitoring, or reporting requirements. These include use of CCS, CCU and biomass, as discussed in section VIII.I.2 below.

The discussion in this section applies for both rate-based and mass-based plans. Additional accounting considerations for mass-based plans are discussed in section VIII.J. Additional accounting considerations for rate-based plans, including how actions that substitute for generation from affected EGUs or avoid the need for generation from affected EGUs may be used in a state plan to adjust the CO_2 emission rate of an affected EGU, are discussed in section VIII.K.

1. Actions Without Additional Accounting and Reporting Requirements

Many actions will reduce the reported CO_2 emissions or CO_2 emission rate of an affected EGU, without the need for additional accounting or monitoring and reporting requirements beyond the required CEMS tracking of actual stack CO_2 emissions and tracking of actual energy output.[895] The effect of these actions will result in changes in reported CO_2 emissions and/or energy output by an affected EGU. These actions include:

- heat rate improvements;
- fuel switching to a fossil fuel with lower carbon content (*e.g.,* from coal to natural gas);
- integrated RE;[896] and
- CHP, including retrofit of an affected EGU to a CHP configuration, or revising the useful energy outputs (electrical and thermal) at an affected EGU already operating in a CHP configuration.[897]

Heat rate improvements, fuel switching, integrating RE and CHP would not require any additional accounting or monitoring and reporting, because under the emission guidelines affected EGUs are already required to monitor and report CO_2 emissions at the stack level, and to monitor and report useful energy outputs. Stack monitoring would reflect reductions in CO_2 emissions from efficiency improvements, changes in fuel use (including incorporation of RE), and other on-site changes.

2. Actions With Additional Accounting and Reporting Requirements

Certain actions that may be taken at an affected EGU to reduce CO_2 emissions, specifically application of CCS and CCU, and use of biomass, require additional accounting and reporting.

a. *Application of CCS.* Affected EGUs may utilize retrofit CCS technology to reduce reported stack CO_2 emissions from the EGU.[898] Affected EGUs that apply CCS under a state plan must meet the same monitoring, recordkeeping and reporting requirements for sequestered CO_2 as new units that implement CCS to meet final standards of performance under CAA section 111(b) for new EGUs.[899] Specifically, the final CAA section 111(b) rule for new sources requires that, if a new affected EGU uses CCS to meet the applicable CO_2 emission limit, the EGU must report in accordance with 40 CFR part 98 subpart PP (Suppliers of Carbon Dioxide), and the captured CO_2 must be injected at a facility or facilities that report in accordance with 40 CFR part 98 subpart RR (Geologic Sequestration of Carbon Dioxide).[900,901] See 40 CFR 60.5555(f). Taken together, these requirements ensure that the amount of captured and sequestered CO_2 will be tracked as appropriate at project- and national-levels, and that the status of the CO_2 in its sequestration site will be monitored, including air-side monitoring and reporting. As detailed in the preamble for the CAA section 111(b) standards for new EGUs, the EPA found that there is ample evidence that CCS is technically feasible and that partial CCS can be implemented at a new fossil fuel-fired steam generating EGU at a cost that is reasonable and that is consistent with the cost of other dispatchable, non-NGCC generating options. In the June 2014 proposal, the EPA noted that CCS technology at existing EGUs would entail additional considerations beyond those at issue for newly constructed EGUs. Specifically, the cost of integrating a retrofit CCS system into an existing facility may be expected to be substantial, and some existing EGUs may have space limitations and thus may not be able to accommodate the expansion needed to install the equipment to implement CCS. Further, the EPA noted that aggregated costs of applying CCS as a component of the BSER for the large number of existing fossil fuel-fired steam EGUs would be substantial and would be expected to affect the cost and potentially the supply of electricity on a national basis. Because there are lower-cost systems of emission reduction available to reduce emissions from existing plants, the EPA

[895] Monitoring and reporting requirements for affected EGU CO_2 emissions and useful energy output are addressed in section VIII.F.

[896] ''Integrated RE'' refers to RE that is directly incorporated into the mechanical systems and operation of the EGU. An example is a solar thermal energy system used to preheat boiler feedwater. Such approaches reduce the amount of fossil fuel heat input per unit of useful energy output.

[897] The emission reduction potential from CHP stems from the unit using less fuel for producing useful electrical and thermal outputs than would be required to run separate electrical and thermal units. The emission reduction would depend on the type of affected EGU and available steam hosts in the vicinity of the affected EGU. A conventional combustion turbine generator, for example, converted into a CHP unit could effectively result in a reduction of 25 percent or more in the reported CO_2 emission rate. The potential retrofitte EGU CHP market consists of converted simple cycle turbines, older steam plants in urban areas, and combined cycle units near beneficial thermal loads.

[898] Addition of retrofit CCS technology should not trigger CAA section 111(b) applicability for modified or reconstructed sources. Pollution control projects do not trigger NSPS modifications and addition of CCS technology does not count toward the capital costs of reconstruction for NSPS.

[899] Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units.

[900] The final CAA section 111(b) rule finalizes amendments to subpart PP reporting requirements, specifically requiring that the following pieces of information be reported: (1) The electronic GHG Reporting Tool identification (e-GGRT ID) of the EGU facility from which CO_2 was captured, and (2) the e-GGRT ID(s) for, and mass of CO_2 transferred to, each GS site reporting under subpart RR. As noted, the final 111(b) rule also requires that any affected EGU unit that captures CO_2 to meet the applicable emission limit must transfer the captured CO_2 to a facility that reports under 40 CFR part 98 subpart RR.

[901] Under final requirements in the CAA 111(b) NSPS, any well receiving CO_2 captured from an affected EGU, be it a Class VI or Class II well, must report under subpart RR. A UIC Class II well's regulatory status does not change because it receives such CO_2, nor does it change by virtue of reporting under subpart RR.

did not propose nor finalize CCS as a component of the BSER for existing EGUs.

However, the EPA noted that CCS may be a viable CO_2 mitigation technology at some existing sources and that it would be available to states and to sources as a compliance option. Numerous commenters agreed with the EPA's proposed determination that CCS technology is not part of the BSER building blocks for existing EGUs. Other commenters opposed inclusion of CCS requirements in state plans and provided specific reasons why CCS would not be applicable in certain states. Many commenters felt that CCS technology is not adequately demonstrated and is not economically practical at this time. Other commenters argued that CCS is an available technology and that it can be implemented at more EGUs than predicted by EPA modeling.

Some commenters noted that there are opportunities to reduce the cost of CCS implementation by selling the captured CO_2 for use in Enhanced Oil Recovery (EOR) operations. One commenter expressed concern that federal requirements under the Greenhouse Gas Reporting Program—specifically the requirement (mentioned above) to report under 40 CFR part 98 subpart RR—would foreclose, rather than encourage, the use of captured CO_2 for EOR. The EPA received similar public comments on the CAA 111(b) proposal for new EGUs. The EPA disagrees with the commenters' assertions and addressed those in the preamble for the final standards of performance and in the Response-to-Comments (RTC) document for the CAA 111(b) NSPS rulemaking. The EPA noted that the cost of compliance with subpart RR is not significant enough to offset the potential revenue for the EOR operator from the sale of produced oil for CCS projects that are reliant on EOR. The costs associated with subpart RR are relatively modest, especially in comparison with revenues from an EOR field.

After consideration of the variety of comments we received on this issue, we are confirming our proposal that CCS is not an element of the BSER, but it is an available compliance measure for a state plan. EGUs implementing CCS would need to follow reporting requirements established in the final CAA section 111(b) rule for new affected EGUs.

b. *Application of CCU.*

The EPA received comments suggesting that carbon capture and utilization (CCU) technologies should also be allowed as a CO_2 emission rate adjustment measure for affected EGUs.

Potential alternatives to storing CO_2 in geologic formations are emerging and may offer the opportunity to offset the cost of CO_2 capture. For example, captured anthropogenic CO_2 may be stored in solid carbonate materials such as precipitated calcium carbonate (PCC) or magnesium or calcium carbonate, bauxite residue carbonation, and certain types of cement through mineralization. The carbonate materials produced can be tailored to optimize performance in specific industrial and commercial applications. For example, these carbonate materials have been used in the construction industry and, more recently and innovatively, in cement production processes to replace Portland cement.

The Skyonics Skymine® project, which opened its demonstration project in October 2014, is an example of captured CO_2 being used in the production of carbonate products. This plant converts CO_2 into commercial products. It captures over 75,000 tons of CO_2 annually from a San Antonio, Texas, cement plant and converts the CO_2 into other products including sodium carbonate and sodium bicarbonate.[902] Other companies—including Calera [903] and New Sky [904]—also offer commercially available technology for the beneficial use of captured CO_2. These processes can be utilized in a variety of industrial applications—including at fossil fuel-fired power plants.

However, consideration of how these emerging alternatives could be used to meet CO_2 emission performance rates or state CO_2 emission goals would require a better understanding of the ultimate fate of the captured CO_2 and the degree to which the method permanently isolates the captured CO_2 or displaces other CO_2 emissions from the atmosphere.

Several commenters also suggested that algae-based CCU (*i.e.,* the use of algae to convert captured CO_2 to useful products—especially biofuels) should be recognized for its potential to reduce emissions from existing fossil-fueled EGUs.

Unlike geologic sequestration, there are currently no uniform monitoring and reporting mechanisms to demonstrate that these alternative end uses of captured CO_2 result in overall reductions of CO_2 emissions to the atmosphere. As these alternative technologies are developed, the EPA is committed to working collaboratively with stakeholders to evaluate the efficacy of alternative utilization technologies, to address any regulatory hurdles, and to develop appropriate monitoring and reporting protocols to demonstrate CO_2 reductions.

In the meantime, state plans may allow affected EGUs to use qualifying CCU technologies to reduce CO_2 emissions that are subject to an emission standard, or those that are counted when demonstrating achievement of the CO_2 emission performance rates or a state rate-based or mass-based CO_2 emission. State plans must include analysis supporting how the proposed qualifying CCU technology results in CO_2 emission mitigation from affected EGUs and provide monitoring, reporting, and verification requirements to demonstrate the reductions. The EPA would then review the appropriateness and basis for the analysis and the verification requirements in the course of its review of the state plan.

c. *Application of biomass co-firing and repowering.*

The EPA received multiple comments supporting the use of biomass feedstocks as a means of reducing CO_2 emissions within state plans. Several commenters also asserted that states should be able to determine how biomass can be used in their plans. Additionally, the EPA received a range of comments regarding the valuation of CO_2 emissions from biomass combustion. Some argued that all biomass feedstocks should be considered ''carbon neutral,'' while others maintained that only the full stack emissions from biomass combustion should be counted. As discussed in the next section, the revised *Framework for Assessing Biogenic Carbon Dioxide for Stationary Sources* [905] and 2012 Science Advisory Board peer review of the *2011 Draft Framework* find that it is not scientifically valid to assume that all biogenic feedstocks are ''carbon neutral, but that the net biogenic CO_2 atmospheric contribution of different biomass feedstocks can vary and depends on various factors, including feedstock type and characteristics, production practices, and, in some cases, the alternative fate of the feedstock.[906] Other comments focused on the use of sustainably-derived agricultural and forest biomass feedstocks, including stakeholders who

[902] *http://skyonic.com/technologies/skymine.*

[903] *http://www.calera.com/beneficial-reuse-of-co2/process.html.*

[904] *http://www.newskyenergy.com/index.php/products/carboncycle.*

[905] *www.epa.gov/climatechange/downloads/Framework-for-Assessing-Biogenic-CO2-Emissions.pdf.*

[906] *www.epa.gov/climatechange/ghgemissions/biogenic-emissions.html.*

supported and those against such feedstocks as approvable elements, and those who wanted further definition of these feedstocks. As discussed above and in more detail below, these final guidelines provide that states can include qualified biomass in their plans and include provisions for how qualified biomass feedstocks or feedstock categories will be determined. The EPA will review the appropriateness and basis for determining qualified biomass feedstocks or feedstock categories in its review of the approvability of a state plan.

(1) *Considerations for use of biomass in state plans.*

The EPA recognizes that the use of some biomass-derived fuels can play a role in controlling increases of CO_2 levels in the atmosphere. The use of some kinds of biomass has the potential to offer a wide range of environmental benefits, including carbon benefits. However, these benefits can typically only be realized if biomass feedstocks are sourced responsibly and attributes of the carbon cycle related to the biomass feedstock are taken into account.

In November 2014, the agency released a second draft of the technical report, *Framework for Assessing Biogenic Carbon Dioxide for Stationary Sources.* The revised *Framework,* and the EPA's Science Advisory Board (SAB) peer review of the *2011 Draft Framework,* finds that it is not scientifically valid to assume that all biogenic feedstocks are ''carbon neutral'' and that the net biogenic CO_2 atmospheric contribution of different biogenic feedstocks generally depends on various factors related to feedstock characteristics, production, processing and combustion practices, and, in some cases, what would happen to that feedstock and the related biogenic emissions if not used for energy production.[907] The revised Framework also found that the production and use of some biogenic feedstocks and subsequent biogenic CO_2 emissions from stationary sources will not inevitably result in increased levels of CO_2 to the atmosphere, unlike CO_2 emissions from combustion of fossil fuels.

The SAB peer review panel agreed that the use of biomass feedstocks derived from the decomposition of biogenic waste in landfills, compost facilities or anaerobic digesters did not constitute a net contribution of biogenic CO_2 emissions to the atmosphere. And further, information considered in preparing the second draft of the Framework, including the SAB peer review and stakeholder input, supports the finding that use of waste-derived feedstocks[908] and certain forest-derived industrial byproducts (such as those without alternative markets) are likely to have minimal or no net atmospheric contributions of biogenic CO_2 emissions, or even reduce such impacts, when compared with an alternate fate of disposal.

In addition, as detailed in the President's Climate Action Plan,[909] part of the strategy to address climate change includes efforts to protect and restore our forests, as well as other critical landscapes including grasslands and wetlands, in the face of a changing climate. This country's forests currently play a critical role in addressing carbon pollution, removing more than 13 percent of total U.S. GHG emissions each year.[910] Conservation and sustainable management can help ensure our forests and other lands will continue to remove carbon from the atmosphere while also improving soil and water quality, reducing wildfire risk and enhancing forests' resilience in the face of climate change.

Many states have recognized the importance of forests and other lands for climate resilience and mitigation, and have developed a variety of sustainable forestry policies, RE incentives and standards, and GHG accounting procedures. Some states, for example Oregon and California, have programs that recognize the multiple benefits that forests provide, including biodiversity and ecosystem services protection as well as climate change mitigation through carbon storage. Oregon has several programs focused on best forest management practices and sustainability, including the Oregon Indicators of Sustainable Forests, that promote environmentally, economically and socially sustainable management of state forests. California's Forest Practice Regulations support sustained production of high-quality timber while considering ecological, economic and social values, and the state's Greenhouse Gas Reduction Fund provides resources for forestry projects to improve forest health, maintain carbon storage and avoid GHG emissions from pests, wildfires and conversion to non-forest uses.

Several states focus on sustainable bioenergy, as seen with the sustainability requirements for eligible biomass in the Massachusetts RPS, which, among other requirements, limits old growth forest harvests. Many states employ complementary programs that together work to address sustainable forestry practices. For example, Wisconsin uses a state forest sustainability framework that provides a common system to measure the sustainability of the state's public and private forests, in conjunction with a series of voluntary best management guideline manuals for sustainable woody biomass and agriculturally-derived biomass. In addition to state-specific programs, some states also actively participate in sustainable forest management or certification programs through third-party entities such as the Sustainable Forestry Initiative (SFI) and the Forest Stewardship Council (FSC). For example, in addition to other state sustainability programs, New York has certified more than 780,000 acres of state forestland to both SFI and FSC's sustainable forest management programs. SFI and FSC have certified more than 63 and 35 million acres of forestland across the U.S., respectively.

These examples demonstrate how states already use diverse strategies to promote sustainable forestry and agricultural management while realizing their unique economic, environmental and RE goals. As states evaluate options for meeting the emission guidelines, they may consider how sustainably-derived biomass and sustainable forestry and agriculture programs, such as the examples highlighted above, may help them control increases of CO_2 levels in the atmosphere. In addition, the EPA's work on assessing biogenic CO_2 emissions from stationary sources may also help inform states' efforts to assess the role of different biogenic

[907] Specifically, the SAB found that ''There are circumstances in which biomass is grown, harvested and combusted in a carbon neutral fashion but carbon neutrality is not an appropriate a priori assumption; it is a conclusion that should be reached only after considering a particular feedstock's production and consumption cycle. There is considerable heterogeneity in feedstock types, sources and production methods and thus net biogenic carbon emissions will vary considerably.'' *www.epa.gov/climatechange/ghgemissions/biogenic-emissions.html.*

[908] Types of waste-derived biogenic feedstocks may include: Landfill gas generated through the decomposition of MSW in a landfill; biogas generated from the decomposition of livestock waste, biogenic MSW, and/or other food waste in an anaerobic digester; biogas generated through the treatment of waste water, due to the anaerobic decomposition of biological materials; livestock waste; and the biogenic fraction of MSW at waste-to-energy facilities.

[909] *www.whitehouse.gov/sites/default/files/image/president27sclimateactionplan.pdf.*

[910] *www.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2015-Chapter-6-Land-Use-Land-Use-Change-and-Forestry.pdf.*

feedstocks in their plans and broader climate strategies.[911]

The EPA is engaging in a second round of targeted peer review on the revised Framework with the SAB in 2015.[912] As part of this technical process, and as the EPA and states implement these emission guidelines, the EPA will continue to assess and closely monitor overall bioenergy demand and associated landscape conditions for changes that might have negative impacts on public health or the environment.

(2) *Additional considerations and requirements for biomass fuels.*

The EPA anticipates that some states may consider the use of certain biomass-derived fuels used in electricity generation as a way to control increases of CO_2 levels in the atmosphere, and will include them as part of their state plans to meet the emission guidelines. Not all forms of biomass are expected to be approvable as qualified biomass (*i.e.,* biomass that can be considered as an approach for controlling increases of CO_2 levels in the atmosphere). Affected EGUs may use qualified biomass in order to control or reduce CO_2 emissions that are subject to an emission standard requirement, or those that are counted when demonstrating achievement of the CO_2 emission performance rates or a state rate-based or mass-based CO_2 emission goal.

State plan submissions must describe the types of biomass that are being proposed for use under the state plan and how those proposed feedstocks or feedstock categories should be considered as "qualified biomass" (*i.e.,* a biomass feedstock that is demonstrated as a method to control increases of CO_2 levels in the atmosphere). The submission must also address the proposed valuation of biogenic CO_2 emissions (*i.e.,* the proposed portion of biogenic CO_2 emissions from use of the biomass feedstock that would not be counted when demonstrating compliance with an emission standard, or when demonstrating achievement of the CO_2 emission performance rates or a state rate-based or mass-based CO_2 emission goal).

With regard to assessing qualified biomass proposed in state plans, the EPA generally acknowledges the CO_2 and climate policy benefits of waste-derived biogenic feedstocks and certain forest- and agriculture-derived industrial byproduct feedstocks, based on the conclusions supported by a variety of technical studies, including the revised *Framework for Assessing Biogenic Carbon Dioxide for Stationary Sources.* The use of such waste-derived and certain industrial byproduct biomass feedstocks would likely be approvable as qualified biomass in a state plan when proposed with measures that meet the biomass monitoring, reporting and verification requirements discussed below and other measures as required elsewhere in these emission guidelines.

Given the importance of sustainable land management in achieving the carbon goals of the President's Climate Action Plan, sustainably-derived agricultural and forest biomass feedstocks may also be acceptable as qualified biomass in a state plan, if the state-supplied analysis of proposed qualified feedstocks or feedstock categories can adequately demonstrate that such feedstocks or feedstock categories appropriately control increases of CO_2 levels in the atmosphere and can adequately monitor and verify feedstock sources and related sustainability practices. Information in the revised Framework, the second SAB peer review process, and the state and third party programs highlighted in the previous section can assist states when considering the role of qualified biomass in state plan submittals.

Regardless of what biomass feedstocks are proposed, state plans must specify how biogenic CO_2 emissions will be monitored and reported, and identify specific EM&V, tracking and auditing approaches for qualified biomass feedstocks. As discussed in section VIII.D.2, state plan submittals must include CO_2 emission monitoring, reporting and recordkeeping measures. In the case of sustainably-derived forest- and agriculture-derived feedstocks, this will also include measures for verifying feedstock type, origin and associated sustainability practices. Section VIII.K describes how state plan submittals must specify the requirements and procedures that EM&V measures must meet. As discussed in section VIII.K, the EPA is addressing potential EM&V measures for qualified biomass in EPA's model trading rule and draft EM&V guidance, such as measures that would ensure that biomass-related biogenic CO_2 benefits are quantifiable, verifiable, non-duplicative, permanent and enforceable.

State plan submittals must ensure that all biomass used meets the state plan requirements for qualified biomass and associated biogenic CO_2 benefits, such as using robust, independent third party verification and establishing measures to maintain transparency, including disclosure of relevant documentation and reports. State plan submittals must include measures for tracking and auditing performance to ensure that biomass used meets the state plan requirements for qualified biomass and associated biogenic CO_2 benefits. Details on how to adjust CO_2 rates through the use of qualified biomass feedstocks are provided in section VIII.K.1.

The EPA will review the appropriateness and basis for proposed qualified biomass and biomass treatment determinations and related accounting, monitoring and reporting measures in the course of its review of a state plan. The EPA's determination that a state plan satisfactorily proves that proposed biomass fuels qualify would be based in part on whether the plan submittal demonstrates that proposed state measures for qualified biomass and related biogenic CO_2 benefits are quantifiable, verifiable, enforceable, non-duplicative and permanent. The EPA recognizes that CCS technology (described above in section VIII.I.2.a) could be applied in conjunction with the use of qualified biomass.

(3) *Biomass co-firing.*

Affected EGUs may use qualified biomass co-fired with fossil fuels at an affected EGU. As discussed above in this section, not all forms of biomass are expected to be approvable and states should propose biomass feedstocks and treatment of biogenic CO_2 emissions in state plans, along with supporting analysis where applicable. The EPA will review the appropriateness and basis for such determinations and accounting measures in the course of its review of a state plan.

An affected EGU using qualified biomass as a fuel must monitor and report both its overall CO_2 emissions and its biogenic CO_2 emissions. If biomass is to be used as means to control increases of CO_2 levels in the atmosphere in a state plan, the plan must specify requirements for reporting biogenic CO_2 emissions from affected EGUs.

(4) *Biomass repowering.*

Affected EGUs could fully repower to use primarily qualified biomass. The characteristics of affected EGUs, as discussed in section IV.D, include the use of at least 10 percent fossil fuel for applicability of these emission guidelines. An EGU repowering with at least 90 percent biomass fuels instead of fossil fuels becomes a non-affected

[911] As highlighted in a November 2014 memorandum to the EPA's Regional Air Division Directors. *www.epa.gov/climatechange/ghgemissions/biogenic-emissions.html.*

[912] *www.epa.gov/sab.*

EGU.[913] An EGU repowering with less than 90 percent biomass would remain an affected EGU and therefore need to propose biomass feedstocks and treatment of biogenic CO_2 emissions in state plans, along with supporting analysis where applicable.

J. Additional Considerations and Requirements for Mass-Based State Plans

This section discusses considerations and requirements for different types of mass-based state plans. This includes mass-based state plans using emission budget trading programs, and coordination among such programs where states retain individual mass CO_2 emission goals. CAA section 111(d) requires states to submit, in part, a plan that establishes standards of performance for affected EGUs which reflect the BSER. The state plan must be satisfactory with respect to this requirement in order for the EPA to approve the plan. As previously described, states meet the statutory requirements of 111(d) and the requirements of the final emission guidelines by establishing emission standards for affected EGUs that meet the performance rates, which reflect the application of BSER as determined by the EPA. This final rule allows states to alternatively establish emission standards that meet rate-based or mass-based goals. The state goals must be equivalent to the performance rates in order to reflect the application of the BSER as required by the statute and the final emission guidelines. Therefore, a state choosing a mass-based implementation must address leakage as part of its mass-based plan in order to satisfactorily establish emission standards for affected EGUs that reflect the BSER as set by the EPA.

1. Accounting for CO_2 Emission Reduction Measures in Mass-Based State Plans

As discussed in section VIII.I, measures that occur at affected EGUs will result in CO_2 emission reductions that are automatically accounted for in reported CO_2 emissions. Other measures that provide substitute generation for affected EGUs or avoid the need for generation from affected EGUs, such as demand-side EE, are automatically accounted for under a mass-based plan to the extent that these measures reduce reported CO_2 emissions from affected EGUs. Unlike under a rate-based plan, no additional accounting is necessary in order to recognize these emission reductions.

2. Use of Emission Budget Trading Programs

This section addresses the use of emission budget trading programs in a mass-based state plan, including provisions required for such programs and the design of such programs in the context of a state plan. This includes program design approaches that ensure achievement of a state mass-based CO_2 emission goal (or mass-based CO_2 goal plus new source CO_2 emission complement) (section VIII.J.2.b), as well as how states can use emission budget trading programs with broader source coverage and other flexibility features in a state plan, such as the programs currently implemented by California and the RGGI participating states (section VIII.J.2.c). Section VIII.J.2.d addresses other considerations for the design of emission budget trading programs that states may want to consider, such as allowance allocation approaches. Section VIII.J.3 addresses multi-state coordination among emission budget trading programs used in states that retain their individual state mass-based CO_2 goals.

a. *State plan provisions required for a mass-based emission budget trading program approach.*

For a mass-based emission trading program approach, the state plan would include as its federally enforceable emission standards requirements that specify the emission budget and related compliance requirements and mechanisms. These requirements would include: CO_2 emission monitoring, reporting, and recordkeeping requirements for affected EGUs; provisions for state allocation of allowances; provisions for tracking of allowances, from issuance through submission for compliance; and the process for affected EGUs to demonstrate compliance (allowance ''true-up'' with reported CO_2 emissions). Mass-based emission standards that take the form of an emission budget trading program must be quantifiable, verifiable, enforceable, non-duplicative and permanent. These requirements are described in more detail at section VIII.D.2.

Where a state plan establishes mass-based emission standards for affected EGUs only, the emission standards and the implementing and enforcing measures may be included in the state plan as the full set of requirements implementing the emission budget trading program. Where an emission budget trading program in a state plan addresses affected EGUs and other fossil fuel-fired EGUs or emission sources, pursuant to the approaches described in sections VIII.J.2.b–d below, the requirements that must be included in the state plan are the federally enforceable emission standards in the state plan that apply specifically to affected EGUs, and the requirements that specifically require affected EGUs to participate in and comply with the requirements of the emission budget trading program. This includes the requirement for an affected EGU to surrender emission allowances equal to reported CO_2 emissions, and meet monitoring and reporting requirements for CO_2 emissions, among other requirements. These requirements may be submitted as part of the federally enforceable state plan through mechanisms with the appropriate legal authority and effect, such as state regulations, Title V permit requirements for affected EGUs, and other possible instruments that impose these requirements specifically with respect to affected EGUs. Under this approach, the full set of regulations establishing the emission budget trading program that applies to affected EGUs and other fossil fuel-fired EGUs and other emission sources (if relevant) must be described as supporting documentation in the state plan submittal for EPA to evaluate the approvability of the plan by determining whether the affected EGUs will achieve the requisite goal.

b. *Requirement for emission budget trading programs to address potential leakage.*

In Section VII.D, the EPA specifies that potential emission leakage must be addressed in a state plan with mass-based emission standards. The EPA received comments suggesting various solutions to this concern, such as the inclusion of new sources under the rule and quantitative adjustments to mass CO_2 goals for affected EGUs. In response to this issue, the EPA has sought to give states flexibility in how they meet this requirement and base the acceptable solutions on what will best suit a state's unique characteristics and state plan structure.

To address the potential for emission leakage to new sources under a mass-based plan approach, which could prevent a mass-based program from successfully achieving a mass-based CO_2 goal consistent with BSER, the EPA is requiring that a state submitting a plan that is designed to meet a state mass-based CO_2 goal for affected EGUs demonstrate that the plan addresses and mitigates the risk of potential emission leakage to new sources. The following

[913] For such an EGU to be considered non-affected, the EGU must be subject to a federally enforceable or practically enforceable condition, expressed in (for example) a construction permit or otherwise, that limits the amount of fossil fuel that may be used to 10 percent or less.

options provide sufficient demonstration that potential emission leakage has been addressed in a mass-based state plan: [914]

1. Regulate new non-affected fossil EGUs as a matter of state law in conjunction with emission standards for affected EGUs in a mass-based plan. If a state adopts an EPA-provided mass budget [915] that includes the state mass-based CO_2 goal for affected EGUs plus a new source CO_2 emission complement, this option could be presumptively approvable.

2. Use allocation methods in the state plan that counteract incentives to shift generation from affected EGUs to unaffected fossil-fired sources. If a state adopts allowance set-aside provisions exactly as they are outlined in the finalized model rule, this option could be presumptively approvable.

3. Provide a demonstration in the state plan, supported by analysis, that emission leakage is unlikely to occur due to unique state characteristics or state plan design elements that address and mitigate the potential for emission leakage.

In the first option, states may choose to regulate new non-affected fossil fuel-fired EGUs, as a matter of state law, in conjunction with federally enforceable emission standards for affected EGUs under a mass-based plan. This regulation of both new and existing sources, as part of a state plan approach, is conceptually analogous to a method that has been adopted by the mass-based systems adopted by California and the RGGI participating states. To address potential emission leakage under this option, the mass-based plan includes federally enforceable emission standards for affected EGUs, and the supporting documentation for the plan describes state-enforceable regulations for, at a minimum, all new grid-connected fossil fuel-fired EGUs that meet the applicability standards for EGUs subject to CAA section 111(b). States have the option of regulating a wider array of sources if they choose, as a matter of state law.

For this option, a state must adopt, as a matter of state law, a mass CO_2 emission budget of sufficient size to cover both affected EGUs under the existing source mass CO_2 goal provided in this final rule, along with sufficient CO_2 emission tonnage to cover projected new sources. There are two pathways that states can use for adopting such an emission budget that applies to both affected EGUs and new sources. The EPA is providing a mass budget for each state that account for the state's mass CO_2 goal for affected EGUs and a complementary emission budget for new sources, referred to as the new source CO_2 emission complement. States that both adopt the EPA-provided mass budget, based on the state mass-based CO_2 goal for affected EGUs plus the new source CO_2 emission complement, and regulate new sources under this emission budget as a matter of state law, in conjunction with federally enforceable emission standards for affected EGUs as part of the mass-based state plan may be able to submit a presumptively approvable plan. Such a plan would include federally enforceable emission standards for affected EGUs, and in the supporting documentation of the plan, would describe that the state is regulating new sources under a mass CO_2 emission budget that is equal to or less than the state mass-based CO_2 goal for affected EGUs plus the EPA-specified CO_2 emission complement, in conjunction with the federally enforceable emission standards for affected EGUs. If the state plan is designed to achieve the EPA provided mass budget, plan performance will be evaluated based on whether the existing affected EGUs, regulated under the federally enforceable state plan, and new sources regulated as a matter of state law, together meet the total mass budget that includes the state's mass CO_2 goal for affected EGUs and a complementary emission budget for new sources.

EPA-specified mass CO_2 emission budgets for each state, including the state's mass CO_2 goal and a new source CO_2 emission complement, are provided in Table 14 below. The derivation of the new source CO_2 emission complements is explained in a TSD titled New Source Complements to Mass Goals, which is available in the docket.

TABLE 14—NEW SOURCE COMPLEMENTS TO MASS GOALS

State	New source complements (short tons of CO_2)		Mass goals [916] + new source complements (short tons of CO_2)	
	Interim	Final	Interim	Final
Alabama	856,524	755,700	63,066,812	57,636,174
Arizona	1,424,998	2,209,446	34,486,994	32,380,197
Arkansas	411,315	362,897	34,094,572	30,685,529
California	2,846,529	4,413,516	53,873,603	52,823,635
Colorado	1,239,916	1,922,478	34,627,799	31,822,874
Connecticut	135,410	119,470	7,373,274	7,060,993
Delaware	78,842	69,561	5,141,711	4,781,386
Florida	1,753,276	1,546,891	114,738,005	106,641,595
Georgia	677,284	597,559	51,603,368	46,944,404
Idaho	94,266	146,158	1,644,407	1,639,013
Illinois	818,349	722,018	75,619,224	67,199,174
Indiana	939,343	828,769	86,556,407	76,942,604
Iowa	298,934	263,745	28,553,345	25,281,881
Kansas	260,683	229,997	25,120,015	22,220,822
Kentucky	752,454	663,880	72,065,256	63,790,001
Louisiana	484,308	427,299	39,794,622	35,854,321
Maine	40,832	36,026	2,199,016	2,109,968
Maryland	170,930	150,809	16,380,325	14,498,436
Massachusetts	225,127	198,626	12,972,803	12,303,372
Michigan	623,651	550,239	53,680,801	48,094,302
Minnesota	286,535	252,806	25,720,126	22,931,173

[914] The first two options need not be mutually exclusive; they can both be implemented as part of a mass-based plan.

[915] In Table 14, we have provided a mass budget for each state that includes the state mass-based CO_2 goal and a projection for a new source CO_2 emission complement.

[916] The state mass CO_2 goals can be found in Table 13 in section VII.

TABLE 14—NEW SOURCE COMPLEMENTS TO MASS GOALS—Continued

State	New source complements (short tons of CO_2)		Mass goals[916] + new source complements (short tons of CO_2)	
	Interim	Final	Interim	Final
Mississippi	410,440	362,126	27,748,753	25,666,463
Missouri	668,637	589,929	63,238,070	56,052,813
Montana	421,674	653,801	13,213,003	11,956,908
Nebraska	216,149	190,706	20,877,665	18,463,444
Nevada	770,417	1,194,523	15,114,508	14,718,107
New Hampshire	71,419	63,012	4,314,910	4,060,591
New Jersey	313,526	276,619	17,739,906	16,876,364
New Mexico	527,139	817,323	14,342,699	13,229,925
New York	522,227	460,753	34,117,555	31,718,182
North Carolina	692,091	610,623	57,678,116	51,876,856
North Dakota	245,324	216,446	23,878,144	21,099,677
Ohio	949,997	838,170	83,476,510	74,607,975
Oklahoma	581,051	512,654	45,191,382	41,000,852
Oregon	453,663	703,399	9,096,826	8,822,053
Pennsylvania	1,257,336	1,109,330	100,588,162	90,931,637
Rhode Island	70,035	61,791	3,727,420	3,584,016
South Carolina	344,885	304,287	29,314,508	26,303,255
South Dakota	46,513	41,038	3,995,462	3,580,518
Tennessee	358,838	316,598	32,143,698	28,664,994
Texas	5,328,758	8,516,408	213,419,599	198,105,249
Utah	981,947	1,522,500	27,548,327	25,300,693
Virginia	450,039	397,063	30,030,110	27,830,174
Washington	531,761	824,490	12,211,467	11,563,662
West Virginia	602,940	531,966	58,686,029	51,857,307
Wisconsin	364,841	321,895	31,623,197	28,308,882
Wyoming	1,185,554	1,838,190	36,965,606	33,472,602
Lands of the Navajo Nation	809,562	1,255,217	25,367,354	22,955,804
Lands of the Uintah and Ouray Reservation	84,440	130,923	2,645,885	2,394,354
Lands of the Fort Mojave Tribe	37,162	57,619	648,264	646,138
Total	33,717,871	41,187,289	1,878,255,620	1,709,291,348

States can, in the alternative, provide their own projections for a new source CO_2 emission complement to their mass-based CO_2 goals for affected EGUs. In the supporting documentation for the state plan submittal, the state must specify the new source budget, specify the analysis used to derive such a new source CO_2 emission complement, and demonstrate that under the state plan affected EGUs in the state will meet the state mass-based CO_2 goal for affected EGUs as a result of being regulated under the broader CO_2 emission cap that applied to both affected EGUs and new sources. Such a projection should take into account the mass goal quantification method outlined in section VII.C and the CO_2 Emission Performance Rate and Goal Computation TSD, including the fact that the mass-based state goals already incorporate a significant growth in generation from historical levels. The EPA will evaluate the approvability of the plan based on whether the federally enforceable emission standards for affected EGUs in conjunction with the state-enforceable regulatory requirements for new sources will result in the affected EGUs meeting the state mass-based CO_2 goal. If, rather than designing a plan to achieve the EPA provided mass budget, the state uses its own projections for a new source complement and the plan is approved to meet this new source complement, plan performance will be evaluated based on whether the existing affected EGUs, regulated under the federally enforceable state plan, meet the state's mass CO_2 goal for affected EGUs.

The second demonstration option allows states to use allowance allocation methods that counteract incentives to shift generation from affected EGUs to unaffected fossil-fired sources. These allocation approaches must be specified in state plans as part of the provisions for state allocation of allowances required under a mass-based plan approach (see section VIII.J.2.a). The EPA is proposing the inclusion of two allocation strategies as part of the mass-based approach in the proposed federal plan and model rule: Updating output-based allocations and an allowance set-aside that targets RE. These options are described in more detail below. If a state were to adopt allowance set-aside provisions exactly as they are outlined in the finalized model rule, they could be considered presumptively approvable. The allowance allocation alternative for addressing leakage was chosen for the federal plan and model rule proposal because EPA does not have authority to extend regulation of and federal enforceability to new fossil fuel-fired sources under CAA section 111(d), and therefore we cannot include them under a federal mass-based plan approach.

An updating output-based allocation method allocates a portion of the total CO_2 emission budget to affected EGUs based, in part, on their level of electricity generation in a recent period or periods. Therefore, the total allocation to an EGU that is eligible to receive allowances from an output-based allowance set-aside is not fixed, but instead depends on its generation. Under this approach, each eligible affected EGU may receive a larger allowance allocation if it generates more. Therefore, eligible affected EGUs will have an incentive to generate more in order to receive more allowances, aligning their incentive to generate with new sources.

This allocation method can be implemented through the creation of a set-aside that reserves a subset of the total allowances available to sources, and distributes them based upon the criteria described above. Because the total number of allowances is limited, this allocation approach will not exceed the overall state mass-based CO_2 goal for affected EGUs. Instead, it merely modifies the distribution of allowances in a manner designed to mitigate potential emission leakage.

The other allocation strategy included as part of the mass-based approach in the proposed federal plan and model rule is a set-aside of allowances to be allocated to providers of incremental RE. A set-aside can also be allocated to providers of demand-side EE, or to both RE and demand-side EE. The increased availability of RE generation can serve as another source of generation to satisfy electricity demand. Increased demand-side EE will reduce the demand that sources need to meet. Therefore, both RE and demand-side EE can serve to reduce the incentive that new sources have to generate, and therefore align their incentives with affected EGUs. Thus, increased RE and demand-side EE, supported by a dedicated set-aside, can also serve to address potential emission leakage.

If a state is submitting a plan with an allocations approach that differs from that of the finalized model rule, the state should also provide a demonstration of how the specified allocation method will provide sufficient incentive to counteract potential emission leakage.

Finally, a state can provide a demonstration that emission leakage is unlikely to occur, without implementing either of the two strategies above, as a result of unique factors, such as the presence of existing state policies addressing emission leakage or unique characteristics of the state and its power sector that will mitigate the potential for emission leakage. This demonstration must be supported by credible analysis. The EPA will determine if the state has provided a sufficient demonstration that potential emission leakage has already been adequately addressed, or if additional action is required as part of the state plan.

Aside from the possible incentives for emission leakage addressed in this section, there may be other potential generation incentives across states and unit subcategories that could increase CO_2 emissions, particularly in an environment where various states are implementing a variety of state plan approaches in a shared grid region. Some examples of these incentives, particularly those that were specified by commenters, are discussed in section VIII.L. That section also describes how the EPA has structured this final rule to either prevent or minimize the potential for foregone emission reductions from differential incentives that may result from state plan implementation. These safeguards include placing restrictions on interstate trading when there could be a risk of such differential incentives. Additionally, the nature of the CO_2 emission performance rates and state rate-based CO_2 goals helps to minimize these potential effects, as does the MWh-accounting method for adjusting the CO_2 emission rates of affected EGUs under rate-based plans.

However, without a better understanding of the different mechanisms that states may ultimately choose to meet the emission guidelines, and how different requirements in different states may interact, the EPA cannot project every potential differential incentive that could lead to a loss of CO_2 emission reductions. Therefore, once program implementation begins, the EPA will assess how emission performance across states may be affected by the interaction of different regulatory structures implemented through state plans. Based upon that evaluation, the EPA will determine whether there are potential concerns and what course of action may be appropriate to remedy such concerns.

c. *Emission budget trading programs that ensure achievement of a state CO_2 goal.*

A mass-based emission budget trading program can be designed such that compliance by affected EGUs will achieve the state mass-based CO_2 goal. Under this approach, a state plan would establish CO_2 emission budgets for affected EGUs during the interim and final plan performance periods that are equal to or lower than the applicable state mass-based CO_2 goals specified in section VII. A mass-based emission budget trading program can also be designed such that compliance by affected EGUs in conjunction with new fossil fuel-fired EGUs meeting applicable requirements under state law will achieve a mass-based CO_2 goal plus new source CO_2 emission complement. Under this approach, a state would establish CO_2 emission budgets under state law for affected EGUs plus new sources during the interim and final plan performance periods that are equal to or lower than the applicable state mass-based CO_2 emission goal plus the new source CO_2 emission complement specified in Table 14 in section VIII.J.2.b above, and describe such emission budgets in the supporting documentation of the state plan. Under either program, compliance periods for affected EGUs (or for affected EGUs plus new fossil fuel-fired EGUs meeting applicable requirements under state law) would also be aligned with the interim and final plan performance periods. This approach would limit total CO_2 emissions from affected EGUs (or total CO_2 emissions from affected EGUs and new fossil fuel-fired EGUs meeting applicable requirements under state law) during the interim and final plan performance periods to an amount equal to or less than the state's mass-based CO_2 goal (or mass-based CO_2 goal plus new source CO_2 emission complement).

Under this approach, compliance by affected EGUs with the mass-based emission standards in a plan would ensure that the state achieves its mass-based CO_2 goal for affected EGUs (or mass-based CO_2 goal plus new source CO_2 emission complement). No further demonstration would be necessary by the state to demonstrate that its plan would achieve the state's mass-based CO_2 goal (or mass-based CO_2 goal plus new source CO_2 emission complement).

For this type of plan, where the emission budget is equal to or less than the state mass CO_2 goal (or mass-based CO_2 goal plus new source CO_2 emission complement),[917] the EPA would assess achievement of the state goal based on compliance by affected EGUs with the mass-based emission standards, rather than reported CO_2 emissions by affected EGUs during the interim plan performance periods and final plan performance periods. This approach would allow for allowance banking between performance periods, including the interim and final performance periods outlined in this final rule.

Banking provisions have been used extensively in rate-based environmental programs and mass-based emission budget trading programs. This is because banking reduces the cost of attaining the requirements of the regulation. The EPA has determined that the same rationale and outcomes apply under a CO_2 emission rate approach, in that allowing banking will reduce compliance costs. Banking encourages additional emission reductions in the near-term if economic to meet a long-term emission rate constraint, which is beneficial due to social preferences for environmental improvements sooner rather than later. It is also beneficial when addressing pollutants that are long-lived in the atmosphere, such as CO_2, and where increasing atmospheric concentration of

[917] As specified for the interim plan performance period (including specified levels in interim steps 1 through 3) and the final two-year plan performance periods.

the pollutant leads to increasing adverse atmospheric impacts.

Banking also provides long-term economic signals to affected emission sources and other market participants where actions taken today will have economic value in helping meet tighter emission constraints in the future, provided those emission sources expect that the banked ERCs or emission allowances may be used for compliance in the future. Linking short-term and long-term economic incentives, which allows owners or operators of affected EGUs and other market participants to assess both short-term and long-term incentives when making decisions about compliance approaches or emission reduction investments, reduces long-term compliance costs for affected EGUs and ratepayer impacts. In addition, the increased temporal flexibility provided by banking would further help address potential electric reliability concerns, as banked ERCs can be used to meet emission standard requirements for an affected EGU.

d. *Addressing emission budget trading programs with broader source coverage and other flexibility features.*

As described in section VIII.C above, under the emission standards plan type, a mass-based emission budget trading program with broader source coverage and other flexibility features may be designed such that compliance by affected EGUs (or compliance by affected EGUs plus new fossil fuel-fired EGUs meeting applicable requirements under state law) would assure achievement of the applicable state mass-based CO_2 goal (or mass-based CO_2 goal plus new source CO_2 emission complement).[918]

However, emission budget trading programs, including those currently implemented by California and the RGGI participating states, include a number of different design elements that functionally expand the emission budget under certain circumstances. If a state chose, it could apply such mass-based emission standards, in the form of an emission budget trading program that differs in design from that outlined in section VIII.J.2.c above. These types of emission budget trading programs must be submitted as a part of a state measures plan type. Where an emission budget trading program addresses affected EGUs and other fossil fuel-fired EGUs, the requirements that must be included in the state plan are the federally enforceable emission standards in the state plan that apply specifically to affected EGUs, and the requirements that specifically require affected EGUs to participate in and comply with the requirements of the emission budget trading program. This includes the requirement for an affected EGU to surrender emission allowances equal to reported CO_2 emissions, and meet monitoring and reporting requirements for CO_2 emissions, among other requirements. These requirements may be submitted as part of the federally enforceable state plan through mechanisms with the appropriate legal authority and effect, such as state regulations, relevant Title V permit requirements for affected EGUs, and other possible instruments that impose these requirements specifically with respect to affected EGUs.[919] Under this approach, the full set of regulations establishing the emission budget trading program that applies to affected EGUs and other fossil fuel-fired EGUs and other emission sources (if relevant) must be described as supporting documentation in the state plan submittal. This structure is appropriate to ensure that states with an emission budget trading program that addresses both affected EGUs and other fossil fuel-fired EGUs do not inappropriately submit requirements regarding entities other than affected EGUs for inclusion in the federally enforceable state plan.

Such state programs could include a number of different design elements. This includes broader program scope, where a program includes other emission sources beyond affected EGUs subject to CAA section 111(d) and new fossil fuel-fired EGUs, such as industrial sources. Programs might also include design elements that make allowances available in addition to the established emission budget. This includes project-based offset allowances or credits from GHG emission reduction projects outside the covered sector and cost containment reserve provisions that make additional allowances available at specified allowance prices.[920]

In the case where an emission budget trading program contains elements that functionally expand the emission budget in certain circumstances, compliance by affected EGUs with the mass-based emission standards would not necessarily ensure that CO_2 emissions from affected EGUs do not exceed the state's mass-based CO_2 goal (or mass-based CO_2 goal plus new source CO_2 emission complement). However, states could modify such programs to remove flexibility mechanisms that functionally expand the emission budget, such as out-of-sector offsets and certain cost containment reserve mechanisms, and submit the program under an emission standards plan type.

Where a state chooses to retain such flexibility mechanisms as part of an emission budget trading program, the program may only be implemented as part of a state measures plan type because these state flexibility mechanisms would not assure CO_2 emissions from affected EGUs do not exceed the state's mass-based CO_2 goal (or mass-based CO_2 goal plus new source CO_2 emission complement). A description of the state measures plan type and related requirements is provided in section VIII.C.3.

Under this type of approach, the state would be required to include a demonstration,[921] in its state plan submittal, of how its state measures, in conjunction with any emission standards on affected EGUs, would achieve the state mass-based CO_2 goal (or mass-based CO_2 goal plus new source CO_2 emission complement). This demonstration would include a projection of the total CO_2 emissions from the fleet of affected EGUs that would occur as a result of compliance with the emission standards in the plan. Section VIII.D.2 discusses how such demonstrations could address design elements of emission budget trading programs with broader scope and additional compliance flexibility mechanisms, such as those included in the California and RGGI programs. Once the plan is implemented, if the mass-based CO_2 goal is not achieved during a plan performance period, the backstop federally enforceable emission standards included in the state plan that apply to affected EGUs would be implemented, as described in section VIII.C.3.b.[922]

[918] Section VIII.J.2.a describes how state plan submittals must include as requirements, or describe as part of supporting documentation, relevant aspects of such emission budget trading programs.

[919] This approach for establishing federally enforceable emission standards based on requirements for affected EGUs subject to a broader emission budget trading program that also covers non-affected emission sources is addressed in section VIII.J.2.d. above.

[920] For example, both the California and RGGI programs allow for the use of allowances awarded to GHG offset projects to be used to meet a specified portion of an affected emission source's compliance obligation. The RGGI program contains a cost containment allowance reserve that makes available additional allowances up to a certain amount, at specified allowance price triggers.

[921] A demonstration of how a plan will achieve a state's rate-based or mass-based CO_2 goal (or mass-based CO_2 goal plus new source CO_2 emission complement) is one of the required plan components, as described in section VIII.D.2.

[922] Achievement of the state mass-based CO_2 goal would be determined based solely on stack CO_2 emissions from affected EGUs. Where a state program includes the ability of an affected emission

Continued

e. *Considerations for mass-based emission budget trading programs.*

The EPA notes that while an emission budget trading program included in an emission standards plan must be designed to achieve a state mass-based CO_2 goal (or mass-based CO_2 goal plus new source CO_2 emission complement), states have wide discretion in the design of such programs, provided the emission standards included in the plan are quantifiable, verifiable, enforceable, non-duplicative, and permanent.

(1) *Allowance allocation.* A key example is state discretion in the CO_2 allowance allocation methods included in the program.[923] This includes the methods used to distribute CO_2 allowances and the parties to which allowances are distributed. For example, if a state chose, it could include CO_2 allowance allocation provisions that provide incentives for certain types of complementary activities, such as RE generation, that help achieve the overall CO_2 emission limit for affected EGUs established under the program. In addition, a state could use its allocation provisions to encourage investments in RE and demand-side EE in low-income communities. States could also use CO_2 allowance allocation provisions to provide incentives for early action, such as RE generation or demand-side EE savings that occur prior to the beginning of the interim plan performance period in 2022. For example, a state could include CO_2 allowance allocation provisions where CO_2 allowances are distributed to RE generators based on MWh of RE generation that occurs prior to 2022. Such provisions might be addressed through a finite set-aside of CO_2 allowances that are available for allocation under these provisions. This set-aside could be additional to a set-aside created by the state for the CEIP discussed in section VIII.B.2.

(2) *Facility-level compliance.* If a state chose, it could evaluate compliance (*i.e.,* allowance true-up) under its emission budget trading program at the facility level, rather than at the individual unit level. The EPA has adopted facility-level compliance in the emission budget-trading programs it administers, including the Acid Rain Program (70 FR 25162), Clean Air Interstate Rule (70 FR 25162), and Cross-State Air Pollution Rule (76 FR 48208). Under this approach, states would still track reported unit-level CO_2 emissions—while evaluating compliance at the facility level—allowing them to track increases and decreases of CO_2 emissions at individual EGUs.

3. Multi-state coordination: Mass-based emission trading programs.

An individual state may provide for the use of CO_2 allowances issued by another state(s) for compliance with the mass-based emission standards in its plan. This type of state plan would include requirements that enable affected EGUs to use allowances issued in other states for compliance under the state's emission budget trading program. This type of state plan must also indicate how CO_2 allowances will be tracked from issuance through use for compliance, through either a joint tracking system, interoperable tracking systems, or use of an EPA-administered tracking system.[924]

Two different implementation approaches could be used to create such links. A state could submit a ''ready-for-interstate-trading'' plan using an EPA-approved tracking system, but the plan would not identify links with other states. A state could also submit a plan with specified bilateral or multilateral links that explicitly identify partner states.

Interstate allowance linkages would not affect the approvability of each state's individual plan. However, different considerations apply for the approvability of an individual plan with such links, based on whether the emission budget trading program in the plan applies only to affected EGUs or includes other emission sources, and if the plan is designed to meet a state mass-based CO_2 goal for affected EGUs only or to meet a mass-based CO_2 goal plus a new source CO_2 emission complement).

Under the first ''ready-for-interstate-trading'' implementation approach, a state would indicate in its state plan that its emission budget trading program will be administered using an EPA-approved (or EPA-administered) emission and allowance tracking system.[925] State plans using a specified EPA-approved tracking system would be deemed by the EPA as ready for interstate linkage upon approval of the state plan. No additional EPA approval would be necessary for states to link their emission budget trading programs, and affected EGUs in those states could engage in interstate trading subsequent to EPA plan approval.

A state would indicate in its plan submittal that its emission budget trading system will use a specified EPA-approved tracking system. The state would also indicate in the regulatory provisions for its emission budget trading program that it would recognize as usable for compliance any emission allowance issued by any other state with an EPA-approved state plan that also uses the specified EPA-approved tracking system.

States could also adopt such a collaborative emission trading approach over time (through appropriate state plan revisions if the plan is not already structured as ready-for-interstate-trading), without requiring all of the original participating states to revise their EPA-approved plans.

Under the second implementation approach, a state could specify the other states from which it would recognize issued emission allowances as usable for compliance with its emission budget trading program. The state would indicate in the regulatory provisions for its emission budget trading program that emission allowances issued in other identified partner states may be used by affected EGUs for compliance. Such plans must indicate how allowances will be tracked from issuance through use for compliance, through either a joint tracking system, interoperable tracking systems, or EPA-administered tracking system. The EPA would assess the design and functionality of this tracking system(s) when reviewing individual submitted state plans.

Under this approach, states could also join such a collaborative emission trading approach over time. However, all participating states would need to revise their EPA-approved plans. If the expanded linkage is among previously approved plans with mass-based emission standards, approval of the plan revision would be limited to assessing the functionality of the shared tracking system or interoperable tracking systems

source to use GHG offsets to meet a portion of its allowance compliance obligation, no ''credit'' is applied to reported CO_2 emissions by the affected EGU. The use of offset allowances or credits in such programs merely allows an affected EGU to emit a ton of CO_2 in the amount of submitted offset allowances or credits. In all cases, there is no adjustment applied to reported stack emissions of CO_2 from an affected EGU when determining compliance with its emission limit.

[923] Allowance allocation refers to the methods used to distribute CO_2 allowances to the owners or operators of affected EGUs and/or other market participants.

[924] The emission standards in each individual state plan must include requirements that address the issuance of CO_2 allowances and tracking of CO_2 allowances from issuance through use for compliance. The description here addresses how those requirements will be implemented through the use of a joint tracking system, interoperable tracking systems, or an EPA-administered tracking system.

[925] The EPA would designate tracking systems that it has determined adequately address the integrity elements necessary for the issuance and tracking of emission allowances. Under this approach, a state could include in its plan such a designated tracking system, which has already been reviewed by the EPA.

in order to maintain the integrity of the linked programs.[926]

a. *Considerations for linked emission budget trading programs.*

For individually submitted plans, interstate emission allowance linkages would not affect the approvability of each state's plan. However, approvability of an individual linked plan would differ based on the structure of the emission budget trading program included in the plan. These differences for plan approvability address distinctions among programs that include only affected EGUs and programs that cover a broader set of emission sources, as well as if the plan is designed to meet a state mass-based CO_2 goal for affected EGUs only or to meet a mass-based CO_2 goal plus a new source CO_2 emission complement. Differences in approval criteria are necessary to ensure that each individual state plan demonstrates it will achieve a state's mass-based CO_2 emission goal for affected EGUs (or mass-based CO_2 goal plus new source CO_2 emission complement). The accounting applied to individual plans to assess whether a state achieves its mass-based CO_2 goal (or mass-based CO_2 goal plus new source CO_2 emission complement) will also differ, based on whether an emission budget trading program includes only affected EGUs (or affected EGUs and applicable new fossil fuel-fired EGUs) or a broader set of emission sources. These considerations are addressed below, for both types of emission budget trading programs.

(1) *Links among emission budget trading programs that only include affected EGUs* or affected EGUs and applicable new fossil fuel-fired EGUs. Where the emission budget trading programs in each plan apply only to affected EGUs subject to the final rule (or emission budget trading programs that apply to affected EGUs under the state plan and applicable new fossil fuel-fired EGUs under state law), and include compliance timeframes for affected EGUs that align with the interim and final plan performance periods, both plans would functionally be meeting an aggregated multi-state mass-based goal (or aggregated mass-based CO_2 goal plus new source CO_2 emission complement), but without formally aggregating the goal (or aggregated mass-based CO_2 goal plus new source CO_2 emission complement). CO_2 emissions from affected EGUs in both states could not exceed the total combined CO_2 emission budgets under the emission standards in the two states. A net ''import'' of CO_2 allowances from one state would mean that allowable CO_2 emissions in the other net ''exporting'' state are less than that state's established emission budget. On a multi-state basis, CO_2 emissions from affected EGUs could not exceed the sum of the states' emission budgets.

Under this approach, if the emission budget for the mass-based emission standard in each plan is equal to or lower than the state's mass-based CO_2 goal (or aggregated mass-based CO_2 goal plus new source CO_2 emission complement, if applicable), compliance by affected EGUs with the mass emission standard in a state[927] would ensure that cumulatively the mass CO_2 goals (or mass-based CO_2 goals plus new source CO_2 emission complements) of the linked states are achieved. As a result, achievement of an individual state's mass CO_2 goal (or mass-based CO_2 goal plus new source CO_2 emission complement) would be assessed by the EPA based on compliance by affected EGUs with the mass-based emission standards in the state plan, rather than reported CO_2 emissions by affected EGUs in the state.[928]

The same accounting approach will apply for such plans in all cases, even if the state is linked to another state emission budget trading program that includes a broader set of emission sources (*e.g.,* sources beyond affected EGUs, or beyond affected EGUs plus applicable new fossil fuel-fired EGUs), as described below. In all cases, where a state plan includes an emission budget trading program that applies only to affected EGUs (or beyond affected EGUs plus applicable new fossil fuel-fired EGUs), and includes compliance timeframes that align with plan performance periods, achievement of a state mass CO_2 goal (or mass-based CO_2 goal plus new source CO_2 emission complement) will be assessed by the EPA based on whether affected EGUs comply with the mass-based emission standard, rather than reported CO_2 emissions from affected EGUs.

(2) *Links with emission budget trading programs that include a broader set of emission sources.* State plans may involve emission budget trading programs that include affected EGUs, applicable new fossil fuel-fired EGUs if a plan includes a new source CO_2 emission complement, and other non-affected emission sources.[929]

Generally, such plans must demonstrate that the mass-based CO_2 goal for affected EGUs (or mass-based CO_2 goal plus new source CO_2 emission complement) in a state will be achieved, as a result of implementation of the emission budget trading program.[930] Where a program includes other non-affected emission sources (*i.e.,* non-affected emission sources that are not subject to a new source CO_2 emission complement) and is linked with other programs,[931] the state plan submittal must include a demonstration that the mass-based CO_2 goal (or mass-based CO_2 goal plus new source CO_2 emission complement) will be achieved, considering the emission allowance links with other programs. The EPA, in determining the approvability of each state's plan under this approach, would evaluate the linkages between plans. Specifically, the EPA would evaluate whether the linkages would enable the affected EGUs (or affected EGUs in conjunction with applicable new fossil fuel-fired EGUs) in each participating state to meet the state's applicable mass-based CO_2 goal (or mass-based CO_2 goal plus new source CO_2 emission complement).

During plan implementation, the EPA would assess whether the affected EGUs in a state achieved the state's mass-based CO_2 goal (or mass-based CO_2 goal plus new source CO_2 emission complement) as follows. Reported CO_2

[926] Depending on the specific regulatory provisions in the emission standards in their approved state plans, participating states may also need to revise their implementing regulations (and by extension their state plans) to accept CO_2 emission allowances issued by new partner states as usable for compliance with their mass-based emission standards.

[927] Compliance by an affected EGU with the emission standard is demonstrated based on surrender to the state of a number of CO_2 allowances equal to its reported CO_2 emissions.

[928] This approach is warranted because under such linked programs, CO_2 emissions from affected EGUs in one state that exceed a state's mass CO_2 goal (or mass-based CO_2 goal plus new source CO_2 emission complement) would be accompanied by CO_2 emissions from affected EGUs in another linked state that are below that state's mass CO_2 goal (or mass-based CO_2 goal plus new source CO_2 emission complement).

[929] This may apply under both an emission standards plan and a state measures plan. Section VIII.J.2.a describes how state plan submissions must include as requirements, or describe as part of supporting documentation, relevant aspects of such emission budget trading programs.

[930] Under a program that applies to affected EGUs and other emission sources, compliance by affected EGUs with the emission standard—a requirement to surrender emission allowances equal to reported emissions—will not assure that a state's CO_2 mass goal (or mass-based CO_2 goal plus new source CO_2 emission complement) is achieved. As a result, a further demonstration is required in the plan that compliance by affected EGUs with the program will result in CO_2 emissions from affected EGUs that are at or below a state's CO_2 mass goal (or mass-based CO_2 goal plus new source CO_2 emission complement).

[931] Section VIII.J.2.a describes how state plan submittals must include as requirements, or describe as part of supporting documentation, relevant aspects of such emission budget trading programs.

emissions from affected EGUs under such plans must be at or below a state's mass-based CO_2 emission goal (or mass-based CO_2 goal plus new source CO_2 emission complement) during an identified plan performance period, with the following state accounting adjustments for net ''import'' and net ''export'' of CO_2 allowances:

- *Net ''imports'' of CO_2 allowances:* Reported CO_2 emissions from affected EGUs in a state may exceed the state CO_2 mass goal (or mass-based CO_2 goal plus new source CO_2 emission complement) during an identified plan performance period in the amount of an adjustment for the net ''imported'' CO_2 allowances during the plan performance period. The adjustment represents the CO_2 emissions (in tons) equal to the number of net ''imported'' CO_2 allowances. Under this adjustment, such allowances must be issued by a state with an emission budget trading program that only applies to affected EGUs (or affected EGUs plus applicable new fossil fuel-fired EGUs). Net ''imports'' of allowances are determined through review of tracking system compliance accounts.
- *Net ''exports'' of CO_2 allowances:* Reported CO_2 emissions from affected EGUs in a state during an identified plan performance period must be equal to or less than the CO_2 mass goal (or mass-based CO_2 goal plus new source CO_2 emission complement) minus an adjustment for the ''exported'' CO_2 allowances during the plan performance period. The adjustment represents CO_2 emissions (in tons) equal to the number of net ''exported'' CO_2 allowances. Net ''exports'' of allowances are determined through review of tracking system compliance accounts.

Where CO_2 emissions from affected EGUs exceed these levels (based on reported CO_2 emissions with applied plus or minus adjustments for net CO_2 allowance ''imports'' or ''exports'') over the 8-year interim period or during any final plan reporting period, or by 10 percent or more during the interim step 1 or step 2 periods, a state would be considered to, in the case of the interim and final periods, not have met its CO_2 mass goal during an identified plan performance period, and in the case of the interim step periods, to not be on course to meet the final goal. As a result, under a state measures state plan, implementation of the backstop federally enforceable emission standards for affected EGUs in the state plan would be triggered.

A net transfer of CO_2 allowances during a plan performance period represents the net number of CO_2 allowances (issued by a respective state) that are transferred from the compliance accounts of affected EGUs in that state to the compliance accounts of affected EGUs in another state.[932] This net transfer is determined based on compliance account holdings at the end of the plan performance period.[933] For example, assume two states, State A and State B, with emission budgets of 1,000 tons of CO_2. Each state issues 1,000 CO_2 allowances. At the end of a plan performance period, affected EGUs in State A collectively hold 500 CO_2 allowances in their compliance accounts that were issued by State A. Affected EGUs in State B collectively hold in their compliance accounts 500 CO_2 allowances issued by State A and 1,000 CO_2 allowances issued by State B. In this simplified example, a net transfer of 500 CO_2 allowances has occurred between State A and State B. State A has ''exported'' 500 CO_2 allowances to State B, while State B has ''imported'' 500 CO_2 allowances from state A.

K. Additional Considerations and Requirements for Rate-Based State Plans

This section discusses considerations and requirements for rate-based state plans. This section discusses eligibility, accounting, and quantification and verification requirements (EM&V) for the use of CO_2 emission reduction measures that provide substitute generation for affected EGUs or avoid the need for generation from affected EGUs in rate-based state plans. These measures may be used to adjust the CO_2 emission rate of an affected EGU under a rate-based state plan. This adjustment may occur when an affected EGU is demonstrating compliance with a rate-based emission standard, or when a state is demonstrating achievement of the CO_2 emission performance rates or applicable rate-based state CO_2 emission goal in the emission guidelines. This section also discusses requirements for state plans that include rate-based emission trading programs, including approaches and requirements for coordination among such programs where states retain individual state rate-based CO_2 emission goals.

1. Adjustments to CO_2 Emission Rates in Rate-Based State Plans

Section VIII.K.1.a below describes the basic accounting method for adjusting a CO_2 emission rate, as well as eligibility requirements for measures that may be used for adjusting a CO_2 emission rate. Section VIII.K.1.b addresses measures that may not be used to adjust the CO_2 emission rate of an affected EGU in a state plan, and explains the basis for this exclusion. Section VIII.K.1.c addresses measures that reduce CO_2 emissions outside the electric power sector. Such measures may not be counted under either a rate-based or mass-based state plan.

a. *Measures taken to adjust the CO_2 emission rate of an affected EGU.* This section describes how measures that substitute for generation from affected EGUs or avoid the need for generation from affected EGUs may be used in a state plan to adjust the CO_2 emission rate of an affected EGU. This section discusses the required accounting method for adjusting a CO_2 emission rate, as well as general eligibility requirements that apply to different categories of measures that may be used to adjust a CO_2 emission rate. Where relevant, this section also discusses additional specific accounting methods and other relevant requirements that apply to different categories of measures.

A CO_2 emission rate adjustment may be applied in different rate-based state plan contexts. For example, in a rate-based emission trading program, adjustments may be applied through the use of ERCs.[934] Regardless of the type of plan in which an adjustment is applied, the same basic accounting and general eligibility requirements described in this section will apply.

As discussed in this section, a wide range of actions may be taken to adjust the reported CO_2 emission rate of an affected EGU in order to meet a rate-based emission standard and/or demonstrate achievement of a state CO_2 rate-based emissions goal. All of the measures described in this section will substitute for generation from affected EGUs or avoid the need for generation

[932] A net transfer metric is applied as of the end of the plan performance period. This net accounting as of a specified date is necessary because multiple individual allowance transfers may occur among accounts during a plan performance period, representing normal trading activity. In addition, net transfers are based on compliance account holdings, because these represent the CO_2 allowances directly available at that point in time for use by an affected EGU for complying with its emission limit. Emission budget trading programs typically allow non-affected entities to hold allowances in general accounts. These parties are free to hold and trade CO_2 allowances, providing market liquidity. General account holdings are not assessed as part of a periodic state net transfer accounting, as these allowances may subsequently be transferred to other accounts in multiple states and do not represent allowances currently held by an affected EGU that can be used for complying with its emission limit.

[933] Compliance account holdings, as used here, refer to the number of CO_2 allowances surrendered for compliance during a plan performance period, as well as any remaining CO_2 allowances held in a compliance account as of the end of a plan performance period.

[934] ERCs may be issued for the measures presented in this section, as well as to affected EGUs that emit at a CO_2 emission rate below their assigned emission rate limit. ERC issuance and trading is discussed in detail in section VIII.K.2. That section addresses the accounting method for ERC issuance to affected EGUs that perform below their assigned CO_2 emission rate.

from affected EGUs, thereby reducing CO_2 emissions. This includes incremental NGCC and RE measures included in the EPA's determination of the BSER, as well as other measures that were not included in the determination of the BSER, such as other RE resources, demand-side EE, CHP, WHP, electricity transmission and distribution improvements, nuclear energy, and international RE imports connected to the grid in the contiguous U.S., as discussed elsewhere in this preamble.

The EPA believes that the broad categories of measures listed in this section address the wide range of actions that are available to reduce CO_2 emissions from affected EGUs under a rate-based state plan. However, the actions that a state could include in a rate-based state plan are not necessarily limited to those described in this section. Other specific actions not listed here may be incorporated in a state plan, provided they meet the general eligibility requirements listed in this section, as well as the other relevant requirements in the emission guidelines.[935] Nor are states required to include in their plans all of the actions that are described in this section.

This section discusses the basic accounting method for adjusting the reported CO_2 emission rate of an affected EGU, through the use of measures that substitute for or avoid generation from affected EGUs. That method is based on adding MWh from such measures to the denominator of an affected EGU's reported CO_2 emission rate (lb CO_2/MWh). Those additional MWh are based on quantified and verified electricity generation or electricity savings from eligible measures, and in the case of an affected EGU's compliance with its emission standard, are reflected in ERCs. This section also addresses eligibility requirements for resources that are used to adjust an affected EGU's CO_2 emission rate.

(1) *General accounting approach for adjusting a CO_2 emission rate.*

In this final rule, the reported CO_2 emission rate of an affected EGU may be adjusted based on quantified and verified MWh from qualifying zero-emitting and low-emitting resources, as described in sections VIII.K.1.a.(2)–(10) below. These MWh are added to the denominator of an affected EGU's reported CO_2 emission rate, resulting in a lower adjusted CO_2 emission rate.

The measures described in these sections reduce mass CO_2 emissions from affected EGUs by substituting zero- or low-emitting generation for generation from affected EGUs, or by avoiding the need for generation altogether (in the case of resources that lower electricity demand through improved demand-side EE and DSM). In both of these cases, generation from an affected EGU is replaced, through substitute generation or a reduction in electricity demand. To the extent that qualifying zero-emitting and low-emitting resources result in reduced generation and CO_2 emissions from an individual affected EGU, those emission impacts are reflected in lower reported CO_2 emissions and a reduction in MWh generation from the affected EGU. However, while there will be a reduction in CO_2 emissions at the affected EGU, the fact that both CO_2 emissions and MWh generation are reduced means that such impacts do not alter the reported CO_2 emission rate of the affected EGU. As a result, the MWh of replacement generation must be added to the denominator of the reported CO_2 emission rate in order to represent those impacts in the form of an adjusted CO_2 emission rate. In this manner, adding MWh from these resources to the denominator of an affected EGU's CO_2 emission rate allows mass CO_2 emission reductions from these measures to be fully reflected in an adjusted CO_2 emission rate.

The following provides a simple calculation example of how MWh of replacement generation added to the denominator of an affected EGU's reported CO_2 emission rate results in a lower adjusted CO_2 emission rate. Assume an affected EGU with CO_2 emissions of 200,000 lb and electric generation of 100 MWh during a reporting period. The affected EGU's reported CO_2 emission rate is 2,000 lb/MWh (200,000 lb CO_2/100 MWh = 2,000 lb/MWh). When complying with its rate-based emission limit, the affected EGU submits 10 ERCs, representing 10 MWh of replacement generation.[936] Adding 10 MWh of replacement generation to the reported MWh generation of the affected EGU results in an adjusted CO_2 emission rate of 1,818 lb CO_2/MWh (200,000 lb CO_2/110 MWh = 1,818 lb CO_2/MWh).

In the case of rate-based CO_2 emission standards, an affected EGU demonstrates compliance with the emission standards if the affected EGU's adjusted CO_2 emission rate calculated in the aforementioned manner is less than or equal to the applicable CO_2 emission standard rate.[937] The CO_2 emission performance rates or rate-based CO_2 goal in the emission guidelines are met if the adjusted CO_2 emission rate of affected EGUs in a state is at or below the specified CO_2 emission rate in a state plan that applies for an identified plan performance period.

Numerous commenters requested that the EPA ensure consistency between goal-setting calculations and the methodology used to demonstrate achievement of a CO_2 emission rate under a state plan. This approach for adjusting a CO_2 emission rate corresponds with how RE, one of the components of the BSER that involves adjustment of a CO_2 emission rate, is represented in the CO_2 emission performance rates in the emission guidelines. Specifically, in the calculation of final CO_2 emission performance rates, the MWhs of RE are reflected in two adjustments of the rate: A reduction of CO_2 emissions from affected EGUs in the numerator and a one-to-one replacement of affected EGU generation in the denominator, where it is assumed that replaced generation from an affected EGU is subtracted from the denominator and the same number of zero-emitting MWh are added.[938]

When demonstrating achievement of a CO_2 emission performance rate, the reported CO_2 emissions already reflect the actual emission reductions from the deployment of qualifying zero-emitting and low-emitting resources across the regional grid; a further adjustment of CO_2 emissions would double count CO_2 emissions impacts across the grid. Consistent with the EPA's calculation of the CO_2 emission performance rates and state rate-based CO_2 goals in the emission guidelines, the zero-emitting MWhs (from substitute generation or a reduction in electricity demand) must still be added to the denominator of a reported CO_2 emission rate to calculate an adjusted CO_2 emission rate that appropriately reflects the replaced generation. Thus, the resultant rate, where the numerator reflects CO_2 emission reductions from qualifying measures, and the denominator reflects replaced generation, is consistent with the goal-setting calculation.

Several commenters suggested that the EPA consider the regional nature of the electricity grid and how RE and demand-side EE impacts generation and CO_2 emissions across the grid when accounting for the impacts of RE and

[935] These requirements are discussed in section VIII.D.

[936] Requirements for the issuance of ERCs and a further discussion of how ERCs are used in compliance with rate-based emission limits are addressed in section VIII.K.2.

[937] Any ERCs used to adjust a CO_2 emission rate must meet requirements in the emission guidelines.

[938] For a detailed discussion of this method, see Section VI.C.3. Form of the Performance Rates, in the Equation section.

demand-side EE measures in a rate-based plan approach. This MWh accounting structure corresponds with the regional treatment of RE resources in the BSER that provide substitute generation in the EPA-calculated CO_2 emission performance rates in the emission guidelines. Consistent with assumptions used in calculating the CO_2 emission performance rates in the emission guidelines, affected EGUs and states can take full credit for the MWh resulting from eligible measures they are responsible for deploying, no matter where those measures are implemented. CO_2 emission reductions from the eligible measures may occur across the region; however, an affected EGU or a state may only take credit for avoided CO_2 emissions at that affected EGU or set of EGUs in question, as reflected in the reported stack CO_2 emissions of affected EGUs.

Because of the separate accounting of MWhs and CO_2 emissions, with emission impacts inherent in reported stack CO_2 emissions and zero-emitting MWh impacts requiring explicit adjustments, the accounting method corresponds with the use of MWh-denominated ERCs in the rate-based emission trading framework specified in this rule. The accounting method only requires a quantification of the MWh generated or avoided by an eligible measure, and thus credits or adjustments can be denominated in MWh and do not need to represent an approximation of the CO_2 emission reductions that result from those MWhs. This creates a crediting system or rate adjustment process that is simpler to implement than one that requires an approximation of avoided CO_2 emissions.

The MWh accounting method also creates a crediting system or rate adjustment process that is indifferent to the rate-based CO_2 emission goals of individual states, or the specific CO_2 emission rate standards that states may apply, and the relative stringency of those goals or standards. Use of ERCs in rate-based emission trading programs is addressed in detail in section VIII.K.2. As a result, the MWh accounting method addresses interstate effects, because it inherently accounts for how generation replacement and CO_2 emission reduction impacts may cross state borders. For example, if the accounting method was informed by avoided CO_2 emission rates, it could create perverse incentives for development of zero- or low-emitting resources in states that result in the greatest calculated estimate of CO_2 emission reductions for each replacement MWh. Instead, this accounting method is indifferent to avoided CO_2 emission rates and creates the same number of zero-emitting credits or adjustment for each MWh of energy generation or savings, wherever they occur. For a detailed discussion on how the accounting method addresses interstate effects, see section VIII.L.

(2) *General eligibility requirements for resources used to adjust a CO_2 emission rate.*

The EPA is finalizing certain general eligibility requirements for resources used to adjust a CO_2 emission rate. These requirements align eligibility with certain factors and assumptions used in establishing the BSER, and by extension, application of the BSER to the performance levels established for affected EGUs in the emission guidelines, as well as state rate and mass CO_2 goals. As a result, the requirements ensure that measures that may be used in a state plan are treated consistently (to the extent possible) with the EPA's assessment of the BSER.[939] These general requirements also address potential interactions among rate and mass plans, as discussed more fully in section VIII.L.

As discussed in the sections that follow, the general eligibility criteria address:

- The date from which eligible measures may be installed (*e.g.,* installation of RE generating capacity and installation of EE measures);
- the date from which MWh from eligible measures may be counted, and applied toward adjusting a CO_2 rate; and
- the need to demonstrate that eligible measures replace or avoid generation from affected EGUs.

(a) *Eligibility date for installation of RE/EE and other measures and MWh generation and savings.*

Incremental emission reduction measures, such as RE and demand-side EE, can be recognized as part of state plans, but only for the emission reductions they provide during a plan performance period. Specifically, this means that measures installed in any year after 2012 are considered eligible measures under this final rule, but only the quantified and verified MWh of electricity generation or electricity savings that they produce in 2022 and future years may be applied toward adjusting a CO_2 emission rate. For example, MWh generation in 2022 from a wind turbine installed in 2013 may be applied toward adjusting a CO_2 emission rate. This 2012 date applies to all eligible measures that are used to adjust a CO_2 emission rate under a state plan. For example, eligible measures, such as CHP, nuclear power and DSM, also must be installed after 2012, but only their generation or savings produced in 2022 and after can be used to adjust a CO_2 emission rate.

As discussed in section VIII.C.2.a, a MWh of generation or savings that occurs in 2022 or a subsequent year may be carried forward (or ''banked'') and applied in a future year. For example, a MWh of RE generation that occurs in 2022 may be applied to adjust a CO_2 emission rate in 2023 or future years, without limitation.[940] These MWh may be banked from the interim to final periods.

This eligibility date criterion is consistent with the date of installation for ''incremental'' RE capacity that is included in the BSER building block 3, which is the basis for RE MWh incorporated in the CO_2 emission performance rates for affected EGUs in the emission guidelines. For more information on RE in the BSER, see section V.E.

Many commenters asserted that proposed state goals did not sufficiently account for actions states take that reduce CO_2 emissions prior to the first plan performance period, and therefore requested that MWhs of electricity generation or electricity savings that occur prior to the first plan performance period be eligible to apply toward adjusting the CO_2 emission rates of affected EGUs. The EPA recognizes the importance of early state action as the basis for significant CO_2 emission reductions and as a key part of enabling state plans to achieve the CO_2 emission performance levels or state CO_2 goals. The ability to count eligible measures installed in 2013 and subsequent years for the MWhs they generate during a plan performance period provides significant recognition for early action, corresponding with the BSER framework that is based on cost-effective actions that many sources are already doing, while still conforming to CO_2 performance rates and state goals that are forward-looking. In order to provide additional incentives for early investment in RE and demand-side EE, the EPA is also establishing the CEIP, as discussed in section VIII.B.2. ERCs distributed by states and the EPA through this program may also be used by affected EGUs to demonstrate compliance with an emission standard,

[939] For example, eligibility requirements include installation dates for eligible RE measures that may be used in a state plan. These dates generally align with the dates used for broadly defining incremental RE resources that were considered in establishing the BSER.

[940] Similarly, as discussed in section VIII.C.2.b.(2).(a), allowances may be banked in a mass-based trading program.

and may be banked from the interim to final periods.

Commenters' concerns about treatment of early actions are further addressed by changes from proposal to the BSER assumptions and the methodology used by the EPA to establish the CO_2 emission performance levels and rate-based state CO_2 goals in the emission guidelines. The specifics of these changes are addressed in section V.A.3. Three examples of those changes are provided below.

First, affected EGUs that have maximized their CO_2 emission reduction opportunities available through early action will be better positioned to meet the BSER CO_2 emission performance rates or state goal applied to affected EGUs in their state. For example, a steam generating unit that has already reduced its CO_2 emission rate through a heat rate improvement may have a CO_2 emission rate of 2,000 lb/MWh whereas its rate was 2,100 lb/MWh prior to the improvement. Therefore, it has less distance to cover to meet its CO_2 emission performance rate.

Second, generation from existing RE capacity installed prior to 2013 has been excluded from the EPA's calculation of the CO_2 emission performances rates in the emission guidelines. That RE generating capacity will still provide zero-emitting generation to the grid meeting demand that will not need to be addressed by existing affected EGUs and will better position states and affected EGUs to meet the CO_2 performances rates or state rate- or mass-based CO_2 goals.

Third, commenters expressed concern that demand-side EE targets as part of proposed state goals reflected an assumption of installation of increased EE measures starting in 2017, which seemed to be an implicit requirement to take action prior to the performance period. Because demand-side EE is not used in calculating the CO_2 emission performance rates in the final emission guidelines, this is no longer a concern. Furthermore, eligible demand-side EE actions that occur after 2012 can be applied toward adjusting the CO_2 emission rates of affected EGUs, providing a significant compliance option that is not assumed in emission performance rates or state goals.

(b) *Demonstration that measures substitute for grid generation.*

Eligible measures must be grid-connected. This eligibility criterion aligns incremental NGCC generation in building block 2. It also aligns with RE generation in building block 3 of the BSER, which substitutes for the need for generation from affected EGUs.

All EE measures must result in electricity savings at a building, facility, or other end-use location that is connected to the electricity grid. EE measures only avoid electric generation from grid-connected EGUs if the electrical loads where the efficiency improvements are made are interconnected to the grid.

Commenters sought clarity on this issue, so the EPA is providing this requirement as part of the final rule. Some commenters advocated for the inclusion of measures that were not grid connected as eligible resources, arguing that some of these measures substituted for non-affected EGUs and resulted in reductions in CO_2 emissions. However, eligible measures must be able to substitute for generation from affected EGUs as defined under this rule, and thus must be tied to the electrical grid.

(c) *Geographic eligibility.*

All eligible emission reduction measures, including RE generation and demand-side EE, may occur in any state, with certain limitations, as described below. To the extent these measures are tied to a state plan,[941] these measures may be used to adjust a CO_2 emission rate, regardless of whether the associated generation or electricity savings occur inside or outside the state.[942] This approach is generally consistent with the approach used in building block 3 of the BSER, which reflects regionally available RE. It also recognizes that emission reduction measures have impacts on electricity generation across the electricity system, both within and beyond a state's borders. A more in-depth discussion of the basis for treatment of in-state and out-of-state measures is provided in section VIII.L.

State plans must demonstrate that emission standards and state measures (if applicable) are non-duplicative. Given the geographic eligibility approach described here, this includes a demonstration that a state plan does not allow recognition of a MWh, for use in adjusting the CO_2 emission rate of an affected EGU, if the MWh is being or has been used for such a purpose under another state plan. Discussion of how such a demonstration can be made in the context of a rate-based emission trading program is in section VIII.D.2.b.

The EPA received many comments on the treatment of in-state and out-of-state RE and demand-side EE. Most commenters recommended crediting of both in-state and out-of-state RE and demand-side EE measures, similar to the final rule approach for eligible emission reductions measures. Commenters argued that this approach makes sense based on the nature of the interconnected electricity grid and allows states and utilities to fully account for their RE and demand-side EE efforts, whether that RE or EE, and its related impacts, occurs inside or outside of their state. Some commenters expressed concerns that, at proposal, states with significant RE resources had large amounts of existing RE capacity included in their state CO_2 goals, but that RE was functionally credited to other states for use in meeting their goals because it was associated with measures (such as an RPS) likely to be included in another state's plan. This concern has been addressed through changes in the BSER RE assumptions in the final rule. This includes regionalization of the RE building block, and removal of existing RE capacity constructed prior to 2012 from the building block. The result of these changes is that the RE incorporated in the BSER is more equally shared across states.

(i) *Measures that occur in states with mass-based plans.*

As discussed above, eligible measures for adjusting the CO_2 emission rate of an affected EGU may occur in any state, with certain conditions. This includes a condition that applies to eligible measures that occur in a state with an EPA-approved plan that is meeting a state mass-based CO_2 goal. Eligible measures that could be used to adjust a CO_2 emission rate under a rate-based state plan which are located in a state with a mass-based plan are restricted from being counted under another state's rate-based plan. An exception is made for RE measures that occur in such mass-based states, because of its unique role in BSER. RE measures must meet additional eligibility criteria in order to be used to adjust the CO_2 emission rate of an affected EGU in a state with a rate-based plan. This exception only applies to RE; other emission reduction measures that were not included in the determination of the BSER located in mass-based states, including demand-side EE, are restricted from ERC issuance in rate-based states.

[941] As used here, a measure is ''tied to a state plan'' if it is issued an ERC under approved procedures in a rate-based emission standards plan or represents quantified and verified MWh energy generation or energy savings achieved by an approved state measure in a state measures plan.

[942] For example, under a rate-based emission standard with credit trading, ERCs may be issued for qualifying actions that occur both inside and outside the state, provided the measures meet requirements of EPA-approved state regulations and the provider applies to the state for the issuance of ERCs. Similarly, under a state measures plan, a state might include state requirements such as an RPS, where compliance with the RPS can be met through out-of-state RE generation.

These criteria are intended to address the fact that eligible measures should lead to substitution of generation from affected EGUs, with related impacts on CO_2 emissions from affected EGUs. Where states with mass-based plans implement mass-based CO_2 emission standards, CO_2 emissions reductions from affected EGUs must occur in order to comply with these emission standards and, unlike the rate-based approach, zero- and low-emitting MWhs do not play a specified role in demonstrating that the mass-based standards have been met.[943] Since they are not counted in the mass-based demonstration, eligible measures located in mass-based states could be used in a state with a rate-based plan to adjust the CO_2 emission rate of affected EGUs. Such adjustments would obviate the need for comparable CO_2 emission reductions at affected EGUs in the rate-based state or the use of other measures to make a rate adjustment. In this scenario, to the extent that eligible measures substitute solely for generation from affected EGUs in a state with mass-based emission limits, and are also used to adjust the reported CO_2 emission rate of affected EGUs in a rate-based state, no incremental CO_2 emissions reductions would occur in the rate-based state as a result of the eligible measures.[944] The result would be forgone CO_2 emission reductions that would otherwise occur across the two states. These dynamics are further addressed in section VIII.L.

For RE measures located in a mass-based state to have some or all of its generation counted under a rate-based plan in another state, it must be demonstrated that the generation was delivered to the grid to meet electricity load in a state with a rate-based plan.[945] Some examples of documentation that can serve as a demonstration include a power delivery contract or power purchase agreement. The EPA is giving states flexibility regarding the nature of this demonstration, but a state plan must describe the nature of the required demonstration and have it be approved by the EPA.

Under an emission standards plan, this demonstration must be made by the provider of the RE measure seeking ERC issuance under the rate-based emission standards in a rate-based state, as part of the eligibility application for the measure.[946] The rate-based state must include in its state plan provisions that describe a sufficient demonstration of geographic eligibility for the RE generation under rate-based emission standards.

Further examples of eligible demonstrations and how they should be outlined in state plans are provided in section VIII.L.

(ii) *Measures that occur in states, including areas of Indian country, that do not have affected EGUs.*

States, including areas of Indian country, that do not have any affected EGUs within their borders may be providers of credits for generation from zero- or low-emitting resources to adjust CO_2 emission rates. In its supplemental proposal for the proposed rulemaking, the EPA sought comment on whether or not jurisdictions without affected fossil fuel generation units subject to the proposed emission guidelines should be authorized to participate in state plans. Commenters were supportive of allowing those jurisdictions without affected EGUs the opportunity to participate in state plans. CO_2 reduction measures in areas without affected EGUs have the potential to provide cost-effective opportunities to reduce emissions and should be available on a voluntary basis to affected EGUs. Commenters noted that some tribes, for example, have many untapped RE resources that could be developed, and they should be able to realize the benefits of contributing to a state plan. Commenters stated that because of the integrated nature of the U.S. electricity grid, it is appropriate to allow all jurisdictions with the ability to contribute to and benefit from CO_2 emission reductions or CO_2 emission rate adjustments.

For participating states, they must adhere to EM&V standards, installation dates, and any other criteria that apply to all states. Section VIII.K.3 below identifies and discusses the EM&V requirements used to quantify MWh savings from generation from zero- or low-emitting sources.

States, including areas of Indian country, that do not have any affected EGUs may provide ERCs to adjust CO_2 emissions provided they are connected to the contiguous U.S. grid and meet the other requirements for eligibility. To qualify for ERCs from zero or low-emitting resources, it must be demonstrated that the generation was delivered to the grid to meet electricity load in a state with a rate-based plan.[947] Some examples of documentation that can serve as a demonstration include a power delivery contract or power purchase agreement. The EPA is giving states flexibility regarding the nature of this demonstration, but a state plan must describe the nature of the required demonstration and have it be approved by the EPA.

In addition to generation from zero- or low-emitting resources, demand-side EE resources in areas of Indian country located within the borders of states with rate-based emission standards for affected EGUs may also be issued ERCs. In these instances, the area of Indian country is located within the rate-based service area subject to a rate-based state plan. The ERCs from demand-side EE resources must meet the eligibility requirements to adjust a CO_2 emission rate, including installation date and EM&V requirements described below in section VIII.K.3. If the area of Indian country is located within the borders of a state that is meeting a mass-based CO_2 goal, then the demand-side EE resources are not eligible to be issued ERCs. Similarly, demand-side EE resources in any state with a mass-based CO_2 goal are not eligible to provide ERCs.

Non-contiguous states and territories may not be providers of ERCs to the contiguous U.S. states. As discussed previously in section VII.F, we have not set CO_2 emission performance goals for Alaska, Hawaii, Guam, or Puerto Rico in this final rule at this time.

(iii) *Measures that occur outside the U.S.*

The EPA will work with states using the rate-based approach that are interested in allowing the use of RE from outside the U.S. to adjust CO_2 emission rates. In these cases, all conditions for creditable domestic RE must be met, including that RE resources must be incremental and installed after 2012, and all EM&V standards must be met. In addition, the country generating the ERCs must be connected to the U.S. grid, and there must be a power purchase agreement or other contract for delivery of the power with an entity in the U.S. RE generation capacity outside the U.S. that existed prior to 2012 but was not exported to the U.S. is not considered new or incremental generation and, therefore,

[943] Where such measures substitute for generation from affected EGUs subject to a mass CO_2 emission limit, such measures reduce the cost of meeting those mass emission limits, but do not result in incremental CO_2 emission reductions.

[944] As used here, incremental emission reductions refers to emission reductions that are above and beyond what would be achieved solely through compliance with the emission standards in the mass-based state.

[945] This does not need to necessarily be the state where the MWh of energy generation from the measure is used to adjust the CO_2 emission rate of an affected EGU.

[946] Requirements for ERC issuance are addressed in section VIII.K.2.

[947] This does not need to necessarily be the state where the MWh of energy generation from the measure is used to adjust the CO_2 emission rate of an affected EGU.

not eligible for adjusting CO_2 emission rates under this rule. For example, a new transmission interconnection to existing RE in Canada would not be considered incremental, but a new interconnection to RE where the RE was built after 2012 would be considered incremental. See below in section VIII.K.1.a.(3) for more specifics regarding the use of incremental hydroelectric power in a rate-based approach.

The EPA received comments encouraging the use of international zero-emitting electricity imports in state plans, particularly hydroelectric power from Canada. Canada currently provides states such as Minnesota and Wisconsin with RE through existing grid connections. New projects are in various stages of development to increase generating capacity, which could be called upon as a base load resource to supplement variable forms of RE generation. Commenters said that the EPA should permit the use of all incremental hydropower—both domestic and international—towards EGU CO_2 emission rate adjustments providing that double-counting can be prevented; and the EPA acknowledges this may be allowable, as long as the specified criteria have been met.

(3) *RE.*

RE measures may be used to adjust a CO_2 emission rate, provided they meet the general eligibility requirements outlined above and the MWh electricity generation is properly quantified and verified.[948] As used in this section, RE includes electric generating technologies using RE resources, such as wind, solar, geothermal, hydropower, biomass and wave and tidal power. A capacity uprate at an existing RE facility (*i.e.,* an uprate to generating capacity originally installed as of 2012 or earlier) is eligible to adjust a CO_2 emission rate. The capacity uprate must occur after 2012. Such uprates to capacity represent incremental capacity added after 2012.

Quantification and accounting criteria for incremental RE (and nuclear generation) are as follows. The incremental generating capacity (in nameplate MW) is divided by the total uprated generating capacity (in nameplate MW) and then multiplied by generation output (in MWh) from the uprated generator. For example, if a hydroelectric power plant expands generating nameplate capacity from 100 MW to 125 MW and generation output increased to 1,000 MWh, then 200 MWh ((25 MW/125 MW) * 1,000 MWh) is eligible for use in adjusting a CO_2 emission rate, regardless of the overall level of generation for the period.[949]

Many commenters supported using RE deployment as measures to adjust the CO_2 emission rate of affected EGUs. Some commenters specifically agreed with the EPA's determination that only new and incremental RE (including hydropower) should be used to adjust CO_2 emission rates. Those commenters objected to counting existing RE that are already embedded in the baseline emissions and generation mix. A significant number of commenters supported the integration of RE into a rate-based credit trading system.

Certain additional requirements apply for hydropower and biomass (including waste-to-energy) RE, as described below.

(a) *Hydroelectric power.*

Consistent with other types of RE, new hydroelectric power generating capacity installed after 2012 is eligible for use in adjusting a CO_2 emission rate.

Relicensed facilities are considered existing capacity and, therefore, are not eligible for use in adjusting a CO_2 emission rate, unless there is a capacity uprate as part of the relicensed permit. In such a case, only the incremental capacity is eligible for use in adjusting a CO_2 emission rate.

The EPA noted that many commenters preferred that generation from hydropower displace generation from fossil sources. One commenter suggested that existing zero-emitting sources, including hydropower, do not reduce emissions from existing fossil generation, but that new or uprated zero-emitting sources would, because of their low variable rate, reduce fossil emissions. Several commenters recommended allowing incremental generation from new or uprated zero-emitting sources, including hydropower, be available for compliance.

(b) *Biomass.*

RE generating capacity installed after 2012 that uses qualified biomass as a fuel source is eligible for use in adjusting a CO_2 emission rate.[950] As discussed in section VIII.I.2.c., if a state intends to allow for the use of biomass as a compliance option for an affected EGU to meet a CO_2 emission standard, a state must propose qualified biomass feedstocks and treatment of biogenic CO_2 emissions in its plan, along with supporting analysis and quality control measures, and the EPA will review the appropriateness and basis for such determinations in the course of its review of a state plan. Where an RE generating unit uses qualified biomass, as designated in an approved state plan, MWh generation from the unit could be used to adjust the reported CO_2 emission rate of an affected EGU. Total MWh generation from an RE generating unit that uses qualified biomass must be prorated based on either the heat input supplied from qualified biomass as a proportion of total heat input or on the proportion of biogenic CO_2 emissions compared to total stack CO_2 emissions from the RE generating unit. Either approach must incorporate the approved valuation of biogenic CO_2 emissions from qualified biomass in the plan (*i.e.,* the proportion of biogenic CO_2 emissions from use of qualified biomass feedstock that would not be counted).

Section VIII.K describes the requirements and procedures for EM&V, and discusses how all eligible resources must demonstrate how they will quantify and verify MWh savings using best-practice EM&V approaches. One way to make this demonstration for eligible resources could be to use the presumptively approvable EM&V approaches that are included in the final model trading rule.

(c) *Waste-to-energy.*

Qualified biomass may include the biogenic portion of MSW combusted in a waste-to-energy facility.[951] With regard to assessing qualified biomass proposed in state plans, the EPA generally acknowledges the CO_2 emissions and climate policy benefits of waste-derived biomass, which includes biogenic MSW inputs to waste-to-energy facilities. The process and considerations for the use of biomass in state plans are discussed in section VIII.I.2.c.

MSW can be directly combusted in waste-to-energy facilities to generate electricity as an alternative to landfill disposal. In the U.S., almost all incineration of MSW occurs at waste-to-energy facilities or industrial facilities where the waste is combusted and energy is recovered.[952] Total MSW generation in 2012 was 251 million tons, but of that total volume generated, almost 87 million tons were recycled

[948] All state plans must demonstrate that measures included in the plan are quantifiable and verifiable. See section VIII.K.2 for discussion of requirements for the issuance of ERCs, and section VIII.K.3 for discussion of EM&V requirements for use of RE relied on in a state plan.

[949] For example, the overall generation from the uprated hydroelectric power plant may be higher or lower than generation levels that occurred at the plant prior to the capacity uprate.

[950] As with other RE, only generating capacity installed after 2012 would be eligible for use in adjusting a CO_2 emission rate.

[951] As with other RE, only generating capacity installed after 2012 would be eligible for use in adjusting a CO_2 emission rate.

[952] 2014 Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2012. *http://www.epa.gov/climatechange/ghgemissions/usinventoryreport.html.*

and composted.[953] Increasing demand for electricity generated from waste-to-energy facilities could increase competition for and generation of waste stream materials—including discarded organic waste materials—which could work against programs promoting waste reduction or cause diversion of these materials from existing or future efforts promoting composting and recycling. The EPA and many states have recognized the importance of integrated waste materials management strategies that emphasize a hierarchy of waste prevention, starting with waste reduction programs as the highest priority and then focusing on all other productive uses of waste materials to reduce the volume of disposed waste materials.[954] For example, Oregon and Vermont have strategies that emphasize waste prevention, followed by reuse, then recycling and composting materials prior to treatment and disposal.[955]

Information in the revised *Framework for Assessing Biogenic CO_2 Emissions from Stationary Sources* and other technical studies and tools (*e.g.,* EPA Waste Reduction Model, EPA Decision Support Tool) should assist both states and the EPA in assessing the role of biogenic feedstocks used in waste-to-energy processes, where use of such feedstocks is included in a state plan.[956]

When developing their plans, states planning to use waste-to-energy as an option for the adjustment of a CO_2 emission rate should assess both their capacity to strengthen existing or implement new waste reduction, reuse, recycling and composting programs, and measures to minimize any potential negative impacts of waste-to-energy operations on such programs. States must include that information in their plan submissions. The EPA will reject as qualified biomass any proposed waste-to-energy component of state plans if states do not include information on their efforts to strengthen existing or implement new waste reduction as well as reuse, recycling and composting programs, and measures to minimize any potential negative impacts of waste-to-energy operations on such programs. Only electric generation at a waste-to-energy facility that is related to the biogenic fraction of MSW and that is added after 2012 is eligible for use in adjusting a CO_2 emission rate.

A state plan must include a method for determining the proportion of total MWh generation from a waste-to-energy facility that is eligible for use in adjusting a CO_2 emission rate. The EPA will evaluate the method as part of its evaluation of the approvability of the state plan. Measuring the proportion of biogenic to fossil CO_2 emissions can be performed through sampling and testing of the biogenic fraction of the MSW used as fuel at a waste-to-energy facility (*e.g.,* via ASTM D–6866–12 testing or other methods—ASTM, 2012; Bohar, et al. 2010), or based on the proportion of biogenic CO_2 emissions to total CO_2 emissions from the facility. For an example of the former method, if the biogenic fraction of MSW is 50 percent by input weight, only the proportion of MWh output attributable to the biogenic portion of MSW at the waste-to-energy facility may be used to adjust an affected EGU CO_2 emission rate. Alternatively, as an example of the latter method, if biogenic CO_2 emissions represent 50 percent of total reported CO_2 emissions, a facility would need to estimate the fraction of biogenic to fossil MSW utilized and the net energy output of each component (based on relative higher heating values) to determine the percent of the MWh output from the waste-to-energy facility that may be used to adjust an affected EGU's CO_2 emission rate. Section VIII.K describes the requirements and procedures for EM&V, and discusses how all eligible resources must demonstrate how they will quantify and verify MWh savings using best-practice EM&V approaches. One way to make this demonstration for eligible resources could be to use the presumptively approvable EM&V approaches that are included in the final model trading rule.

The EPA received multiple comments supporting the use of waste-to-energy as part of state plans. Some commenters expressed concern that non-biogenic materials, such as plastics and metal, would be incinerated along with biogenic materials. As discussed above, only electric generation related to the biogenic fraction of MSW at a waste-to-energy facility added after 2012 is eligible for use in adjusting a CO_2 emission rate. The EPA also received comments that expressed concern about the potential negative impacts on recycling and waste reduction efforts, while other commenters asserted that waste-to-energy practices encourage recycling programs. Some commenters also expressed concern about what treatment would be approvable for emissions from waste-to-energy practices. As discussed above, potential negative impacts from waste-to-energy production on recycling, waste reduction, and composting programs should be evaluated and efforts to mitigate negative impacts must be discussed in the supporting documentation of state plans.

(4) *DSM.*

Avoided MWh that result from DSM may be used to adjust a CO_2 emission rate. Eligible DSM actions are those that are zero-emitting and avoid, rather than shift, the use of electricity by an electricity end-user.[957] The MWh that may be used for such an adjustment are determined based on the MW of demand reduction multiplied by the hours during which such a demand reduction is achieved (MW of demand reduction × hours = MWh avoided). DSM measures must be appropriately quantified and verified, in accordance with requirements in the emission guidelines, as discussed in section VIII.K.3.

(5) *Energy storage.*

Energy storage may not be directly recognized as an eligible measure that can be used to adjust a CO_2 emission rate, because storage does not directly substitute for electric generation from the grid or avoid electricity use from the grid.[958] The electric generation that is input to an energy storage unit may be used to adjust a CO_2 emission rate, but the output from the energy storage unit may not.[959] However, energy storage can be used as an enabling measure that facilitates greater use of RE, which can be used to adjust a CO_2 emission rate. For example, utility scale energy storage may be used to facilitate greater grid penetration of RE generating capacity and can also be used to store RE generation that may have otherwise been shed in times of excess generating capacity. Likewise, on-site energy storage at an electricity end-user can

[953] *http://www.epa.gov/osw/nonhaz/municipal/pubs/2012_msw_fs.pdf.*

[954] *http://www.epa.gov/wastes/nonhaz/municipal/hierarchy.htm.*

[955] *http://www.anr.state.vt.us/dec/wastediv/WastePrevention/main.htm.*

[956] *http://epa.gov/epawaste/conserve/tools/warm/Warm_Form.html, https://mswdst.rti.org/.*

[957] An example is a utility direct load control program, such as those where customer air conditioning units are cycled during periods of peak electricity demand. Actions that shift electricity demand from one time of day to another, without reducing net electricity use, are not eligible, as these measures do not avoid electricity use from the grid. Use of emitting generators as a DSM measure is also not eligible.

[958] Energy storage depends on a generation source, either from a utility-scale EGU (*e.g.,* a fossil EGU, a wind turbine, etc.) or a distributed generation source at an electricity end-user (*e.g.,* a PV system installed at a building).

[959] This approach focuses on counting the qualifying electric generation, which may be an input to an energy storage unit. Counting both the generation input to energy storage and the output from the energy storage unit would be a form of double counting. The electric generation that is stored may be counted; the subsequent output from the storage unit may not.

enable greater use of RE to meet on-site electricity demand.[960]

The EPA received multiple comments regarding the overall merits of energy storage. Consistent with the discussion above, the majority of commenters observed that storage technology enables greater grid penetration of RE and supports more efficient and effective operations of both RE and fossil-fuel plants. Commenters further noted that energy storage can provide RE to the grid when it is most needed, while simultaneously taking pressure off fossil-fuel plants to respond to sudden shifts in demand. Despite broad acknowledgment of the benefits of storage, public comments underscore its indirect and supporting role in providing zero-emission MWh to the grid (consistent with the EPA's decision to exclude energy storage as an eligible measure that can be used to adjust a CO_2 emission rate).

(6) *Transmission and distribution (T&D) measures.*

Electricity T&D measures that improve the efficiency of the T&D system and/or reduce electricity use may be used to adjust a CO_2 emission rate. This includes T&D measures that reduce losses of electricity during delivery from a generator to an end-user (sometimes referred to as ''line losses'' [961]) and T&D measures that reduce electricity use at the end-user, such as conservation voltage reduction (CVR).[962] The EPA received many comments in support of advanced energy technologies, including energy storage and transmission and distribution upgrades, and including these technologies in the suite of potential measures that states could consider for emission rate adjustments in their state plans. Comments pointed out that in addition to helping achieve emission standards, T&D efficiency improvements make the grid more robust and flexible, as well as delivering environmental benefits. In many parts of the country, grid operators, transmission planners, transmission owners and regulators are already taking steps to expand and modernize T&D networks. Commenters suggested that the EPA clarify the eligibility and criteria under which such measures would be permitted in a state plan.

To be eligible, T&D measures must be installed after 2012. This general eligibility requirement is discussed above in section VIII.K.1.a. The MWh of avoided losses or reduction in end-use that result from T&D measures must be appropriately quantified and verified, as discussed in section VIII.K.3.

(7) *Demand-side EE, including water system efficiency.*

Demand-side EE measures may be used to adjust a CO_2 emission rate, provided they meet the general eligibility requirements outlined above and the MWh electricity savings are properly quantified and verified.[963] As used in this section, demand-side EE may include a range of eligible measures, provided that the measures can be quantified and verified in accordance with the EM&V requirements in the emission guidelines, which are addressed in section VIII.K.3. Examples of demand-side EE measures include, but are not limited to, EE measures that reduce electricity use in residential and commercial buildings, industrial facilities, and other grid-connected equipment. Water efficiency programs that improve EE at water and wastewater treatment facilities also provide demand-side EE savings opportunities. EE measures, for the purposes of this section, may consist of EE measures installed as the result of individual EE projects, such as those implemented by energy service companies, as well as multiple EE measures installed through an EE deployment program (*e.g.* appliance replacement and recycling programs, and behavioral programs) administered by electric utilities, state entities, and other private and non-profit entities.[964] EE measures, for the purposes of this section, may also consist of state or local requirements that result in electricity savings, such as building energy codes and state appliance and equipment standards. Other interventions that result in electricity savings may also be considered an EE measure for the purposes of this section, provided the intervention can be specified and quantified and verified in accordance with EM&V requirements in the emission guidelines.

Numerous commenters expressed support for including demand-side EE as an eligible measure states and affected EGUs can use to meet the emission guidelines. Commenters touted the value of demand-side EE as a resource that delivers energy savings, lowers bills, creates jobs and reduces CO_2 emissions. Commenters called for the EPA to allow for the use of a broad range of demand-side EE measures to meet the emission guidelines, including, but not limited to, utility and non-utility EE deployment programs; energy savings performance contracts; measures that reduce electricity use in residential and commercial buildings, industrial facilities and other grid-connected equipment; state and local requirements that result in electricity savings, such as building energy codes and state appliance and equipment standards; appliance replacement and recycling programs; and behavioral programs. The EPA also received comments supporting the use of water sector EE programs and projects. Commenters identified water and wastewater utilities as particularly well-suited for participating in EE programs and providing a source of electricity savings. Investments such as replacing pumps and other aging equipment and repairing leaks can result in greater EE. The EPA agrees that these electricity savings should be eligible for adjustments to CO_2 emission rates at affected EGUs.

(8) *Nuclear power.*

As is discussed in section V.A.3, upon consideration of comments received, the EPA has not included nuclear generation from either existing or under construction units in the determination of the BSER. In addition to comments received on the provisions for determining the BSER, the EPA also received comments requesting that the EPA allow all generation from nuclear generating units to be recognized as an

[960] For example, battery storage at a building with solar PV can enable the PV system to meet the building's entire electrical load, by storing energy during times of peak PV system output for later use when the sun is not shining.

[961] T&D system losses (or ''line losses'') are typically defined as the difference between electricity generation to the grid and electricity sales. These losses are the fraction of electricity lost to resistance along the T&D lines, which varies depending on the specific conductors, the current, and the length of the lines. The Energy Information Administration (EIA) estimates that national electricity T&D losses average about 6 percent of the electricity that is transmitted and distributed in the U.S. each year.

[962] Volt/VAR optimization (VVO) refers to coordinated efforts by utilities to manage and improve the delivery of power in order to increase the efficiency of electricity distribution. VVO is accomplished primarily through the implementation of smart grid technologies that improve the real-time response to the demand for power. Technologies for VVO include load tap changers and voltage regulators, which can help manage voltage levels, as well as capacitor banks that achieve reductions in transmission line loss. VVO efforts are often closely related to CVR, which are actions taken to reduce initial delivered voltage levels in feeder transmission lines while remaining within the 114 volt to 126 volt range (for normal 120-volt service) required at the customer meter, per the ANSI C84.1 standards.

[963] All state plans must demonstrate that measures included in the plan are quantifiable and verifiable. See section VIII.K.2 for discussion of requirements for the issuance of ERCs, and section VIII.K.3 for discussion of EM&V requirements for use of demand-side EE relied on in a state plan.

[964] EE programs may also be implemented by other entities. Eligible EE measures that are deployed through EE programs are not limited to those EE measures deployed through EE programs administered by the types of entities listed here.

eligible measure that can be used to adjust a CO_2 emission rate. Commenters also recommended that the EPA consider nuclear generating units and RE generating units in a consistent manner for CO_2 emission rate adjustments in state plans. We agree with comments that nuclear generation and RE should be treated consistently when it comes to CO_2 emission rate adjustments.

The EPA has determined that generation from new nuclear units and capacity uprates at existing nuclear units will be eligible for use in adjusting a CO_2 emission rate, just like new and uprated capacity RE. However, consistent with the reasons discussed for not including the preservation of existing nuclear capacity in the BSER—namely, that such preservation does not actually reduce existing levels of CO_2 emissions from affected EGUs—preserving generation from existing nuclear capacity is not eligible for use in adjusting a CO_2 emission rate.

In contrast, any incremental zero-emitting generation from new nuclear capacity would be expected to replace generation from affected EGUs and, thereby, reduce CO_2 emissions; and the continued commitment of the owner/operators to completion of the new units and improving the efficiency of existing units through uprates can play a key role in state plans. Therefore, consistent with treatment of other low- and zero-emitting generation, new nuclear power generating capacity installed after 2012 and incremental generation resulting from nuclear uprates after 2012 are measures eligible for adjusting a CO_2 emission rate. However, existing nuclear units (*i.e.,* those that originally commenced operation in 2012 or earlier years) that receive operating license extensions are not eligible for use in adjusting a CO_2 emission rate, except where such units receive a capacity uprate as a result of the relicensing process. Only the incremental capacity from the uprate is eligible for use to adjust a CO_2 emission rate.

Applicable generation (in MWh) from incremental nuclear power is determined in the same manner as that described for incremental RE above.

(9) *Combined heat and power (CHP) units.*

Electric generation from non-affected CHP units [965] may be used to adjust the CO_2 emission rate of an affected EGU, as CHP units are low-emitting electric generating resources that can replace generation from affected EGUs. Electrical generation from non-affected CHP units that meet the eligibility criteria under section VIII.K.1.a can be used to adjust the reported CO_2 emission rate of an affected EGU.

Where a state plan provides for the use of electrical generation from eligible non-affected CHP units to adjust the reported CO_2 emission rate of an affected EGU, the state plan must provide a required calculation method for determining the MWh that may be used to adjust the CO_2 emission rate. This proposed accounting method must adequately address the considerations discussed below. The EPA will review whether a state's proposed accounting method for electric generation from eligible non-affected CHP units is approvable per the requirements of the final emission guidelines, as part of its overall plan review of the rate-based emission standards and implementing and enforcing measures in the state plan. The EPA notes that the proposed model rule for a rate-based emission trading program includes a proposed accounting method for non-affected CHP units. The accounting method provided in a final model rule could be a presumptively approvable accounting approach.

The proposed accounting method in a state plan must address the following considerations. The accounting approach proposed in a state plan must take into account the fact that a non-affected CHP unit is a fossil fuel-fired emission source, as well as the fact that the incremental CO_2 emissions related to electrical generation from a non-affected CHP unit are typically very low. In accordance with these considerations, a non-affected CHP unit's electrical MWh output that can be used to adjust the reported CO_2 emission rate of an affected EGU should be prorated based on the CO_2 emission rate of the electrical output associated with the CHP unit (a CHP unit's ''incremental CO_2 emission rate'') compared to a reference CO_2 emission rate. This ''incremental CO_2 emission rate'' related to the electric generation from the CHP unit would be relative to the applicable CO_2 emission rate for affected EGUs in the state and would be limited to a value between 0 and 1.

This low CO_2 emission rate for electrical generation from a non-affected CHP unit is a product of both the fact that CHP units are typically very thermally efficient and the fact that a portion of the CO_2 emissions from a non-affected CHP unit would have occurred anyway from an industrial boiler used to meet the thermal load in the absence of the CHP unit. In contrast, the CHP unit also provides the benefit of electricity generation while resulting in very low incremental CO_2 emissions beyond what would have been emitted by an industrial boiler. As a result, the accounting method proposed in a state plan should not presume that CO_2 emission reductions occur outside the electric power sector, but instead only would account for the CO_2 emissions related to the electrical production from a CHP unit that is used to substitute for electrical generation from affected EGUs.

Non-affected CHP units can use qualified biomass fuels. As described in section VIII.I.2.c, states must submit state plan requirements regarding qualified biomass feedstocks and treatment of biogenic CO_2 emissions in state plans, along with supporting analysis and quality control measures, and the EPA would review the appropriateness and basis for such determinations in the course of its review of the approvability of a state plan. Considerations for qualified biomass included in state plans are discussed in section VIII.I.2.c, while accounting requirements for RE using biomass are provided in section VIII.K.1.a.(3)(b).

Most comments received on CHP recommended that the EPA explicitly describe how CHP can be accounted for in a state plan. Commenters described the CO_2 emission reductions achieved through CHP's thermal efficiency and the precedent set in other federal and state rules that have included CHP as a compliance option. Some commenters pointed out that without such a description, states would not be able to readily take advantage of the CO_2 emission reductions that result from the use of CHP.

(10) *WHP.*

WHP units that meet the eligibility criteria under section VIII.K.1 may be used to adjust the CO_2 emission rate of an affected EGU. There are several types of WHP units. There are units, also referred to as bottoming cycle CHP units, where the fuel is first used to provide thermal energy for an industrial process and the waste heat from that process is then used to generate

[965] The accounting considerations described in this section are for a ''topping cycle'' CHP unit. A topping cycle CHP unit refers to a configuration where fuel is first used to generate electricity and then heat is recovered from the electric generation process to provide additional useful thermal and/or mechanical energy. A CHP unit can also be configured as a ''bottoming cycle'' unit. In a bottoming cycle CHP unit, fuel is first used to provide thermal energy for an industrial process and the waste heat from that process is then used to generate electricity. Some waste heat power (WHP) units are also bottoming cycle units and the accounting treatment for bottoming cycle CHP units is provided with the WHP description below.

electricity.[966] There are also WHP facilities where the waste heat from the initial combustion process is used to generate additional power. Under both configurations, unless the WHP unit supplements waste heat with fossil fuel use, there is no additional fossil fuel used to generate this additional power. As a result, there are no incremental CO_2 emissions associated with that additional power generation. As a result, the incremental electric generation output from the WHP facilities could be considered zero-emitting, for the purposes of meeting the emission guidelines, and the MWh of electrical output could be used to adjust the CO_2 emission rate of an affected EGU.[967] The MWh of electrical output from a WHP unit that can be recognized may not exceed the MWh of industrial or other thermal load that is being met by the WHP unit, prior to the generation of electricity.[968] Most commenters that addressed WHP noted the benefits of WHP at the same time that they discussed the benefits of CHP. The commenters reflected that WHP is another potential compliance option and requested it be discussed explicitly as a compliance option that can be used to meet the emission guidelines. The comments discussed WHP benefits but did not elaborate on a preferred accounting method for MWh of electrical generation from WHP that could be used to adjust the CO_2 emission rate of an affected EGU.

b. *Measures that may not be used to adjust a CO_2 emission rate.*

This section addresses measures that may not be used to adjust a CO_2 emission rate. New, modified, and reconstructed EGUs covered under the CAA section 111(b) final Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units rule are not approvable sources of electric generation for adjusting the CO_2 emission rate of an affected EGU under a rate-based state plan. As discussed earlier in section VII.D of this preamble, a key concern under this rule is leakage to new units that are not covered by the emission guidelines. Emissions leakage, or increased CO_2 emissions due to increased utilization of unaffected sources, is contradictory to objectives of this rule and should, therefore, be minimized. Allowing affected EGUs to adjust their emission rates as a result of lower-emitting new NGCC units not covered under this section 111(d) rule would not mitigate leakage concerns, and could even exacerbate the situation. Consequently, new EGUs covered under the CAA section 111(b) rule are not allowable measures in state plans because the EPA believes it would result in increased emission leakage.

The EPA received comments both supporting and opposing the use of new NGCC units in state plans. In addition to leakage concerns, commenters expressed concern with the potential incentives created by including new NGCC capacity in the BSER or as a compliance mechanism in state plans. Some commenters suggested that including new NGCC capacity in the BSER or for compliance would distort market incentives to build new NGCC units, particularly if new units were allowed to generate ERCs that could be sold to affected EGUs. These commenters suggested that the additional incentive for new NGCC units could make existing NGCC units less competitive. Other commenters suggested that including new NGCC capacity in state plans would promote generation from new CO_2-emitting units at the expense of new zero-emitting units, increasing overall emissions within a state. This effect would be exacerbated if state plans allowed new NGCC units to be treated as ''zero-emitting'' for purposes of compliance—as suggested by other commenters. In addition, commenters expressed concern that the EPA's inclusion of new NGCC capacity in setting the BSER or in compliance could negatively impact ratepayers over the long-term by sending the wrong signal to industry and resulting in stranded assets if, in the future, carbon emissions become more expensive or the EPA proposes to incorporate sources built under the forthcoming section 111(b) standard into the section 111(d) program. Commenters also expressed concern that including generation from new NGCC units could create unreasonable uncertainty, given limitations on the ability to accurately project new NGCC builds, could create undue pressure on natural gas prices, and could create unfair disparities in the compliance opportunities afforded different states. In light of the emissions leakage concerns, and in consideration of these comments, the EPA is not allowing shifting generation to new NGCC units to be used as a measure for adjusting CO_2 emission rates for affected EGUs in rate-based state plans.

In addition, other new and existing non-affected fossil fuel-fired EGUs that are not subject to CAA section 111(b) or 111(d), such as simple cycle combustion turbines, may not be used to adjust the CO_2 emission rate of an affected EGU. While generation from such units could substitute for generation from affected EGUs, the EPA has determined that additional incentives for such generation, in the form of an explicit adjustment to the CO_2 rate of an affected EGU, are not necessary or warranted. Providing for such an adjustment could create perverse incentives for the construction of new simple cycle combustion turbines that are not subject to the applicability criteria of the final Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units rule. These units could provide only limited adjustment credit, as operation beyond a certain capacity factor threshold would trigger applicability under CAA section 111(b). Further, providing for the ability to generate adjustment credits would provide incentives for construction of less efficient fossil generating capacity than would likely otherwise be constructed (*e.g.,* addition of a simple cycle combustion turbine rather than a NGCC unit). In addition, providing for the ability to generate adjustment credits could create perverse incentives for the continued operation of less efficient existing fossil generating capacity. Such outcomes run counter to the objectives of this final rule.

c. *Measures that reduce CO_2 emissions outside the electric power sector.*

Measures that reduce CO_2 emissions outside the electric power sector may not be counted toward meeting a CO_2 emission performance level for affected EGUs or a state CO_2 goal, under either a rate-based or mass-based approach, because all of the emission reduction measures included in the EPA's determination of the BSER reduce CO_2 emissions from affected EGUs. Examples of measures that may not be counted toward meeting a CO_2 emission performance level for affected EGUs or a state CO_2 goal include GHG offset projects representing emission reductions that occur in the forestry and agriculture sectors,[969] direct air capture,

[966] In such a configuration, the waste heat stream could also be generated from a mechanical process, such as at natural gas pipeline compressors.

[967] This only applies where no additional fossil fuel is used to supplement the use of waste heat in a WHP facility. Where fossil fuel is used to supplement waste heat in a WHP application, MWh of electrical generation that can be used to adjust the CO_2 emission rate of an affected EGU must be prorated based on the proportion of fossil fuel heat input to total heat input that is used by the WHP unit to generate electricity.

[968] This limitation prevents oversizing the thermal output of a WHP unit to exceed the useful industrial or other thermal load it is meeting, prior to generation of electricity.

[969] We note, however, that the final emission guidelines allow state measures like emission

Continued

and crediting of CO_2 emission reductions that occur in the transportation sector as a result of vehicle electrification.

2. Requirements for Rate-Based Emission Trading Approaches

As made clear in the proposal,[970] all emission standards in a state plan must be quantifiable, verifiable, enforceable, non-duplicative and permanent.[971] This requirement is applicable to emission standards that include a rate-based emission trading program. The State Plan Considerations TSD for the proposal also explained that in order to ensure a plan is enforceable, a state plan must: identify in its plan the entity or entities responsible for meeting compliance and other enforceable obligations under the plan; include mechanisms for demonstrating compliance with plan requirements or demonstrating that other binding obligations are met; and provide a mechanism(s) for legal action if affected EGUs are not in compliance with plan requirements or if other entities fail to meet enforceable plan obligations. A state plan using a rate-based emission trading approach must therefore include rate-based emission standards for affected EGUs along with related implementation and compliance requirements and mechanisms.[972] These related requirements include those applicable to rate-based emission standards more broadly: CO_2 emission monitoring, reporting, and recordkeeping requirements for affected EGUs, including requirements for monitoring and reporting of useful energy output. By satisfactorily addressing these requirements, state plans including a rate-based emission trading program will be able to meet the statutory requirements of CAA section 111(d) regarding the need for state plans to provide for the implementation and enforcement of emission standards, as well as meet the requirement that each emission standard be quantifiable, verifiable, non-duplicative, permanent, and enforceable with respect to each affected EGU.

The EPA also specifically proposed that for state plans that rely on measures that avoid EGU CO_2 emissions, such as RE and demand-side EE measures, the state will also need to include quantification, monitoring, and verification provisions in its plan for these measures. The EPA is finalizing requirements specific to rate-based emission trading programs as requirements the EPA has determined are necessary to assure the integrity of a rate-based approach that includes an emission trading program, and therefore assures a state plan using such an approach appropriately provides for the implementation and enforcement of rate-based emission standards in accordance with CAA section 111(d).[973] These specific requirements for a rate-based emission trading program include provisions for issuance of ERCs by the state and/or its designated agent; provisions for tracking ERCs, from issuance through submission for compliance; and the administrative process for submission of ERCs by the owner or operator of an affected EGU to the state, in order to adjust its reported CO_2 emission rate when demonstrating compliance with a rate-based emission standard.[974] These requirements must be submitted for inclusion in the federally enforceable plan, per the statutory requirement that states provide for the implementation and enforcement of emission standards. A rate-based trading program would provide for the implementation and enforcement of rate-based emission standards for a state plan that allows its affected EGUs to adjust a rate by the use of an ERC.

The EPA will review a state plan submittal including a rate-based emission trading program to assure that the plan contains the requirements necessary to assure the integrity of a rate-based approach, and therefore provide for the implementation and enforcement of rate-based emission standards. These requirements are discussed in more detail in this section.

The EPA also notes it is proposing model rules for both mass-based and rate-based emission trading programs. State plans that include the finalized model rule for a rate-based emission trading program could be presumptively approvable as meeting the requirements of CAA section 111(d) and these emission guidelines. The EPA would evaluate the approvability of such plans through independent notice and comment rulemaking.

A state may issue ERCs to an affected EGU that performs at a CO_2 emission rate below a specified CO_2 emission rate, as well as to providers of qualifying measures that provide substitute generation for affected EGUs or avoid the need for generation from affected EGUs. This latter category includes providers of qualifying RE and demand-side EE measures, as well as other types of measures, as discussed in section VIII.K.1.a.[975]

ERCs may be used by an affected EGU to adjust its reported CO_2 emission rate when demonstrating compliance with a rate-based emission standard. This adjustment is made by adding MWh to the denominator of an affected EGU's reported CO_2 emission rate, in the amount of submitted ERCs, resulting in a lower adjusted rate. To demonstrate compliance with a rate-based emission standard, an affected EGU would report its CO_2 lb/MWh emission rate to the state regulatory body, and would also surrender to the state any ERCs it wishes to use to adjust its reported emission rate. The state regulator would then cancel the submitted ERCs. The affected EGU would add the MWh the ERCs represent to the denominator of its reported CO_2 lb/MWh emission rate to demonstrate compliance with its emission standard. The state regulator could facilitate its evaluation of the affected EGU's compliance (as well as evaluation by the affected EGU, the EPA, and others) by providing functionality in its tracking system to run such compliance calculations. If the affected EGU's adjusted CO_2 emission rate is equal to or lower than its applicable emission rate standard, the affected EGU would be in compliance.

a. *Issuance of ERCs to affected EGUs.* ERCs may be issued to affected EGUs that emit below a specified CO_2 emission rate, as discussed below. For issuance of ERCs to affected EGUs, the state plan must specify the accounting method and administrative process for ERC issuance. This includes the

budget trading programs to include out-of-sector GHG offsets. For example, both the California and RGGI programs allow for the use of allowances awarded to GHG offset projects to be used to meet a specified portion of an affected emission source's compliance obligation. The RGGI program contains a cost containment allowance reserve that makes available additional allowances up to a certain amount, at specified allowance price triggers.

[970] 79 FR 34830, 34913.

[971] These requirements are described in detail in section VIII.D.2.

[972] As described below, these requirements would likely be provided in a state plan in the form of state regulations, but could potentially be provided in another form.

[973] By ''integrity of a rate-based emission trading program'', the EPA is referring to elements in the design and administration of a program necessary to assure that emission standards implemented using a rate-based emission trading approach are quantifiable, verifiable, enforceable, non-duplicative, and permanent.

[974] See section VIII.K.1 for a discussion of the accounting method used to adjust a CO_2 emission rate.

[975] As used in this section, the term ''EE program'' refers to an EE deployment program. An EE program involves deployment of multiple EE measures or EE projects, such as utility- or state-administered EE incentive programs that accelerate the deployment of EE technologies and practices. As used in this section, the term ''EE/RE project'' refers to a discrete EE project (*e.g.,* an EE upgrade to a commercial building or set of buildings) or a RE generator (*e.g.,* a single wind turbine or group of turbines).

calculation method for determining the number of ERCs to be issued to an affected EGU, based on reported CO_2 emissions and MWh energy output, in comparison to a reference CO_2 emission rate. The reference rate is a specified CO_2 lb/MWh emission rate that an affected EGU's reported CO_2 emission rate is compared to, when determining the amount of ERCs that may be issued to an affected EGU.

Following determination of the number of ERCs an affected EGU is eligible to receive, based on an affected EGU's reported CO_2 emission rate compared to a specified reference rate, the state regulatory body would issue those ERCs into a tracking system account held by the owner or operator of the affected EGU. Tracking system requirements are addressed below at section VIII.K.2.c.

The accounting method that may be applied in a state plan differs depending on whether a state plan includes a single rate-based emission standard that applies to all affected EGUs (*e.g.,* if a plan is designed to meet a state rate-based CO_2 goal) or separate rate-based emission standards that apply to subcategories of affected EGUs, namely fossil fuel-fired electric utility steam generating units and stationary combustion turbines. In both cases, ERCs are issued in MWh, based on the difference between an affected EGU's reported CO_2 emission rate (in CO_2 lb/MWh) and a specified CO_2 lb/MWh emission rate that the reported rate is compared to (referred to as a ''reference rate''). The reference rate may be an affected EGU's assigned CO_2 emission limit rate or another CO_2 emission rate, as described below. Where an affected EGU's reported CO_2 emission rate is lower than the specified reference CO_2 emission rate, ERCs may be issued.

Where a state plan includes emission standards in the form of a single rate-based emission standard that applies to all affected EGUs, the reference rate is the CO_2 emission rate limit for affected EGUs. In this instance, ERCs may be issued based on an affected EGU's reported CO_2 emission rate as a proportion of the emission limit rate. For example, if the emission rate limit is 2,000 lb CO_2/MWh and the affected EGU emits at a rate of 1,000 lb CO_2/MWh, 0.5 MWh would be awarded for every MWh generated by the affected EGU. ERCs would be issued to affected EGUs in whole MWh increments. The calculation method is as follows:

ERCs [976] = reported MWh by affected EGU [977] × ((CO_2 emission rate limit for affected EGUs [978]—affected EGU reported CO_2 emission rate [979])/CO_2 emission rate limit for affected EGUs)

For the example above, the calculation is as follows:

ERCs = MWh reported × (2,000 − 1,000)/2,000 = MWh reported × 0.5

If the affected EGU in this example generated 1,000,000 MWh, 500,000 ERCs would be issued.

Where a state plan includes separate emission standards for subcategories of affected EGUs, specifically affected fossil fuel-fired electric utility steam generating units and stationary combustion turbines, the reference rate differs for affected fossil fuel-fired electric utility steam generating units and stationary combustion turbines. Additionally, if the state plan applies emission standards for its affected EGUs that are equal to the subcategorized CO_2 emission performance rates there is a unique opportunity for the adjustment of an affected EGU's emission rate using ERCs that are generated as a result of building block 2 incremental NGCC unit operation. The EPA is requiring state plans to account for incremental NGCC generation in ERC generation if a state plan applies the subcategorized CO_2 emission performance rates to its affected EGUs as emission standards. Additionally, the EPA is requiring that a NGCC unit is not able to use ERCs generated by it or any other NGCC unit's building block 2 incremental generation.

For affected steam generating units, the reference CO_2 emission rate is the assigned CO_2 emission rate limit for steam generating units, and the following accounting method for generating ERCs applies:

ERCs [980] = reported MWh × ((steam generating unit CO_2 emission rate limit [981]—steam generating unit reported CO_2 emission rate)/steam generating unit CO_2 emission rate limit).

For an affected NGCC stationary combustion turbine in a subcategorized rate-based emission trading program, the following equation provides a required accounting method for generating ERCs based on operation with respect to the NGCC unit's emission standard:

ERCs = NGCC unit's reported MWh—((NGCC unit's CO_2 emission standard [982]—NGCC unit's reported CO_2 emission rate)/NGCC unit's CO_2 emission standard)

According to this equation, ERC issuance is assessed based on the difference between the CO_2 emission rate standard for the NGCC unit [983] and the reported CO_2 emission rate of the affected NGCC unit. In other words, affected NGCC stationary combustion turbines earn ERCs for generation when they perform at an emission rate better than the reference rate for stationary combustion turbines, similarly to how affected steam units can earn ERCs.

In a subcategorized rate-based emission trading program, a state must use the incremental operation of an affected NGCC unit quantified for building block 2 to allow a NGCC unit to generate ERCs based on its expected incremental generation.

A state plan that provides for the use of ERCs issued based on incremental affected NGCC generation must provide a required calculation method that allows for issuance of ERCs based on the ability of incremental generation from affected stationary combustion turbines to substitute for generation from affected steam generating units (as represented in building block 2), while also respecting the fact that affected stationary combustion turbines must also meet an assigned CO_2 emission rate limit for the entirety of its MWh energy output. This accounting method must reflect the application of the BSER, as described in section V, and the accounting method must not create incentives to rearrange dispatch between existing NGCC units to generate additional ERCs without changing the overall level of NGCC generation.

The EPA will review whether a state's accounting method is approvable per the requirements of the statute and this final rule as part of its overall plan review of the rate-based emission standards and implementing and enforcing measures in the state plan. The EPA notes that the proposed model rule for a rate-based emission trading program includes a proposed accounting method and takes comments on alternatives. The accounting method provided in a final model rule could be a presumptively approvable approach for issuance of ERCs based on the ability of incremental generation from affected stationary combustion turbines to

[976] For all calculations in this section, where the result is a negative value, no ERCs would be issued.

[977] This term represents the reported MWh by the affected EGU on an annual basis.

[978] This term represents the ''reference rate.''

[979] This term represents the annual reported CO_2 emission rate of the affected EGU.

[980] For all calculations in this section, where the result is a negative value, no ERCs would be issued.

[981] The ''reference rate.''

[982] The ''reference rate.''

[983] This is the CO_2 emission performance rate for affected stationary combustion turbines in the emission guidelines.

substitute for generation from affected steam generating units. A state's accounting requirements for generation of ERCs based on incremental affected NGCC generation must maintain consistency with the EPA's application of the BSER when calculating CO_2 emission performance rates for affected stationary combustion turbine and steam generating units. In particular, a state's accounting method must maintain consistency of accounting in a state rate-based CO_2 emission standard with the EPA's application of building block 2 in calculating CO_2 emission performance rates for affected fossil fuel-fired electric utility steam generating units and stationary combustion turbines, which is based on use of incremental generation from affected stationary combustion turbine to replace generation from affected steam generating units.

b. *Issuance of ERCs for RE, demand-side EE, and other measures.*

ERCs may be issued for qualifying measures.[984] For issuance of ERCs for qualifying measures, state plan requirements for ERC issuance must include a two-step process. In the first step of the process, a potential ERC provider submits an eligibility application for a qualifying program or project [985] to the administering state regulator (or its agent [986]). The state regulator reviews the application to determine whether, in this example, an EE/RE program or project meets eligibility requirements for the issuance of ERCs.[987] An eligibility application must include a description of the program or project, a projection of the MWh generation or energy savings anticipated over the life of the program or project, and an EM&V plan that meets state plan requirements. The EM&V plan must describe how MWh of RE generation or energy savings resulting from the program or project will be quantified and verified.[988] A state, in its emission standard regulations, must include requirements for EM&V plans that are consistent with the requirements in the emission guidelines for EE/RE measures and other eligible measures, as discussed in sections VIII.K.1 and VIII.K.3.

The EPA has determined that state requirements for an eligibility application must include review of the application by an independent verifier, approved by the state as eligible per the requirements of the final emission guidelines to provide such verification, prior to submittal. This requirement builds on the approach used for assessing GHG offset projects, both in international emission trading programs and the GHG emission budget trading programs implemented by California and the RGGI participating states.[989] An assessment by an independent verifier would be included as a component of an eligibility application.

The EPA has determined that independent verification requirements are necessary to ensure the integrity of state rate-based emission trading programs included in a state plan, given the wide range of eligible measures that may generate ERCs and the broad geographic locations in which those measures may occur. Inclusion of an independent verification component provides technical support for state regulatory bodies to ensure that eligibility applications and M&V reports are thoroughly reviewed prior to issuance of ERCs. Inclusion of an independent verification component is also consistent with similar approaches required by state PUCs for the review of demand-side EE program results and GHG offset provisions included in state GHG emission budget trading programs.

State plans with rate-based emission trading programs must include requirements regarding the qualification status of an independent verifier. An independent verifier is a person (including any company, any corporate parent or subsidiary, any contractors or subcontractors, and the actual person) who has the appropriate technical and other qualifications to provide verification reports. The independent verifier must not have, or have had, any direct or indirect financial or other interest in the subject of its verification report or ERCs that could impact its impartiality in performing verification services. State plans must require that a person be approved by the state as an independent verifier, as defined by this final rule, as eligible to perform the verifications required under the approved state plan. State plans must also include a mechanism to temporarily or permanently revoke the qualification status of an independent verifier, such that it can no longer provide verification services related to an eligibility application or M&V report for at least the duration of the period it does not meet the qualification requirements for independent verifiers in an approved state plan. The EPA's proposed model rate-based emission trading rule contains provisions addressing accreditation and conflicts of interest for independent verifiers. State plans that adopt the finalized model rule could be presumptively approvable with respect to these requirements regarding independent verifiers.

The state's eligibility requirements and application procedures must ensure that only eligible actions may generate ERCs and that documentation is submitted only once for each program or project, and to only one state program.[990] These provisions will ensure that actions that are eligible for the issuance of ERCs are ''non-duplicative.'' [991] The tracking system used to administer a state's rate-based emission trading system must provide transparent, electronic, public access to information about program and project eligibility applications, including EM&V plans, and regulatory approval status.

In the second step of the process, following implementation of the RE/EE program or project (as described in this example) that was approved in step one, the RE/EE provider periodically submits a M&V report to the state regulatory body documenting the results of the

[984] Qualifying measures that can be used to adjust the CO_2 emission rate of an affected EGU are discussed at section VIII.K.1, and include incremental NGCC, RE, demand-side EE, and other measures, such as DSM, CHP and incremental nuclear generation.

[985] For example, for an EE/RE program or project, as described in this section for illustrative purposes. The requirements described in this section for EE/RE programs and projects also apply for all other eligible qualifying measures discussed in section VIII.K.1.

[986] As used here, an agent is a party acting on behalf of the state, based on authority vested in it by the state, pursuant to the legal authority of the state. A state could designate an agent to provide certain limited administrative services, or could choose to vest an agent with greater authority. Where an agent issues an ERC on behalf of the state, such issuance would have the same legal effect as issuance of an ERC by the state.

[987] The entity implementing the EE/RE program or project (referred to in the preamble as a ''provider'') would submit the application. This is the identified entity to which ERCs would ultimately be issued, to a tracking system account held by the entity. Such entities could include a wide variety of parties that implement EE/RE programs and projects, including owners or operators of affected EGUs, electric distribution companies, independent power producers, energy service companies, administrators of state EE programs, and administrators of industrial EE programs, among others.

[988] The verification process includes confirmation that quantified MWh are non-duplicative and permanent (*i.e.,* are not being used in any other state plan to demonstrate compliance with an emission standard or achievement of an emission performance rate or state CO_2 emission goal).

[989] Information about the verification process for GHG offsets under the RGGI program, including verifier accreditation requirements and access to relevant documents, is available at *http://www.rggi.org/market/offsets/verification.* Similar information about the verification process for GHG offsets under the California program is available at *http://www.arb.ca.gov/cc/capandtrade/offsets/verification/verification.htm.*

[990] This includes ensuring that multiple parties do not submit an eligibility application for the same EE program or project, or for the same RE generator.

[991] Emission standards must be ''non-duplicative'' as described in section VIII.D.2.

program or project in MWh of electric generation or energy savings.[992] These results are quantified according to the EM&V plan that was approved as part of step one. These results are verified by an accredited independent verifier, and its verification assessment must be included as part of the M&V report submitted to the state regulatory body. The administering state regulator (or its agent) then reviews the M&V report, and determines the number of ERCs (if any) that should be issued, based on the report. Finally, the state regulatory body (or its agent) issues ERCs to the provider of the approved program or project. These ERCs are issued to the tracking system account held by the program or project provider.

State plan requirements must ensure that only one ERC is issued for each verified MWh. This is addressed through registration in the tracking system of programs and projects that have been qualified for the issuance of ERCs, to ensure that documentation is submitted only once for each RE/EE action, and to only one state program.[993] The tracking system must provide transparent electronic public access to submitted M&V reports and regulatory approvals related to such reports.[994] Such reports are the basis for issuance of ERCs.

c. *Tracking system requirements.*

State requirements must include provisions to ensure that ERCs issued to any eligible entity are properly tracked from issuance to submission by affected EGUs for compliance (where ERCs are ''surrendered'' by the owner or operator of an affected EGU and ''retired'' or ''cancelled''), to ensure they are only used once to meet a regulatory obligation. This is addressed through specified requirements for tracking system account holders, ERC issuance, ERC transfers among accounts, compliance true-up for affected EGUs,[995] and an accompanying tracking system that meets requirements specified in the emission trading program regulations. Each issued ERC must have a unique identifier (*e.g.,* serial number) and the tracking system must provide for traceability of issued ERCs back to the program or project for which they were issued.

The EPA received a number of comments from states and stakeholders about the value of the EPA's support in developing and/or administering tracking systems to support state administration of rate-based emission trading systems. This could include regional systems and/or a national system. The EPA is exploring options for providing such support and is conducting an initial scoping assessment of tracking system support needs and functionality.

d. *Effect of improperly issued ERCs.*

Because the goal of this rulemaking is the actual reduction of CO_2 emissions, it is fundamental that ERCs represent the MWh of energy generation or savings they purport to represent. To this end, only valid ERCs that actually meet the standards articulated in this rule may be used to satisfy any aspect of compliance by an affected EGU with emission standards. Despite safeguards included in the structure of ERC issuance and tracking systems, such as the review of eligibility applications and M&V reports, and state issuance of ERCs, ERCs may be issued that do not, in fact, represent eligible zero-emission MWh as required in the emission guidelines. A variety of situations may result in such improper ERC issuance, ranging from simple paperwork errors to outright fraud.

An approvable state plan that allows affected EGUs to comply with their emission standards in part through reliance on ERCs must include provisions making clear that an affected EGU may only demonstrate compliance with an ERC that represents the one MWh of actual energy generation or savings that it purports to represent and otherwise meets the emission guidelines.

e. *Banking of ERCs.*

ERCs issued in 2022 or a subsequent year may be carried forward (or ''banked'') and used for demonstrating compliance in a future year.[996] For example, an ERC issued for a MWh of RE generation that occurs in 2022 may be applied to adjust a CO_2 emission rate in 2023 or future years without limitation. ERCs may be banked from the interim plan performance period to the final plan performance period. Banking provides a number of advantages while ensuring that the same output-weighted average CO_2 emission rates of the interim and final state CO_2 goals are achieved over the course of a state plan. Banking provisions have been used extensively in rate-based environmental programs and mass-based emission budget trading programs.[997] This is because banking reduces the cost of attaining the requirements of the regulation. The EPA has determined that the same rationale and outcomes apply under a CO_2 emission rate approach, in that allowing banking will reduce compliance costs. Banking encourages additional emission reductions in the near-term if economic to meet a long-term emission rate constraint, which is beneficial due to social preferences for environmental improvements sooner rather than later.[998] State plans must specify whether the state is allowing or restricting the banking of ERCs between compliance periods for affected EGUs. State plans must also prohibit borrowing of any ERCs from future compliance periods by affected EGUs or eligible resources.

f. *Considerations for ERC issuance.*

The EPA notes that state-administered and state-overseen EE programs, such as those administered by state-regulated electric distribution utilities, could play a key role in supplying energy savings to a rate-based emission trading system in the form of ERCs. These programs have been the primary means for delivering EE programs and energy savings at scale, and also allow for a state to conduct a portfolio planning process to guide EE program design and focus in a manner that best provides multiple benefits to electricity ratepayers in a state. Such portfolio planning processes typically treat EE as an energy resource comparable to electricity generation.

[992] State rate-based emission trading program regulations must specify the frequency for submission of M&V reports for approved qualified measures that have been deemed eligible to generate ERCs. These reporting periods should be annual, but a state could consider shorter or longer periods, depending on the type of ERC resource.

[993] EE/RE programs and projects, and other eligible measures, with an approved eligibility application would be designated in a tracking system as qualified programs or projects. Qualified programs and projects may be issued ERCs, based on approved M&V reports.

[994] This must include electronic Internet access to such information in the tracking system.

[995] ''Compliance true-up'' refers to ERC submission by an owner or operator of an affected EGU to adjust a reported CO_2 emission rate, and determination of whether the adjusted rate is equal to or lower than the applicable rate-based emission standard.

[996] States also have the option to participate in the CEIP, under which they can issue ERCs for MWh generation or savings that occur in 2020–2021 for measures implemented following submission of a final state plan, and receive matching ERCs from a federal pool. See section VIII.B.2 for a detailed discussion. The ERCs issued under this program can also be banked during and between the interim and final compliance period.

[997] Banking under mass-based emission budget trading programs, and the rationale for banking provisions, is addressed below in section VIII.J.2.c.

[998] The absence of banking creates an incentive to defer both relatively low-cost and higher-cost CO_2 emission reduction actions until a later period when emission rate limits become more stringent, rather than incentives to undertake the low-cost activities sooner in order to further delay the high cost actions. Under a rate-based emission trading program, banking will encourage ERC providers to generate larger numbers of ERCs in early years of a plan performance period, in anticipation of rising ERC prices over time, when demand for ERCs is expected to increase as rate-based CO_2 emission standards become more stringent.

The EPA also notes that non–ERC certificates may be issued by states and other bodies for MWh of energy generation and energy savings that are used to meet other state regulatory requirements, such as state RPS and EERS, or by individuals to make environmental or other claims in voluntary markets.

The EPA defines an ERC in the emission guidelines as a tradable compliance instrument that represents a zero-emission MWh (for the purposes of meeting the emission guidelines) from a qualifying measure that may be used to adjust the reported CO_2 emission rate of an affected EGU subject to a rate-based emission standard in an approved state plan under CAA section 111(d). The sole purpose of an ERC is for use by an affected EGU in demonstrating compliance with a rate-based emission standard in such an approved state plan.

An ERC is issued separately from any other instruments that may be issued for a MWh of energy generation or energy savings from a qualifying measure. Such other instruments may be issued for use in meeting other regulatory requirements (*e.g.,* such as state RPS and EERS requirements) or for use in voluntary markets. An ERC may be issued based on the same data and verification requirements used by existing REC and EEC tracking systems for issuance of RECs and EECs.

The EPA notes that the definitions of other instruments, such as RECs, differ (as established under state statute, regulations, and PUC orders) and that requirements under state regulatory programs that use such instruments, such as state RPS, also differ. As a result, states may want to assess, when developing their state plan, how such existing instruments may interact with ERCs. For example, a state may want to assess how issuance of ERCs pursuant to a state plan may interact with compliance with a state RPS by entities affected under relevant state RPS regulations or PUC orders. The interaction of other instruments and ERCs may also impact existing or future arrangements in the private marketplace. Actions taken by states, separate from the design of their state plan, could address a number of these potential interactions. For example, state RPS regulations that specify a REC for a MWh of RE generation, and the attributes related to that MWh, may or may not explicitly or implicitly recognize that the holder of the REC is also entitled to the issuance of an ERC for a MWh of electricity generation from the eligible RE resource. This could impact existing and future RE power purchase agreements or REC purchase agreements. Such interactions among existing instruments and ERCs could also impact how marketing claims are made in the voluntary RE market. How a state might choose to address these potential interactions will depend on a number of factors, including the utility regulatory structure in the state, existing statutory and regulatory requirements for state RPS, and existing RE power purchase agreements and REC contracts.

g. *Program review.*

The EPA is requiring that states periodically review the administration of their rate-based emission trading programs. The results of these program reviews must be submitted by states to the EPA as part of their required reports on the implementation of their state plans, as described in sections VIII.D.a.(5) and VIII.D.2.b.(4), and must be made publicly available. Such a review submitted as part of a required state report provides for the implementation of rate-based emission standards per the requirements of CAA section 111(d)(2). For a rate-based emission trading program, the review must cover the reporting period addressed in the state's periodic reports to the EPA on plan implementation.

The program review must address all aspects of the administration of a state's rate-based emission trading program, including the state's evaluations and regulatory decisions regarding eligibility applications for ERC resources and M&V reports (and associated EM&V activities), and the state's issuance of ERCs. The program review must assess whether the program is being administered properly in accordance with the state's approved plan; whether ERC eligibility applications and M&V reports are being properly evaluated and acted upon (*i.e.,* approved or disapproved); whether reported annual MWh of generation and savings from qualified ERC resources are being properly quantified, verified, and reported in accordance with approved EM&V plans, and whether appropriate records are being maintained. The program review must also address determination of the eligibility of verifiers by the state and the conduct of verifiers, including the quality of verifier reviews. Where significant deficiencies are identified by the state's program review, those deficiencies must be rectified by the state in a timely manner.

States must collect, compile, and maintain sufficient data in an appropriate format to support the periodic program review. The EPA will review the results of each program review. The EPA may also audit a state's administration of its rate-based emission trading program and pursue appropriate remedies where significant deficiencies are identified.

3. EM&V Requirements for RE, Demand-Side EE, and Other Measures Used To Adjust a CO_2 Rate

This section discusses EM&V for RE, demand-side EE, and other measures that are used to generate ERCs or otherwise adjust an emission rate.[999] EM&V is applied for purposes of quantifying and verifying MWh in rate-based state plans, as described below. Rate-based state plans must require that eligible resources document in EM&V plans and M&V reports how all MWh saved and generated from eligible measures will be quantified and verified. Additionally, with respect to EM&V, the EPA's proposed model rule identifies certain industry best practices that, upon finalization, could be adopted as presumptively approvable components of a state plan.[1000]

As discussed in section VIII.K.1, quantified and verified MWh of RE generation, EE savings,[1001] and other eligible measures may be used to adjust a CO_2 emission rate when demonstrating compliance with the emission guidelines. In states implementing emission standard type plans with rate-based trading, affected EGUs adjust their reported emission rate using ERCs, which represent MWh that are quantified and verified according to the EM&V requirements described in this section. The EPA will evaluate the overall approvability of the state plan taking into consideration whether the state's submitted EM&V requirements satisfy these final emission guidelines.

a. *Discussion of proposed EM&V approach and public comment.*

The EPA proposed that a state plan that incorporates RE and demand-side

[999] EM&V is defined to mean the set of procedures, methods, and analytic approaches used to quantify the MWh from demand-side EE and RE and other measures, and thereby ensure that the resulting savings and generation are quantifiable and verifiable.

[1000] The EPA recognizes that EM&V best practices are routinely evolving to reflect changes in markets, technologies and data availability. Therefore the agency is providing draft EM&V guidance with the proposed model rule, which can be updated over time to address any such changes to best practices. The guidance can also identify and describe alternative quantification approaches that may be approved for use, provided that such approaches meet the requirements of the finalized EM&V requirements.

[1001] In the context of demand-side EE, ''measure'' refers to an installed piece of equipment or system at an end-use energy consumer facility, a strategy intended to affect consumer energy use behaviors, or a modification of equipment, systems or operations that reduces the amount of electricity that would have delivered an equivalent or improved level of end-use service in the absence of EE.

EE measures must include an EM&V plan that explains how the effect of these measures will be determined in the course of plan implementation. The proposal sought comment on the suitability of current state and utility EM&V approaches for RE and demand-side EE programs in the context of an approvable state plan, and on whether harmonization of state approaches, or supplemental actions and procedures, should be required in an approvable state plan, provided that supporting EM&V documentation meets applicable minimum requirements. In the proposal, the EPA also indicated that it would issue guidance to help states, sources, and project providers quantify and verify MWh savings and generation resulting from zero-emitting RE and demand-side EE efforts.

The proposal and associated ''State Plans Considerations'' TSD [1002] suggested that the EPA's EM&V requirements could leverage existing industry practices, protocols, and tracking mechanisms currently utilized by the majority of states implementing RE and demand-side EE. The EPA further noted that many state regulatory bodies and other entities already have significant EM&V infrastructure in place and have been applying, refining, and enhancing their evaluation and quality assurance approaches for over 30 years, particularly with regard to the quantification and verification of energy savings resulting from utility-administered EE programs. The proposal also observed that the majority of RE generation is typically quantified and verified using readily available, reliable, and transparent methods such as direct metering of MWh.

As a result, the agency took comment on whether this infrastructure is appropriate in the context of approvable state plans for use in rate-based state plans that include RE, demand-side EE, and other measures. The majority of commenters addressing this question responded affirmatively, indicating that existing EM&V infrastructure is appropriate to assure quality, credibility, and integrity. However, commenters also noted that EM&V methods are routinely improving and changing over time, and that the EPA's requirements and guidance should be responsive to such changes, should avoid locking in outdated methods, and should be updated to maintain relevance.

[1002] See discussion beginning on p. 34 of the State Plan Considerations TSD for the Clean Power Plan Proposed Rule: *http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule-state-plan-considerations*.

Another point made by commenters is that, despite the observed improvements in EM&V over time, quantification knowledge is more robust for some EE program and policy types than for others. Additionally, there is relatively limited experience applying EM&V protocols and procedures to emission trading programs, where each MWh of replaced generation can be bought and sold by a regulated source. As a result, the EPA's final emission guidelines and proposed model rule include a number of safeguards and quality-control features that are intended to ensure the accuracy and reliability of quantified EE savings.

b. *Requirements for EM&V and M&V submittals.*

As discussed in section VIII.K.2, these final guidelines require that state plans include a requirement that EM&V plans and M&V reports be submitted to the state for rate-based emission trading programs. States must require that at the initiation of an eligible measure, project providers must develop and submit to the state an EM&V plan that documents how requirements for quantification and verification will be carried out over the period that MWh generation or savings are produced. States must also require that after a project or program is implemented, the provider must submit periodic M&V reports to confirm and describe how each of the requirements was applied. These reports must also specify the actual MWh savings or generation results, as quantified by applying EM&V methods on a retrospective (ex-post) basis. States may not allow MWh values that are quantified using ex-ante (pre-implementation) estimates of savings. As previously described, the EPA took comment on the suitability of current state and utility EM&V approaches for RE and demand-side EE programs in the context of an approvable state plan. These final requirements regarding EM&V plans and M&V reports are intended to leverage and closely resemble those already in routine use.

For energy generating resources, including RE resources, states may leverage the programs and infrastructure they have in place for achievement of their RPS and take advantage of registries in place for the issuance and tracking of RECs. Many existing REC tracking systems already include well-established safeguards, documentation requirements, and procedures for registry operations that could be adapted to serve similar functions in relation to the final emission guidelines. For example, a key element of RPS compliance in many states that parallels the final rule's requirements is that each generating unit must be uniquely identified and recorded in a specified registry to avoid the double counting of credits at the time of issuance and retirement. In addition, the existing reports and documentation from tracking systems may, together with eligible independent third party verification reports, serve as the substantive basis for eligibility applications, EM&V plans and M&V reports for the issuance of ERCs to energy generating resources for affected EGUs to meet their obligations under the final rule. With respect to actual monitoring requirements, many existing REC registries include provisions for the monitoring of MWh of generation that would be appropriate to meet state plan requirements pursuant to the final rule, such as requirements to use a revenue quality meter.

For demand-side EE, states must require that EM&V plans that are developed for purposes of adjusting an emission rate under this final rule include several specific components. The EPA notes these components reflect existing provisions in a wide range of publicly or rate-payer funded EE programs and energy service company projects. One of these components state plans must require is a demonstration of how savings will be quantified and verified by applying industry best-practice protocols and guidelines, as well as an explanation of the key assumptions and data sources used. State plans must require EM&V plans to include and address the following:

- A baseline that represents what would have happened in the absence of the EE intervention, such as the equipment that would most likely have been installed—or that a typical consumer or building owner would have continued using—in a given circumstance at the time of EE implementation
- The effects of changes in independent factors affecting energy consumption and savings; that is, factors not directly related to the EE action, such as weather, occupancy, or production levels
- The length of time the EE action is anticipated to continue to remain in place and operable, effectively providing savings (in years)

Examples and discussion of industry best-practices for executing each of the above-listed components is provided in the EPA's draft EM&V guidance for demand-side EE, which is being released in conjunction with the proposed model rule. The model trading rule defines certain EM&V provisions for demand-side EE, as well as specific provisions for non-affected CHP and RE resources, including incremental hydroelectric power, biomass RE facilities, and waste-to-energy facilities, that may be presumptively approvable upon finalization.

The EPA notes that state plans incorporating the finalized model rule for rate-based emission trading programs could be presumptively approvable as meeting the requirements of CAA section 111(d) and the EM&V provisions in these emission guidelines. The EPA will evaluate the approvability of such state plans through independent notice and comment rulemaking.

c. *Skill certification standards.*

Using a skilled workforce to implement demand-side EE and RE projects and other measures intended to reduce CO_2 emissions, and to evaluate, measure, quantify and verify the savings associated with EE projects or the additional generation from performance improvements at existing RE projects are both important in existing best industry practices. Several commenters pointed out that skill certification standards can help to assure quality and credibility of demand-side EE, RE, and other CO_2 emission reduction projects. The EPA also recognizes that a skilled workforce performing the EM&V is important to substantiate the authenticity of emissions reductions.

The EPA is therefore recommending in conjunction with the EM&V requirements discussed in this section, that states are encouraged to include in their plans a description of how states will ensure that the skills of workers installing demand-side EE and RE projects or other measures intended to reduce CO_2 emissions as well as the skills of workers who perform the EM&V of demand-side EE and RE performance will be certified by a third party entity that:

(1) Develops a competency based program aligned with a job task analysis and certification scheme;

(2) Engages with subject matter experts in the development of the job task analysis and certification schemes that represent appropriate qualifications, categories of the jobs, and levels of experience;

(3) Has clearly documented the process used to develop the job task analysis and certification schemes, covering such elements as the job description, knowledge, skills, and abilities;

(4) Has pursued third-party accreditation aligned with consensus-based standards, for example ISO/IEC 17024.

Examples of such entities include: Parties aligned with the Department of Energy's (DOE) Better Building Workforce Guidelines and validated by a third party accrediting body recognized by DOE; or by an apprenticeship program that is registered with the federal Department of Labor (DOL), Office of Apprenticeship; or with a state apprenticeship program approved by the DOL, or by another skill certification validated by a third party accrediting body. This can help to substantiate the authenticity of emission reductions due to demand-side EE and RE and other CO_2 emission reduction measures.

4. Multi-State Coordination: Rate-Based Emission Trading Programs

Individual rate-based state plans may provide for the interstate transfer of ERCs, which would enable an ERC issued by one state to be used for compliance by an affected EGU with a rate-based emission standard in another state. Such plans would include regulatory provisions in each state's emission standard requirements that indicate that ERCs issued in other partner states may be used by affected EGUs for compliance. Such plans must indicate how ERCs will be tracked from issuance through use for compliance, through either a joint tracking system, interoperable tracking systems, or an EPA-administered tracking system.[1003]

The approaches described in this section are only allowed for states that impose rate-based emission limits for affected EGUs that are equal to the CO_2 emission performance levels in the emission guidelines. This approach is necessary to ensure that each state that is allowing for the interstate transfer of ERCs is implementing rate-based emission standards for affected EGUs at the same lb CO_2/MWh level.[1004] This assures that all the participating states are issuing ERCs to affected fossil steam and NGCC units that emit below their assigned emission standards on the same basis.

This approach avoids providing different incentives, in the form of issued ERCs, to affected steam generating units and NGCC units in different states that have comparable CO_2 emission rates. Providing different incentives to similar affected EGUs across states could create distortionary effects that lead to shifts in generation among states based on the different CO_2 emission rate standards applied by states to similar types of affected EGUs. Providing for the interstate trading of ERCs in this instance would exacerbate these distortionary effects by providing arbitrage opportunities.

When demonstrating that a state's CO_2 emission goal is achieved as a result of plan implementation, a state with linkages to other states would be required to demonstrate that any ERCs issued by another state that are used by affected EGUs in the state for compliance with its rate-based CO_2 emission standards were issued by states with an EPA-approved state plan.[1005]

States could implement these linkages among state plans with rate-based emission trading systems through three different implementation approaches: (1) Plans that are ''ready-for-interstate-trading;'' (2) plans that include specified bilateral or multilateral linkages; and (3) plans that provide for joint ERC issuance among states with materially consistent regulations. These approaches are summarized below:

- *Ready-for-interstate-trading plans:* A state plan recognizes ERCs issued by any state with an EPA-approved plan that also uses a specified EPA-approved[1006] or EPA-administered tracking system. Plans are approved individually. A state plan need not designate the individual states by name from which it would accept issued ERCs. States can join such a coordinated approach over time, without the need for plan revisions.[1007]
- *Specified bilateral linkage:* States recognize ERCs issued by named partner states. Partner states must demonstrate that they use a shared tracking system, interoperable tracking systems, or an EPA-administered tracking system. Plans are approved individually, including review of the shared tracking system or interoperable tracking systems.
- *Joint ERC issuance:* States implement materially consistent rate-based emission

[1003] The emission standards in each individual state plan must include regulatory provisions that address the issuance of ERCs and tracking of ERCs from issuance through use for compliance, as described in section VIII.K.2. The description here addresses how those regulatory provisions will be implemented through the use of a joint tracking system, interoperable tracking systems, or an EPA-administered tracking system.

[1004] States also have the option of implementing a multi-state plan with a single rate-based emission standard that applies to all affected EGUs in the participating states. This approach would also allow for interstate transfers of ERCs. Under this approach, a rate-based multi-state plan would include emission standards for affected EGUs based on a weighted average rate-based emission goal, derived by calculating a weighted average CO_2 emission rate based on the individual rate-based goals for each of the participating states and 2012 generation from affected EGUs.

[1005] This could be done by reference to data in the tracking system used to implement a state's rate-based emission trading program that identifies the origin of each ERC (*e.g.,* by serial identifier).

[1006] The EPA would designate tracking systems that it has determined adequately address the integrity elements necessary for the issuance and tracking of ERCs, as described in section VIII.K.2. Under this approach, a state could include in its plan such a designated tracking system, which has already been reviewed by the EPA.

[1007] The EPA notes that it is proposing a model rule for a rate-based emission trading program that could be used by states interested in implementing a ready-for-interstate-trading plan approach. A state plan that included the finalized rate-based model rule could be presumptively approvable as meeting the requirements of CAA section 111(d) and the emission guidelines. If a state plan also met the requirements described in this section for ready-for-interstate-trading plans, it could be approved as ready-for-interstate trading.

trading program regulations and share a tracking system. States coordinate their review of submissions for ERC issuance [1008] and their issuance of ERCs to the shared tracking system. Issued ERCs are recognized as usable for compliance in all states using the shared tracking system. Plans are approved individually, including review of the shared tracking system.

These implementation approaches are designed to streamline the process for linking emission trading programs, avoid or limit the need for plan revisions as new states join a collaborative emission trading approach, and facilitate the development of regional or broader multi-state markets for ERCs.[1009]

L. Treatment of Interstate Effects

This section discusses how differing characteristics across states and sources could create risks of increased emissions under this rule through double counting of emission reduction measures or through foregone emission reductions due to movement of generation from source to source. The section also discusses how the final rule addresses these concerns: First, through the characteristics of goal-setting and the framework of state plans, and second, through specific requirements intended to minimize the risk of double counting and increased emissions.[1010]

The section is structured as follows. First, this section discusses the dynamics that cause these risks to potentially arise. Second, it provides a discussion of how the risks of double counting and foregone reductions are minimized through the following provisions: The nature of the final emission performance rates, multi-state plan options that limit distortionary effects, the structure of mass-based plan and rate-based plan accounting for emission reductions measures, and specified restrictions on the counting in a rate-based plan of emission reduction measures located in a mass-based state. Finally, the section discusses how the rate-based accounting framework minimizes incentives to develop emission reduction measures in particular states due to differences in rates.

In the June 2014 proposal, the EPA acknowledged that emission reduction measures implemented under a state plan will likely have impacts across many affected sources both within and across state boundaries due to the dynamic and interstate nature of the electric grid. These interactions may be driven in part due to differences in power sector dynamics across states, including the types of affected EGUs in a state, the availability of eligible zero-emitting resources, and the costs of different compliance options and existing policies in states. These state-level characteristics play out across dynamic regional grids that provide electricity across states. EGUs are dispatched both within and across state borders and are constantly adjusting behavior in response to available generation and electricity demand on the regional grid. Whenever CO_2 emission reduction measures, such as RE or demand-side EE, are implemented, the measure can affect EGU generation and CO_2 emissions across the regional grid. These impacts can change across multiple affected EGUs on a minute-to-minute, hour-to-hour, and day-to-day basis as electricity demand changes and different generating resources are dispatched. These impacts will also change in the long-term, as the generating fleet and load behavior change over a period of years. Interactions among EGUs across states may be further driven by the plan types (*i.e.,* rate-based or mass-based) and the individual characteristics of the plans that states choose to adopt.

In the context of this complex environment of federal and state policies and interstate grids, commenters expressed concern about the risk of double-counting of measure impacts, particularly across state plans. Commenters stated that there is potential for distortionary incentives that could undermine overall CO_2 emission reductions (often termed emissions ''leakage''). Commenters requested that the EPA ensure that states avoid double-counting and minimize leakage effects when demonstrating achievement of state goals.

The EPA acknowledges that some amount of shifts in generation between sources within and across state borders will inevitably be present and unavoidable in the context of this rule and may affect how affected EGUs achieve the applicable CO_2 performance rates or state goals under a state plan. In fact, the definition of the BSER is premised upon shifts in generation across sources, particularly shifts from higher- to lower-emitting units that result in overall emission reductions. However, in the context of these shifts, the extent to which the movement of generation may be driven not by the potential to capture lower-cost emission reduction but by arbitrage across different emission rates, causing inefficiencies in the power markets and possibly eroding overall emission reductions, should be minimized.

In particular, the EPA has determined final emission performance rates that serve to reduce relative differences between state goals, and thus also focus the potential for generation shifting between affected EGUs on achieving the emission reductions quantified in the BSER. In the proposal, goals differed more substantially between states based upon an assessment of what emission reduction potential units could access located within their state. Commenters observed that due to the interconnected nature of the power sector, units are not limited to such emission reduction measures within their state, and indeed any operational decisions that units take necessarily influence operational decisions at other units throughout the interconnected grid. As a result, in the final rule, we are finalizing CO_2 emission performance rates, informed by regional emission reduction potential, for fossil fuel-fired electric utility steam generating units and stationary combustion turbines that are applied consistently across all affected EGUs. As the same source category-specific performance rates are applied to all units in the contiguous U.S. regardless of the state in which they are located, any differences between state goals in this final rule stem only from the relative prevalence in each state of fossil fuel-fired electric utility steam generating units and stationary combustion turbines. Consequently, there is substantially less incentive in this final rule for units to shift generation across state lines based solely on differences in state goals, since there is substantially less difference between the final rule's state goals, and since those state goals are themselves premised on nationally consistent

[1008] This refers to eligibility applications and M&V reports, which are required submittals for non-affected EGU entities seeking the issuance of ERCs. Where affected EGUs are issued ERCs for emission performance below a specified CO_2 emission rate, these ERCs are issued by the individual state in which they are subject to a rate-based emission standard. Requirements for ERC issuance are discussed in section VIII.K.2.

[1009] The EPA also notes that individual state plans may utilize RE and demand-side EE (and other eligible measures), that occur in other states, as described in section VIII.L addressing interstate effects. Under an individual state plan, ERCs could be issued for RE and demand-side EE measures that occur in other states, provided the EE/RE provider submits the measures to the state and the measures meet requirements in the state plan's rate-based emission trading program requirements. The multi-state approaches described above provide additional flexibility for states to informally and formally coordinate their implementation of rate-based plans across states while retaining individual rate-based state goals.

[1010] This section does not discuss emission leakage and how it is addressed by this final rule. See section VII.D for a discussion of emission leakage and its impact on state goal equivalence. See section VIII.J for a discussion of requirements for mass-based plans to address leakage.

source category-specific performance rates.

The EPA has also incorporated elements into the rule that seek to minimize double-counting and the distortionary effects that could potentially increase emissions. First, states have the option to adopt multi-state plans that reflect regional interactions while eliminating chances for double counting and providing a level playing field for trading of rate-based ERCs or mass-based allowances. Second, in the method for rate-based plan compliance, the rule provides a general accounting approach for adjusting an affected EGU's or state's CO_2 rate that inherently acts to minimize state differences. These points are further discussed below.

For both rate-based and mass-based approaches, the rule provides states with the option of creating either ''ready-for-interstate-trading'' plans or multi-state plans. These options for states working together provide opportunities to enable protections against double counting and minimize the presence of distortionary effects.

''Ready-for-interstate-trading'' and multi-state plans engage multiple states in the same system for the purpose of trading mass-based allowances or issuing and trading rate-based ERCs. This allows for efficient implementation of protections against double counting provided in state plan requirements, as multiple states are participating in the same tracking systems. This is particularly useful in the context of rate-based ERC issuance and tracking, where it must be ensured that the ERCs being generated are unique across rate-based plans.

This final rule also reduces distortionary effects within the context of multi-state plans. It does so by restricting states to interstate trading with equivalently denominated mass-based allowances or rate-based ERCs. In a mass-based context, all affected EGUs will trade uniform mass-based allowances, whether in a ''ready-for-interstate-trading'' plan or multi-state plan. In a rate-based plan context, ''ready-for-interstate-trading'' states must all adopt as their goal the CO_2 emission performance rates as their joint goal. This assures that all the participating states are issuing ERCs using the same subcategorized performance rates, and that the sources in each state have equivalent incentives for trading ERCs. Similarly, under multi-state plans, the relevant states must choose to adopt identical rates, either the CO_2 emission performance rates or a weighted average goal rate based on the rate-based goals of all the states involved. These requirements along with a method for calculating a weighted average goal rate are specified in section VIII.C.5.

Under all types of state plans, states must ensure that the emission reduction measures counted as part of meeting their plan requirements are not duplicative of any measures that are counted by another state, in order to avoid double counting of the MWhs of generation or energy savings that these measure produce. Depending on the accounting method used to reflect these measures in state goals, interstate effects could still allow for the double counting of the emission reductions resulting from these measures, particularly if mathematical adjustments were made to stack emissions to reflect these reductions. Depending on how these measures are accounted for, the reductions could be counted by both the state that deployed the measure, and the state that reports a reduction in fossil generation or reported emissions. In this final rule, the accounting approaches for both mass-based and rate-based plans have been specifically designed to eliminate the risk of double counting of reductions, because emission reduction measures are accounted for only through their inherent impact on stack emissions for affected EGUs.

Mass-based plans rely exclusively on reported stack emissions for determining whether a mass-based CO_2 emission goal is achieved. This means that under a mass-based plan any emission reduction measures that are implemented are automatically accounted for in reduced stack emissions of CO_2 from affected EGUs, which avoids concerns about counting the same mass reductions in two different mass-based states.

In a rate-based plan, there needs to be an explicit adjustment of reported CO_2 emission rates from affected EGUs, to reflect the measures that substitute low- or zero-emitting generation or energy savings for affected EGU generation. States with rate-based plans must demonstrate that measures used to adjust their CO_2 emission rate, such as RE and demand-side EE, are non-duplicative. The proposal attempted to address this issue in part by limiting demand-side EE that states could claim to in-state measures. In fact, those in-state measures still have an impact outside of the state and under the proposal's approach, states would have been restricted from taking credit for all the measures they have put in place that reduce CO_2 emissions. Therefore, the EPA is finalizing a treatment that allows states to count all in-state and out-of-state measures, while addressing interstate effects through the structure of the rule's accounting approach for adjusting the CO_2 emission rate of an affected EGU, detailed in section VIII.K.1 above, used to show that the state has met its obligation under its state plan.

The general accounting approach for adjusting the CO_2 emission rate of an affected EGU inherently accounts for the regional nature of how substitute generation and energy savings will impact affected EGU generation and CO_2 emissions. The following discussions refer to the substituting generation and energy savings in question as RE and demand-side EE, but this method can apply to other measures that were not included in the determination of the BSER that substitute for affected EGU generation. The adjusted CO_2 emission rate gives credit to the affected EGU or state for the MWhs of RE and demand-side EE it is responsible for deploying, by allowing those MWhs to be added to the denominator of the CO_2 rate, but makes no adjustment to the numerator. Instead, the numerator reflects reported stack emissions, which will reflect the extent to which RE and demand-side EE reduced the affected EGU's generation and emissions, without needing to account for the state in which the RE or demand-side EE originated, or approximating exactly how it impacted the regional grid. Double-counting of CO_2 emission reductions is prevented because the reported emissions from each unit are represented in the numerator of each of those units' emission rates, and those real emissions capture whatever emission reduction impact occurred with regard to any particular MWh of RE or demand-side EE. Because the general accounting approach disallows any adjustment to any EGU's reported emissions, it is not possible for the real emission reductions prompted by any particular measure to be double-counted.

Double-counting of MWhs in the denominator can be avoided because it is relatively straightforward to quantify the MWhs that the affected EGU is responsible for deploying and add them to the denominator, and this method aligns well with the MWh-denominated trading system described in this final rule. As long as it is assured that the MWhs of RE and demand-side EE are only being claimed by one affected EGU or state, as is outlined in section VIII.K, then there is no double-counting of MWh. Therefore, the accounting method avoids double counting of both CO_2 emission reductions and MWhs, the two characteristics of RE and demand-side EE measures that affect CO_2 emission rates. For further discussion of the

MWh-based accounting method, including a calculation example, see section VIII.K.1.

There may also be interactions between mass-based and rate-based plans regarding counting measures, specifically where measures that provide substitute or avoided generation, such as RE and demand-side EE, are located in a mass-based state and can also be used by a rate-based state in meeting the CO_2 performance rates or state goals. The EPA received comments on this particular issue, and many expressed concerns that this use of mass-based resources in a rate-based state would result in double-counting of emission reductions.

Commenters provided analyses specifying how two states can benefit from the same RE and demand-side EE measures as a result of rate- and mass-based plan interactions. Some commenters considered this double-counting of emission reductions, and requested specific mathematical adjustments of reported generation or CO_2 emissions from affected EGUs under either rate-based or mass-based state plans in order to eliminate double-counting.

The EPA has determined that, in the context of interactions among rate-based and mass-based plans, there is not explicit double-counting of the CO_2 emission reductions associated with counting measures located in mass-based states, considering the accounting methods outlined in this final rule. First, as discussed above, the accounting method for adjusting the CO_2 emission rate only counts the MWhs generated by a measure to adjust the MWh in the denominator of the reported CO_2 emission rate. The CO_2 emissions impacts of the measures will be reflected in the rate-based state only to the extent that the MWhs resulted in lower reported CO_2 emissions from an affected EGU in the rate-based state. To the extent that measures that provide substitute or avoided generation reduce generation from affected EGUs in a mass-based state, the effect of those measures is reflected in lower reported CO_2 emissions of the mass-based EGUs. The CO_2 emission reductions reflected in the rate and the mass state will necessarily be mutually exclusive, because both are based on reported stack emissions. Additionally, the mechanism in the mass-based state that is assuring CO_2 emission reductions is the mass budget, which is met by affected EGUs adjusting their generation. Low- or zero-emitting MWhs from resources like RE and demand-side EE can serve load in the mass-based state and play a role in lowering compliance costs, but they play no direct role in mass-based compliance. As a result, no double-counting of emission reductions can take place.

Though there is no risk of double-counting emissions, some commenters expressed the concern that overall CO_2 emissions reductions would be foregone in situations where a source in a rate-based state counts the MWh from measures in a mass-based state, but the generation from that measure acts solely to serve load in the mass-based state. In that scenario, expected CO_2 emission reduction actions in the rate-based state are foregone as a result of counting MWh that resulted in CO_2 emission reductions in a mass-based state. Therefore the EPA is restricting the ability of rate-based states to claim emission reduction measures, such as RE and demand-side EE, located in mass-based states.

While the EPA understands this concern regarding foregone reductions, we do not believe it is appropriate to restrict RE crediting unilaterally between rate-based and mass-based states. Such a restriction could cut some states off from regional RE supplies that are assumed in the BSER building block 3 and incorporated in the CO_2 emission performance rates and state CO_2 goals. Allowing crediting between rate- and mass-based states, as long as the risk of foregone CO_2 emission reduction actions in rate-based states are minimized, will assure a supply of eligible RE MWhs that will further enable affected EGUs and states to meet obligations under the final rule. Therefore, the EPA has determined that it is appropriate for rate-based states to count MWhs from RE located in mass-based states, subject to the condition that the generation in question was intended to meet electricity load in a state with a rate-based plan.[1011] This may apply to some or all of the generation from an individual RE installation. To assure that the RE generation in question meets this condition, the EPA is requiring that RE generation from RE installations located in a mass-based state can only be counted in a rate-based state if the electricity generated is delivered with the intention to meet load in a state with a rate-based plan, and was treated as a generation resource used to serve regional load that included the rate-based state. This can be demonstrated through, for example, the provision of a power delivery contract or power purchase agreement in which an entity in the rate-based state contracts for the supply of the MWhs in question. The EPA is providing flexibility to states regarding the nature of the required demonstration, though the state must specify eligible demonstrations for approval in state plans. Under an emission standards plan, this demonstration would be made by the provider of the measure seeking ERC issuance to the rate-based state.

The following are examples of how requirements for a demonstration could be established in state plans and used to allow RE in a mass-based state to be counted in a rate-based state. For an emission standards state plan, a state could specify in the regulations for the rate-based emission standards included in its state plan that it will require an RE provider that seeks the issuance of ERCs to show that load-serving entities in the rate-based state have contracted for the delivery of the RE generation that occurs in a mass-based state to meet load in a rate-based state. Under this approach, an RE provider in a mass-based state could submit as part of an eligibility application a delivery contract or power purchase agreement showing that the generation was procured by the utility, and was treated as a generation resource used to serve regional load that included the rate-based state. This documentation would be sufficient demonstration to allow the RE generating resource to meet this additional geographic eligibility requirement for the amount of generation in question. All quantified and verified RE MWhs submitted for ERC issuance would need to be associated with that power purchase contract or agreement, and this fact would need to be demonstrated in the M&V reports submitted for issuance of ERCs.

The ability for a rate-based state to count MWhs located in a mass-based state under the above conditions is limited to RE. Rate-based states are not allowed to claim demand-side EE or any other emission reduction measures that were not included in the determination of the BSER located in mass-based states for ERC issuance. While this limits rate-based sources' access to additional resources, providing that access would result in a risk of foregone reductions. Further, unlike RE, there is no obligation related to demand-side EE and other measures that were not included in the determination of the BSER incorporated in the CO_2 emission performance rates or state rate-based goals which would necessitate facilitating access to those resources. This treatment also does not apply to

[1011] This does not need to necessarily be the state where the MWh of energy generation from the RE measure is used to adjust the CO_2 emission rate of an affected EGU.

fossil-fuel fired EGUs, such as NGCC units. If a mass-based emission standard has been applied to an affected EGU, there is no valid way to calculate whether it has MWh that are eligible for crediting, as is possible under a rate-based plan.

Finally, as stated earlier, commenters also expressed concern about the potential for relative increases in emissions to occur given relative differences between sources and states. These differences could include states' goals under either the rate- or mass-based approaches, or states' accounting of new sources. These differences could induce increased generation in one state over another because the costs of compliance and relative costs of generation would vary between states. There was particular concern regarding how these differences would provide incentives for increasing generation at new fossil sources and expanding utilization of existing affected EGU generation in states that have less stringent goals, and that this movement of generation would result in increased emissions overall. This could potentially result in the achievement of performance rates but with fewer overall CO_2 emissions reductions than projected nationally under the proposal.

Commenters suggested that the issuance and trading of emission credits across states under a rate-based approach would result in incentives to create credits, through the development of RE for example, in certain states with higher state goals, and this could also be a source of increased overall emissions. They noted that RE siting would thus not occur in the most optimal locations. The commenters assumed that zero-emitting credits are denominated in mass units by multiplying the number of MWh by some emission rate: Either the state goal rate, the current state emission rate, a regional emission rate, or a calculated marginal rate. If those rates were higher in any states, zero-emitting MWhs would create more mass-denominated credits in those states, and thus RE and demand-side EE would be more valuable.

The incentive to target the location of zero-emitting generation or energy savings between states based on variation in its emission reduction value has been minimized by the fact that states participating in rate-based interstate trading must adopt the same emission performance rates or rate-based state goals. It is further minimized, even outside of an interstate trading framework, by the nature of the accounting method finalized in this rule. As explained above regarding the general accounting approach and the trading framework, we are adjusting rates using calculated MWhs, not based upon an emission reduction approximation as commenters outlined above. Not only does the method allow emission reductions to be accounted for as they occur across the grid, but it means the ERCs being traded across states represent one MWh of zero-emitting generation in whatever state it originated, and its value is unaffected by any emission rate associated with its state of origin. Thus, the finalized accounting and trading methods minimize the relative incentives for generating zero-emitting ERCs in a particular state based upon the rates that apply to that state.

IX. Community and Environmental Justice Considerations

In this section we provide an overview of the actions that the agency is taking to help ensure that vulnerable communities are not disproportionately impacted by this rulemaking.[1012] As described in the Executive Summary, climate change is an environmental justice issue. Low-income communities and communities of color already overburdened with pollution are likely to be disproportionately affected by, and less resilient to, the impacts of climate change. This rulemaking will provide broad benefit to communities across the nation, as its purpose is to reduce GHGs, the most significant driver of climate change. While addressing climate change will provide broad benefits, it is particularly beneficial to low-income populations and some communities of color (in particular, populations defined jointly by ethnic/racial characteristics and geographic location) where people are most vulnerable to the impacts of climate change (a more robust discussion of the impacts of climate change on vulnerable communities is provided in the Executive Order 12898 section XII.J of this preamble). While climate change is a global phenomenon, the adverse effects of climate change can be very localized, as impacts such as storms, flooding, droughts, and the like are experienced in individual communities.

Vulnerable communities also often receive more than their fair share of conventional air pollution, with the attendant adverse health impacts. The changes in electricity generation that will result from this rule will further benefit communities by reducing existing air pollution that directly contributes to adverse localized health effects. These air quality improvements will be achieved through this rule because the electric generating units that emit the most GHGs also have the highest emissions of conventional pollutants, such as SO_2, NO_X, fine particles, and HAP. These pollutants are known to contribute to adverse health outcomes, including the development of heart or lung diseases, such as asthma and bronchitis, increased susceptibility to respiratory and cardiac symptoms, greater numbers of emergency room visits and hospital admissions, and premature deaths.[1013] The EPA expects that the reductions in utilization of higher-emitting units likely to occur during the implementation of state plans will produce significant reductions in emissions of conventional pollutants, particularly in those communities already overburdened by pollution, which are often low-income communities, communities of color, and indigenous communities. These reductions will have beneficial effects on air quality and public health both locally and regionally. Further, this rulemaking complements other actions already taken by the EPA to reduce conventional pollutant emissions and improve health outcomes for overburdened communities.

By reducing millions of tons of CO_2 emissions that are contributing to global GHG levels and providing strong leadership to encourage meaningful reductions by countries across the globe, this rule is a significant step to address health and economic impacts of climate change that will fall disproportionately on vulnerable communities. By reducing millions of tons of conventional air pollutants, the rule will lead to better air quality and improved health in those communities. We heard from many commenters who recognize and welcome those benefits.

There are other ways in which the actions that result from this rulemaking may affect communities in positive or potentially adverse ways and we also heard about these from commenters.

While the agency expects overall emission decreases as a result of this

[1012] In this preamble, the EPA discusses environmental justice in two sections. Section XI.J specifically addresses how the agency has met the directives under Executive Order 12898. The EPA defines environmental justice as the fair treatment and meaningful involvement of all people regardless of race, color, national origin or income with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies. This section of the preamble addresses actions that the agency is taking related to environmental justice and other issues (*e.g.,* increased electricity costs) that may affect communities covered by Executive Order 12898 as well as other communities.

[1013] Six Common Air Pollutants. *http://www.epa.gov/oaqps001/urbanair/.*

rulemaking, we recognize that some EGUs may operate more frequently, as a result of this rulemaking. To the extent that we project increases in utilization as a result of this rulemaking, we expect these increases to occur generally in lower-emitting NGCC units, which have minimal or no emissions of SO_2 and HAP, lower emissions of particulate matter, and much lower emissions of NO_X compared to higher-emitting steam units. We acknowledge the concerns that have been raised on this point but also the difficulty in anticipating prior to plan implementation where those impacts might occur. In addition to providing for a robust state planning process with opportunity for meaningful input, the EPA is encouraging states to evaluate the actual impacts of their plans once implemented and, as described below, the EPA intends to conduct an assessment of whether and where emission increases may that may result from plan implementation and to work with states to mitigate adverse impacts, if any, in overburdened communities.

In addition to the many positive anticipated health benefits of this rulemaking, it also will increase the use of clean energy and will encourage EE. These changes in the electricity generation system, which are already occurring but may be accelerated by this program, are expected to have other positive benefits for communities. The electricity sector is, and will continue to be, investing more in RE and EE. The construction of renewable generation and the implementation of EE programs such as residential weatherization will bring investment and employment opportunities to the communities where they take place. We recognize that certain communities whose economies may be affected by changes in the utility and related sectors may be particularly impacted by the final rule. The EPA encourages states to make an effort to engage with these communities, including workers and their representatives in these sectors, including EE. It is important to ensure that all communities share in the benefits of this program. And while we estimate that its benefits will greatly exceed its costs (as noted in the RIA for this rulemaking), it is also important to ensure that to the extent there are increases in electricity costs, that those do not fall disproportionately on those least able to afford them.

The EPA has engaged with community groups throughout this rulemaking, and we received many comments on the issues outlined above from community groups, environmental justice organizations, faith-based organizations, public health organizations, and others.[1014] This input has informed this final rulemaking and prompted the EPA to consider other steps that the agency can take in the short and long term to assist states and stakeholders to consider environmental justice and impacts to communities in plan development and implementation.

It has also prompted us to work with our federal partners to make sure that states and communities have information on federal resources available to assist communities. We describe these resources below, as well as resources that the EPA will be providing to assist communities in accessing EE/RE and financial assistance programs. In our discussion below we also provide models of programs that other states are currently using to assist communities in accessing available resources that states could use when developing their plans.

Finally, and importantly, we recognize that communities must be able to participate meaningfully in state plan development. In this section, we discuss the requirements in the final rule for states, as they develop their plans, to provide opportunities for public involvement, and resources available to states and communities to enhance the success of the public process.

A. Proximity Analysis

The EPA is committed to assisting states and communities to develop plans that ensure there are no disproportionate, adverse impacts on overburdened communities. To provide information fundamental to beginning that process, the EPA has conducted a proximity analysis for this final rulemaking that summarizes demographic data on the communities located near power plants.[1015] The EPA understands that, in order to prevent disproportionately, high and adverse human health or environmental effects on these communities, both states and communities must have information on the communities living near facilities, including demographic data, and that accessing and using census data files requires expertise that some community groups may lack. Therefore, the EPA used census data from the American Community Survey (ACS) 2008–2012 to conduct a proximity analysis that can be used by states and communities as they develop state plans and as they later assess the final plans' impacts. The analysis and its results are presented in the EJ Screening Report for the Clean Power Plan, which is located in the docket for this rulemaking at EPA–HQ–OAR–2013–0602.

The proximity analysis provides detailed demographic information on the communities located within a 3-mile radius of each affected power plant in the U.S. Included in the analysis is the breakdown by percentage of community characteristics such as income and minority status. The analysis shows a higher percentage of communities of color and low-income communities living near power plants than national averages. It is important to note that the impacts of power plant emissions are not limited to a 3-mile radius and the impacts of both potential increases and decreases in power plant emissions can be felt many miles away. Still, being aware of the characteristics of communities closest to power plants is a starting point in understanding how changes in the plant's air emissions may affect the air quality experienced by some of those already experiencing environmental burdens.

Although overall there is a higher fraction of communities of color and low-income populations living near power plants than national averages, there are differences between rural and urban power plants. There are many rural power plants that are located near small communities with high percentages of low-income populations and lower percentages of communities of color. In urban areas, nearby communities tend to be both low-income communities and communities of color. In light of this difference between rural and urban communities proximate to power plants and in order to adequately capture both the low-income and minority aspects central to environmental justice considerations, we use the terms ''vulnerable'' or ''overburdened'' when referring to these communities. Our intent is for these terms to be understood in an expansive sense, in order to capture the full scope of communities, including indigenous communities most often located in rural areas, that are central to our environmental justice and community considerations.

As stated in the Executive Order 12898 discussion located in section XII.J of this preamble, the EPA believes that all communities will benefit from this final rulemaking because this action directly addresses the impacts of climate change by limiting GHG emissions through the establishment of CO2 emission guidelines for existing affected fossil fuel-fired power plants.

[1014] Detailed information on the outreach conducted as part of this rulemaking is provided in section I of this preamble.

[1015] The proximity analysis was conducted using the EPA's environmental justice mapping and screening tool, EJSCREEN.

The EPA also believes that the information provided in the proximity analysis will promote engagement between vulnerable communities and their states and will be useful for states as they begin developing their plans. In addition to providing the proximity analysis in the docket of this rulemaking, the EPA will disseminate the proximity analysis to states and will make it publicly available on its Clean Power Plan (CPP) Community Portal. Furthermore, the EPA has also created an interactive mapping tool that illustrates where power plants are located and provides information on a state level. This tool is available at: *http://cleanpowerplanmaps.epa.gov/CleanPowerPlan/*.

Additionally, the EPA encourages states to conduct their own analyses of community considerations when developing their plans. Each state is uniquely knowledgeable about its own communities and well-positioned to consider the possible impacts of plans on vulnerable communities within its state. Conducting state-specific analyses would not only help states assess possible impacts of plan options, but it would also enhance a state's understanding of the means to engage these communities that would most effectively reach them and lead to valuable exchanges of information and concerns. A state analysis, together with the proximity analysis conducted by the EPA, would provide a solid foundation for engagement between a state and its communities.

Such state-specific analyses need not be exhaustive. An examination of the options a state is considering for its plan, and any projections of likely resulting increases in power plant emissions affecting low-income populations, communities of color populations, or indigenous communities, would be informative for communities. The analyses could include available air quality monitoring data and information from air quality models, and, if available, take into account information about local health vulnerabilities such as asthma rates or access to healthcare. Alternatively, a simple analysis may consider expected EGU utilization in geographic proximity to overburdened communities. The EPA will provide states with information on its publicly available environmental justice screening and mapping tool, EJ SCREEN, which they may use in conducting a state-specific analysis. The EPA will also provide states with resources containing examples of analyses that other states have conducted to examine the impacts of their programs on overburdened communities. Additionally, the EPA encourages states to submit a copy of their analysis if they choose to conduct one, with their initial and final plan submittals.

B. Community Engagement in State Plan Development

In sections VIII.D–E of this preamble, the EPA explains that states need to engage meaningfully with communities and other stakeholders during the initial and final plan submittal processes. Meaningful engagement includes outreach to vulnerable communities, sharing information and soliciting input on state plan development and on any accompanying assessments such as those described above, and selecting methods for engagement to support communities' involvement at critical junctures in plan formulation and implementation. This engagement also includes providing the public the opportunity to comment on the state's initial submittal and responding to significant comments received, including comments from vulnerable communities, as well as conducting a public hearing and responding to comments before a final state plan is submitted. Additionally, the EPA expects that states will conduct outreach meetings, which could include public hearings or listening sessions, before the initial submittal is made. The EPA also encourages states to provide background information about their proposed final state plan or their initial state plan in the appropriate languages in advance of their public hearing and at their public hearing. The EPA recommends that states provide translators and other resources at their public hearings, to ensure that members of the public can provide oral feedback.

In the initial submittal, the final rule requires that states provide information to the agency about the community engagement they have undertaken and the means by which they intend to involve vulnerable communities and other stakeholders as they develop their final plan. Furthermore, as noted in section VIII.E of this preamble, in determining if states are eligible for a 2-year extension for submission of final plans, the rule requires that states demonstrate how they are meaningfully engaging vulnerable communities and other interested stakeholders as part of their public participation process. The EPA consulted its May 2015, *Guidance on Considering Environmental Justice During the Development of Regulatory Actions,* when crafting this rulemaking and recommends that states consult it to assist them in engaging meaningfully with vulnerable communities.[1016] Additionally, states in their initial submittal and 2017 update must show how they identified the communities with whom they are engaging as they develop their plans. Some suggested actions that states could take to engage actively with the public, including conducting meaningful engagement with vulnerable communities, are outlined in section VIII.E of this preamble. Additionally, as outlined in section VIII.D, the final plan submitted by states must include an overview of the public hearing(s) conducted and information on how the state ensured that the hearing(s) were accessible to stakeholders including vulnerable communities.

The EPA is committed to supporting states in effectively engaging with communities as they develop and implement their plans. The EPA will provide training and other resources throughout the implementation process that will assist states and communities in understanding plan requirements and options for plan development. These trainings will be a continuation of those that the EPA has already conducted with communities and states both pre- and post-proposal. The EPA will reach out to a wide variety of community stakeholders, including groups representing environmental justice communities, faith-based organizations, academic organizations working with vulnerable and overburdened communities, affordable housing advocates, public health professionals, public health organizations, and other community stakeholders.

C. Providing Communities With Access to Additional Resources

In addition to providing resources to states, the EPA encourages states to be aware of existing efforts undertaken by other states aimed at providing low-income communities access to financial and technical assistance programs for EE and RE, and to consider similar approaches that may make sense for their own states. The EPA encourages states to consider targeting economic development resources to communities that are likely to be negatively affected by ongoing changes in the utility and related sectors in support of efforts to diversify their economies, attract new sources of investment, and create new jobs.

One example of a program targeted at low-income communities is the

[1016] Guidance on Considering Environmental Justice During the Development of Regulatory Actions. *http://epa.gov/environmentaljustice/resources/policy/considering-ej-in-rulemaking-guide-final.pdf*. May 2015.

Maryland EmPOWER Low Income Energy Efficiency Program (LIEEP).[1017] The LIEEP program administered by the Maryland Department of Housing and Community Development (DHCD) helps low-income households through free installation of energy conservation materials (*i.e.,* installation, hot water system improvements, lighting retrofits, furnace cleaning, tuning and safety repairs, refrigerator retrofits, etc.).[1018] Funding for this program is provided by EmPOWER Maryland partners: Baltimore Gas and Electric, Southern Maryland Electric Cooperative, Delmarva Power, Allegheny Energy and Pepco.[1019] This program is available to both homeowners and renters.[1020] Additionally, the Maryland Department of Housing provides low-income families with home heating bill assistance and furnace repairs and replacements through the Maryland Energy Assistance Program (MEAP).[1021] Maryland's Electric Universal Service Program (EUSP) helps low-income electric customers with their electric bills.[1022]

Another example of a program is EmPower New York, which provides no-cost energy solutions to low-income populations.[1023] Currently there are about 100,000 people who are receiving assistance. Both homeowners and renters are eligible to receive assistance under this program. The types of assistance available include EE upgrades (plugging leaks, adding insulation, replacing inefficient refrigerators and freezers and new energy-efficient lighting). Other states, like the State of Colorado's Energy Outreach Colorado program, offer similar resources for low-income populations.[1024]

In 2013, the New York State Energy and Research Development Authority (NYSERDA) was able to secure a triple-A rated financial guarantee from the state's Clean Water State Revolving Fund (SRF) for a $24 million bond issue. Proceeds funded residential EE loans that were available to all utility customers, including low-income households. SRF eligibility was based on the beneficial impact of EE investment in reducing atmospheric deposition on impaired water bodies consistent with Section 319 of the Clean Water Act.

As discussed below, there are also many federal programs that can help low-income populations access the benefits of RE, EE, and the economic benefits of a cleaner energy economy.

In the coming months, the EPA will continue to provide information and resources for communities and states on existing federal, state, local, and other financial assistance programs to encourage EE/RE opportunities that are already available to communities. For example the EPA will provide a catalog of current or recent state and local programs that have successfully helped communities adopt EE/RE measures. The goal of these resources is to help vulnerable communities gain the benefits of this rulemaking by encouraging that states use these types of tools in their state plans. The use of these RE/EE tools can also help low-income households reduce their electricity consumption and bills.

The EPA recognizes the potential impacts that this rulemaking could have on jobs in communities. Therefore, in section VIII.G of this preamble, the EPA has outlined that states, in designing their state plans, should consider the effects of their plans on employment and overall economic development to realize the opportunities for economic growth and jobs that the plans offer. To the extent possible, states should try to assure that communities that may be expected to experience job losses can also take advantage of the opportunities for job growth or otherwise transition to healthy, sustainable economic growth (*e.g.,* with regard to delivering EE measures and installing rooftop solar panels). Additionally, as part of the resources that we will be providing to states and low-income communities, the EPA will provide information on the Administration's Partnerships for Opportunity and Workforce and Economic Revitalization (POWER) Initiative and other programs that specifically target economic development assistance to communities affected by changes in the coal industry and the utility power sector.[1025]

D. Federal Programs and Resources Available to Communities

Federal agencies have a history of bringing EE and RE to low-income communities. Earlier this summer, the Administration announced a new initiative to scale up access to solar energy and cut energy bills for all Americans, in particular low- and moderate-income communities, and to create a more inclusive solar workforce. As part of this new initiative, the U.S. Department of Energy (DOE), the U.S. Department of Housing and Urban Development (HUD), U.S. Department of Agriculture (USDA), and the EPA launched a National Community Solar Partnership to unlock access to solar energy for the nearly 50 percent of households and businesses that are renters or do not have adequate roof space to install solar systems, with a focus on low- and moderate-income communities. The Administration also set a goal to install 300 megawatts (MW) of RE in federally subsidized housing by 2020 and plants to provide technical assistance to make it easier to install solar energy on affordable housing, including clarifying how to use federal funding for EE and RE. To continue enhancing employment opportunities in the solar industry for all Americans, AmeriCorps is providing funding to deploy solar energy and create jobs in underserved communities, and DOE is working to expand solar energy education and opportunities for job training.

These recent announcements build on the many existing federal programs and resources available to improve EE and accelerate the deployment of RE in vulnerable communities. Some examples of these resources include: the Department of Energy's Weatherization Assistance Program, Health and Human Service's Low Income Home Energy Assistance Program, the Department of Agriculture's Energy Efficiency and Conservation Loan Program, High Cost Energy Grant Program, and the Rural Housing Service's Multi-Family Housing Program.

HUD supports EE improvements and the deployment of RE on affordable housing through its Energy Efficient Mortgage Program, Multifamily Property Assessed Clean Energy Pilot with the State of California, PowerSaver Program, and the use of Section 108 Community Development Block Grants. The Department of Treasury provides several tax credits to support RE development and EE in low-income communities, including the New Markets Tax Credit Program and the Low-Income Housing Tax Credit. The EPA's RE-Powering America's Land Initiative promotes the reuse of potentially contaminated lands, landfills and mine sites—many of which are in low-income communities—for RE through a combination of tailored redevelopment tools for communities and developers, as well as site-specific technical support. The EPA's Green

[1017] EmPOWER Maryland Low Income Energy Efficiency Programs (LIEEP). *http://www.mdhousing.org/Website/Programs/lieep/Default.aspx.*

[1018] Ibid.

[1019] Ibid.

[1020] Ibid.

[1021] Energy Assistance. *http://www.dhr.state.md.us/blog/?page_id=4326.*

[1022] Ibid.

[1023] EmPower New York. *http://www.nyserda.ny.gov/All-Programs/Programs/EmPower-New-York.*

[1024] Energy Outreach Colorado. *http://www.energyoutreach.org/about.*

[1025] *http://www.eda.gov/power.*

Power Partnership is increasing community use of renewable electricity across the country and in low-income communities. The EPA partners with EE programs throughout the country that leverage ENERGY STAR to deliver broad consumer energy-saving benefits, of particular value to low-income households who can least afford high energy bills. ENERGY STAR also works with houses of worship to reduce energy costs—savings that can then be repurposed to their community mission, including programs and assistance to residents in low-income communities. The EPA will be working with these federal partners and others to ensure that states and vulnerable communities have access to information on these programs and their resources.

The federal government also has a number of programs to expand employment opportunities in the energy sector, including for underserved populations. Examples of these include HUD, DOE, and the Department of Education's ''STEM, Energy, and Economic Development'' program; DOE's Diversity in Science and Technology Advances National Clean Energy in Solar (DISTANCE-Solar) Program; Grid Engineering for Accelerated Renewable Energy Deployment (GEARED); the Department of Labor's Trade Adjustment Assistance Community College and Career Training (TAACCCT), Apprenticeship USA Advancing Apprenticeships in the Energy Field, Job Corps Green Training and Greening of Centers, and YouthBuild; and the EPA's Environmental Workforce Development and Job Training (EWDJT) program.

E. Multi-Pollutant Planning and Co-Pollutants

As outlined in the final Clean Power Plan, states and sources have continued obligations to meet all other CAA requirements addressing conventional pollutants. Because the CAA envisions control of these other pollutants as a continuous process (through provisions such as periodic review of the NAAQS and residual risk requirements under the MACT program), the EPA believes that the Clean Power Plan provides an opportunity for states to consider strategies for meeting future CAA planning obligations as they develop their plans under this rulemaking. Multi-pollutant strategies that incorporate criteria pollutant reductions over the planning horizons specific to particular states, jointly with strategies for reducing CO_2 emissions from affected EGUs needed to meet Clean Power Plan requirements over the time horizon of this rule, may accomplish greater environmental results with lower long-term costs. Such strategies may also provide opportunities for states, communities, and affected facilities to consider the most effective means of meeting these obligations while limiting or eliminating localized emission increases that would otherwise affect overburdened communities. Furthermore, this type of multi-pollutant approach has been suggested by states and regulated sources in past rulemakings as a tool to determine the best system of emission reductions. The EPA recommends that states consider such strategies in consultation with their communities, affected facilities, and other stakeholders.

Air quality in a given area is affected by emissions from nearby sources and may be influenced by emissions that travel hundreds of miles and mix with emissions from other sources.[1026] In the Cross-State Air Pollution Rule the EPA used its authority to reduce emissions that significantly contribute to downwind exposures. The RIA for the final Cross-State Air Pollution Rule anticipates substantial health benefits for the population across a wide region. Similarly, the EPA believes that, like the Cross-State Air Pollution Rule, this rulemaking will result in significant health benefits because it will reduce co-pollutant emissions of SO_2 and NO_X on a regional and national basis.[1027] Thus, localized increases in NO_X emissions may well be more than offset by NO_X decreases elsewhere in the region that produce a net improvement in ozone and particulate concentrations across the area.

Another effect of the final CO_2 emission guidelines for affected existing fossil fuel-fired EGUs may be increased utilization of other, unmodified EGUs—in particular, high efficiency gas-fired EGUs—with relatively low GHG emissions per unit of electrical output. These plants may operate more hours during the year and could emit pollutants, including pollutants whose environmental effects would be localized and regional rather than global as is the case with GHG emissions. Changes in utilization already occur in response to energy demands and evolving energy sources, but the final CO_2 emission guidelines for affected existing fossil fuel-fired EGUs can be expected to cause more such changes. Increased utilization of solid fossil fuel-fired units generally would not increase peak concentrations of $PM_{2.5}$, NO_X, or ozone around such EGUs to levels higher than those that are already occurring because peak hourly or daily emissions generally would not change; however, increased utilization may make periods of relatively high concentrations more frequent. It should be noted that the gas-fired sources likely to be dispatched more frequently have very low emissions of primary PM, SO_2, and HAP per unit of electrical output and that they must continue to comply with other CAA requirements that directly address the conventional pollutants, including federal emission standards, rules included in SIPs, and conditions in Title V operating permits, in addition to the guidelines in this final rulemaking. Therefore, local (or regional) air quality for these pollutants is not likely to be significantly affected.

For natural gas-fired EGUs, the EPA found that regulation of HAP emissions ''is not appropriate or necessary because the impacts due to HAP emissions from such units are negligible based on the results of the study documented in the utility RTC.'' [1028] Because gas-fired EGUs emit essentially no mercury, increased utilization will not increase methyl mercury concentrations in water bodies near these affected EGUs. In studies done by DOE/NETL comparing cost and performance of coal- and NGCC-fired generation, they assumed SO_2, NO_X, PM (and Hg) emissions to be ''negligible.'' Their studies predict NO_X emissions from a NGCC unit to be approximately 10 times lower than a subcritical or supercritical coal-fired boiler.[1029] Many, although not all, NGCC units are also very well controlled for emissions of NO_X through the application of after combustion controls such as selective catalytic reduction.

F. Assessing Impacts of State Plan Implementation

It is important to the EPA that the implementation of state plans be assessed in order to identify whether they cause any adverse impacts on communities already overburdened by disproportionate environmental harms and risks. The EPA will conduct its own assessment during the implementation phase of this rulemaking to determine whether the implementation of state plans developed pursuant to this rulemaking and other air quality rules are, in fact, reducing emissions and improving air quality in all areas or whether there are localized air quality impacts that need to be addressed under other CAA authorities. Furthermore, the

[1026] 76 FR 48348.

[1027] 76 FR 48347.

[1028] 65 FR 79831.

[1029] ''Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity'' Rev 2a, September 2013 Revision 2, November 2010 DOE/NETL–2010/1397.

EPA recommends that states conduct evaluations of their own to determine the impacts of their plans on overburdened communities. An example of one such approach to assessing a state plan for reducing GHGs is the California Air Resources Board's (CARB), *First Update on the Climate Change Scoping Plan: Building on the Framework Pursuant to AB32: The California Global Warming Solutions Act of 2006,* which outlines ongoing evaluations that it will conduct to determine the impacts of its programs (throughout the implementation stages) on overburdened communities.[1030] CARB's Adaptive Management Plan for the Cap-and-Trade Program is one particular evaluation, which is intended to assess any localized emissions increases resulting from the program so that the state can appropriately respond.[1031] The EPA recommends that states consider CARB's approaches and other programs as models for conducting ongoing assessments of the impacts of their state plans on overburdened communities. The EPA will provide training for states and communities on resources that they can use to assess options for plan development and implementation that appropriately consider localized impacts, especially effects of co-pollutants, as well as training on how to develop and carry out these evaluations.

This training will include guidance in accessing the publicly available information that sources and states currently report that can help with ongoing assessments of state plan impacts. For example, unit-specific emissions data and air quality monitoring data are readily available. This information, together with the assessment that the EPA will conduct in the implementation phase of this rulemaking and other analyses that states may develop, will enable states and communities to monitor any disproportionate emissions that may result in adverse impacts and to address them.

G. EPA Continued Engagement

The EPA is committed to helping ensure that this action will not have disproportionate adverse human health or environmental effects on vulnerable communities. Throughout the implementation phase of this rulemaking, the agency will continue to provide trainings and resources to assist communities and states as they engage with one another. Additionally, we will provide states with recommendations on best practices for engaging with vulnerable communities. The EPA, through its outreach efforts during implementation, will continue to solicit feedback from communities and states on topics for which they would like additional trainings and resources.

The EPA will also provide states with resources containing examples of analyses that other states have conducted to examine the impacts of their programs on vulnerable communities, as well as information on its publicly available environmental justice screening and mapping tool, EJ SCREEN. States are encouraged to use this preliminary information as well as other available information to conduct their own analyses. As described above, the EPA will assess the impacts of this rulemaking during its implementation. The EPA will house this assessment, along with the proximity analysis and other information generated throughout the implementation process, on its Clean Power Plan (CPP) Community Portal that will be linked to this rulemaking's Web site (*www.epa.gov/cleanpowerplan*). In addition, the EPA has expanded its set of resources that are being developed to help states and communities understand the breadth of policy options and programs that have successfully brought EE/RE to overburdened communities. The EPA is committed to continuing its engagement with states and communities from the beginning of plan development through plan implementation.

A more detailed discussion concerning the application of Executive Order 12898 in this rulemaking can be found in section XI.J of this preamble. A summary of the EPA's interactions with communities is in the EJ Screening Report for the Clean Power Plan, available in the docket of this rulemaking. Furthermore, the EPA's responses to public comments, including comments received from communities, are provided in the response to comments documents located in the docket for this rulemaking.

In summary, the EPA in this final rulemaking has designed an integrative approach that helps to ensure that vulnerable communities are not disproportionately impacted by this rulemaking. The proximity analysis that the agency has conducted for this rulemaking is a central component of this approach. Not only is the proximity analysis a useful tool to help identify overburdened communities that may be impacted by this rulemaking, states can use this tool as they engage with communities in the development of their plans, consider a multi-pollutant approach, help low-income communities access EE/RE and financial assistance programs and assess the impacts of their state plans. Additionally, in order to continue to ensure that vulnerable communities are not disproportionately impacted by this rulemaking, the EPA will also be conducting its own assessment during the implementation phase. Furthermore, the EPA will continue to engage with communities and states throughout the implementation phase of this rulemaking to help ensure that vulnerable communities are not disproportionately impacted.

X. Interactions With Other EPA Programs and Rules

A. Implications for the New Source Review Program

The new source review (NSR) program is a preconstruction permitting program that requires major stationary sources of air pollution to obtain permits prior to beginning construction. The requirements of the NSR program apply both to new construction and to modifications of existing major sources. Generally, a source triggers these permitting requirements as a result of a modification when it undertakes a physical or operational change that results in a significant emission increase and a net emissions increase. NSR regulations define what constitutes a significant net emissions increase, and the concept is pollutant-specific. As a result of the decision in *Utility Air Regulatory Group (UARG)* v. *Environmental Protection Agency (EPA),* 134 S. Ct. 2427 (2014), a modification that increases only GHG emissions above the applicable level will not trigger the requirement to obtain a PSD permit. Under existing EPA regulations, a modifying major stationary source would trigger PSD permitting requirements for GHGs if it undergoes a change or change in the method of operation (modification) that results in a significant increase in the emissions of a pollutant other than GHGs and results in a GHG emissions increase of 75,000 tons per year CO_2e as well as a GHG emissions increase on a mass basis. Once it has been determined that a change triggers the requirements of the NSR program, the source must obtain a permit prior to making the change. The pollutant(s) at issue and the air quality designation of the area where the

[1030] *First Update on the Climate Change Scoping Plan: Building on the Framework Pursuant to AB32: The California Global Warming Solutions Act of 2006. http://www.arb.ca.gov/cc/scopingplan/2013_update/first_update_climate_change_scoping_plan.pdf.* May 2014.

[1031] *Adaptive Management Plan for the Cap-and-Trade Regulation. http://www.arb.ca.gov/cc/capandtrade/adaptive_management/plan.pdf.* October 2011.

facility is located or proposed to be built determine the specific permitting requirements.

As part of its CAA section 111(d) plan, a state may impose requirements that require an affected EGU to undertake a physical or operational change to improve the unit's efficiency that results in an increase in the unit's dispatch and an increase in the unit's annual emissions. If the emissions increase associated with the unit's changes exceeds the thresholds in the NSR regulations for one or more regulated NSR pollutants, including the netting analysis, the changes would trigger NSR.

While there may be instances in which an NSR permit would be required, we expect those situations to be few. As previously discussed in this preamble, states have considerable flexibility in selecting varied measures as they develop their plans to meet the goals of the emission guidelines. One of these flexibilities is the ability of the state to establish emission standards in their CAA section 111(d) plans in such a way so that their affected sources, in complying with those standards, in fact would not have emissions increases that trigger NSR. To achieve this, the state would need to conduct an analysis consistent with the NSR regulatory requirements that supports its determination that as long as affected sources comply with the emission standards in their CAA section 111(d) plan, the source's emissions would not increase in a way that trigger NSR requirements.

For example, a state could decide to use demand-side measures or increase reliance on RE as a way of reducing the future emissions of an affected source initially predicted (without such alterations) to increase its emissions as a result of a CAA section 111(d) plan requirement. In other words, a state plan's incorporation of expanded use of cleaner generation or demand-side measures could yield the result that units that would otherwise be projected to trigger NSR through a physical change that might result in increased dispatch would not, in fact, increase their emissions, due to reduced demand for their operation. The state could also, as part of its CAA section 111(d) plan, develop conditions for a source expected to trigger NSR that would limit the unit's ability to move up in the dispatch enough to result in a significant net emissions increase that would trigger NSR (effectively establishing a synthetic minor limit).[1032]

In addition, in this final rule, we have also adjusted the date of the period for mandatory reductions to 2022, instead of 2020, and provided states with flexibility with respect to the glide path. This obviates concerns that there is insufficient time for sources that may need permits to obtain them and allows additional planning time for these changes to be undertaken in a manner that does not trigger PSD. As a result of such flexibility and anticipated state involvement, we expect that a limited number of affected sources would trigger NSR when states implement their plans.

B. Implications for the Title V Program

In the preamble to the June 18, 2014 proposal, the EPA discussed the issue of excessive title V fees resulting inadvertently as a consequence of the promulgation of the first section 111 standard to regulate GHGs. Specifically, the EPA explained that when the first section 111 standard is promulgated for GHGs, if we do not revise 40 CFR parts 70 and 71 (the operating permit rule), then certain permitting authorities would be required to charge emissions-based fees for GHGs, resulting in fees that would be far in excess of what is required to cover the reasonable costs of the permitting programs. To avoid this situation, the EPA proposed as part of the re-proposed carbon pollution standards for newly constructed fossil fuel-fired power plants (70 FR 1429–1519; January 8, 2014) to exempt GHGs from the list of air pollutants that are subject to fee calculation requirements under the operating permit rules. Also, we proposed several options to impose a smaller fee adjustment for GHGs that would be reasonable and designed to recover the costs of addressing GHGs in permitting without being excessive.

In a separate action in this issue of the **Federal Register**, the EPA is finalizing changes to the operating permits rules to address the title V fee issue. In particular, we are taking final action to exempt GHGs from emissions-based fee calculation requirements under the operating permit rules. In addition, we are also finalizing a modest GHG fee adjustment to recover the costs of addressing GHGs in permitting. The GHG adjustments we are finalizing are based on accounting for the number of permit actions that require a GHG assessment in a given period, rather than accounting for emissions levels of GHGs. Finally, the EPA is also finalizing the addition of text within 40 CFR part 60, subpart TTTT, to clarify that the fee pollutant for operating permit purposes is GHG (as defined in 40 CFR 70.2 and 71.2) to add clarity to our regulations and to avoid the potential need for possible future rulemakings to adjust the title V fee regulations if any constituent of GHG, other than CO_2, becomes subject to regulation under CAA section 111 for the first time.

This title V fee issue is a one-time occurrence resulting from the promulgation of the first CAA section 111 standard to regulate GHGs (the standards of performance for new, modified, and reconstructed EGUs, also promulgated in this issue of the **Federal Register**). The title V fee issue is not an issue for any other subsequent CAA section 111 regulations, such as this section 111(d) standard; thus, there is no need to address any title V fee issues in this final rule as part of this action.

In the proposal, the EPA discussed that the section 111 rules would have no effect on the applicability thresholds for GHG under the operating permit rules. After the proposal for this rulemaking was published, the U.S. Supreme Court issued its opinion in *UARG* v. *EPA,* 134 S.Ct. 2427 (June 23, 2014), and in accordance with that decision, the D.C. Circuit subsequently issued an amended judgment in *Coalition for Responsible Regulation, Inc.* v. *Environmental Protection Agency,* Nos. 09–1322, 10–073, 10–1092 and 10–1167 (D.C. Cir., April 10, 2015). Those decisions support the same overall conclusion, as the EPA discussed in the proposal, with respect to the effect of this final section 111 rule on the applicability thresholds for GHGs under the operating permits rules, though for different reasons.

With respect to title V, the Supreme Court said that EPA may not treat GHGs as an air pollutant for purposes of determining whether a source is a major source required to obtain a title V operating permit. In accordance with that decision, the D.C. Circuit's amended judgment vacated the title V regulations under review in that case to the extent that they require a stationary source to obtain a title V permit solely because the source emits or has the potential to emit GHGs above the applicable major source thresholds. The D.C. Circuit also directed the EPA to consider whether any further revisions to its regulations are appropriate in light of *UARG* v. *EPA,* and, if so, to undertake to make such revisions. These court

[1032] Certain stationary sources that emit or have the potential to emit a pollutant at a level that is equal to or greater than specified thresholds are subject to major source requirements. *See, e.g.,* CAA sections 165(a)(1), 169(1), 501(2), 502(a). A synthetic minor limitation is a legally and practicably enforceable restriction that has the effect of limiting emissions below the relevant level and that a source voluntarily obtains to avoid major stationary source requirements, such as the PSD or Title V permitting programs. *See, e.g.,* 40 CFR 52.21(b)(4), 51.166(b)(4), 70.2 (definition of ''potential to emit'').

decisions make clear that promulgation of CAA section 111 requirements for GHGs will not result in EPA imposing a requirement that stationary sources obtain a title V permit solely because such sources emit or have the potential to emit GHGs above the applicable major source thresholds.

C. Interactions With Other EPA Rules

Fossil fuel-fired EGUs are, or potentially will be, impacted by several other recently finalized or proposed EPA rules.[1033] The EPA recognizes the importance of assuring that each of the rules described below can achieve its intended environmental objectives in a commonsense, cost-effective manner, consistent with underlying statutory requirements, and while assuring a reliable power system. Executive Order 13563, ''Improving Regulation and Regulatory Review,'' issued on January 18, 2011, states that ''[i]n developing regulatory actions and identifying appropriate approaches, each agency shall attempt to promote . . . coordination, simplification, and harmonization. Each agency shall also seek to identify, as appropriate, means to achieve regulatory goals that are designed to promote innovation.'' Within the EPA, we are paying careful attention to the interrelatedness and potential impacts on the industry, reliability and cost that these various rulemakings can have.

1. Mercury and Air Toxics Standards (MATS)

On February 16, 2012, the EPA issued the MATS rule (77 FR 9304) to reduce emissions of toxic air pollutants from new and existing coal- and oil-fired EGUs. The MATS rule will reduce emissions of heavy metals, including mercury, arsenic, chromium, and nickel; and acid gases, including hydrochloric acid and hydrofluoric acid. These toxic air pollutants, also known as hazardous air pollutants or air toxics, are known to cause, or suspected of causing, damage nervous system damage, cancer, and other serious health effects. The MATS rule will also reduce SO_2 and fine particle pollution, which will reduce particle concentrations in the air and prevent thousands of premature deaths and tens of thousands of heart attacks, bronchitis cases and asthma episodes.

New or reconstructed EGUs (*i.e.,* sources that commence construction or reconstruction after May 3, 2011) subject to the MATS rule are required to comply by April 16, 2012 or upon startup, whichever is later.

Existing sources subject to the MATS rule were required to begin meeting the rule's requirements on April 16, 2015. Controls that will achieve the MATS performance standards are being installed on many units. Certain units, especially those that operate infrequently, may be considered not worth investing in given today's electricity market, and are closing. The final MATS rule provided a foundation on which states and other permitting authorities could rely in granting an additional, fourth year for compliance provided for by the CAA. States report that these fourth year extensions are being granted. In addition, the EPA issued an enforcement policy that provides a clear pathway for reliability-critical units to receive an administrative order that includes a compliance schedule of up to an additional year, if it is needed to ensure electricity reliability.

2. Cross-State Air Pollution Rule (CSAPR)

The CSAPR requires states to take action to improve air quality by reducing SO_2 and NO_X emissions that cross state lines. These pollutants react in the atmosphere to form fine particles and ground-level ozone and are transported long distances, making it difficult for other states to attain and maintain the NAAQS. The first phase of CSAPR became effective on January 1, 2015, for SO_2 and annual NO_X, and May 1, 2015, for ozone season NO_X. The second phase will become effective on January 1, 2017, for SO_2 and annual NO_X, and May 1, 2017, for ozone season NO_X. Many of the power plants participating in CSAPR have taken actions to reduce hazardous air pollutants for MATS compliance that will also reduce SO_2 and/or NO_X. In this way these two rules are complementary. Compliance with one helps facilities comply with the other.

3. Requirements for Cooling Water Intake Structures at Power Plants (316(b) Rule)

On May 19, 2014, the EPA issued a final rule under section 316(b) of the Clean Water Act (CWA) (33 U.S.C. 1326(b)) (referred to hereinafter as the 316(b) rule.) The rule was published on August 15, 2014 (79 FR 48300; August 15, 2014), and became effective October 14, 2014. The 316(b) rule establishes new standards to reduce injury and death of fish and other aquatic life caused by cooling water intake structures at existing power plants and manufacturing facilities.[1034] The 316(b) rule subjects existing power plants and manufacturing facilities that withdraw in excess of 2 million gallons per day) of cooling water, and use at least 25 percent of that water for cooling purposes, to a national standard designed to reduce the number of fish destroyed through impingement and a national standard for establishing entrainment reduction requirements. All facilities subject to the rule must submit information on their operations for use by the permit authority in determining 316(b) permit conditions. Certain plants that withdraw very large volumes of water will also be required to conduct additional studies for use by the permit authority in determining the site-specific entrainment reduction measures for such facilities. The rule provides significant flexibility for compliance with the impingement standards and, as a result, is not projected to impose a substantial cost burden on affected facilities. With respect to entrainment, the rule calls upon the permitting authority to establish appropriate entrainment reduction measures, taking into account, among other factors, remaining useful plant life and quantified and qualitative social benefits and cost. The permit writer may also consider impacts on the reliability of energy delivery within the facility's immediate area. Existing sources subject to the 316(b) rule are required to comply with the impingement requirements as soon as practicable after the entrainment requirements are determined. They must comply with applicable site-specific entrainment reduction controls based on the schedule of requirements established by the permitting authority.

4. Disposal of Coal Combustion Residuals From Electric Utilities (CCR Rule)

On December 19, 2014, the EPA issued the final rule for the disposal of coal combustion residuals from electric utilities. The rule provides a comprehensive set of requirements for the safe disposal of coal combustion residuals (CCRs), commonly known as coal ash, from coal-fired power plants. The CCR rule is the culmination of extensive study on the effects of coal ash on the environment and public health. The CCR rule establishes technical requirements for existing and

[1033] We discuss other rulemakings solely for background purposes. The effort to coordinate rulemakings is not a defense to a violation of the CAA. Sources cannot defer compliance with existing requirements because of other upcoming regulations.

[1034] CWA section 316(b) provides that standards applicable to point sources under sections 301 and 306 of the Act must require that the location, design, construction and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impacts.

new CCR landfills and surface impoundments under the Resource Conservation and Recovery Act, Subtitle D (42 U.S.C. 6941–6949a), the nation's primary law for regulating solid waste.

These regulations address the risks from coal ash disposal—leaking of contaminants into ground water, blowing of contaminants into the air as dust, and the catastrophic failure of coal ash surface impoundments by establishing requirements for where CCR landfills and surface impoundments may be located, how they must be designed, operated and monitored, when they must be inspected, and how they must be closed and cared for after closure. Additionally, the CCR rule sets out recordkeeping and reporting requirements, as well as the requirement for each facility to establish and post specific information to a publicly-accessible Web site. The final rule also supports the responsible recycling of CCRs by distinguishing safe, beneficial use from disposal.

5. Steam Electric Effluent Limitation Guidelines and Standards (SE ELG Rule)

The EPA is reviewing public comments and working to finalize the proposed SE ELG rule which will impact existing fossil fuel-fired EGUs. In 2013, the EPA proposed the SE ELG rule (78 FR 34432; June 7, 2013) to strengthen the controls on discharges from certain steam electric power plants by revising technology-based effluent limitations guidelines and standards for the steam electric power generating point source category. The current regulations, which were last updated in 1982, do not adequately address the toxic pollutants discharged from the electric power industry, nor have they kept pace with process changes that have occurred over the last three decades. Existing steam electric power plants currently contribute 50–60 percent of all toxic pollutants discharged to surface waters by all industrial categories regulated in the U.S. under the CWA. Furthermore, power plant discharges to surface waters are expected to increase as pollutants are increasingly captured by air pollution controls and transferred to wastewater discharges. The proposed regulation, which includes new requirements for both existing and new generating units, would reduce impacts to human health and the environment by reducing the amount of toxic metals and other pollutants currently discharged to surface waters from power plants. The EPA intends to take final action on the proposed rule by September 30, 2015.

The EPA is endeavoring to enable EGUs to comply with applicable obligations under other power sector rules as efficiently as possible (*e.g.,* by facilitating their ability to coordinate planning and investment decisions with respect to those rules) and, where possible, implement integrated compliance strategies. For example, in the proposed SE ELG rule, the EPA describes its thinking on how it might effectively harmonize the potential requirements of that rule with the requirements of the final CCR rule. Because these two rules affect similar units and may be met with similar compliance strategies, common-sense implementation timeframes were established in the CCR final rule so that utilities would not be required to make major decisions about CCR units without first understanding the implications that such decisions would have for meeting the surface water protection requirements of the final ELG rule. The EPA is taking into account these new CCR requirements for coal ash as it develops the final SE ELG rule. The EPA's goal in harmonizing the SE ELG and CCR rules is to minimize the overall complexity of the two regulatory structures and avoid creating unnecessary burden.

6. Other EPA Rules

In addition to the power sector rules discussed above, the development of SIPs for criteria pollutants (ozone, $PM_{2.5}$, and SO_2) and regional haze may also have implications for existing fossil-fired EGUs.

Regarding ozone, the proposal included a discussion of the June 6, 2013, proposed implementation rule for the 2008 ozone National Ambient Air Quality Standards (NAAQS), addressing the statutory requirements for areas EPA has designated as nonattainment for the 2008 ozone NAAQS. The final implementation rule for the 2008 ozone NAAQS was signed on February 13, 2015, and published on March 6, 2015, with an effective date of April 6, 2015. In general, the 2008 ozone NAAQS implementation rule interprets applicable statutory requirements and provides flexibility to states to minimize administrative burdens associated with developing and implementing plans to meet and maintain the NAAQS. The rule establishes due dates for attainment plans and clarifies attainment dates for each ozone nonattainment area according to its classification based on air quality thresholds, with attainment dates starting in July 2015 through July 2032 depending on an area's classification.

On November 25, 2014, the EPA Administrator signed the proposed rulemaking for the 2015 revisions to the ozone NAAQS. The proposal was published in the **Federal Register** on December 17, 2014 (79 FR 75234). The Administrator proposed to revise the primary ozone standard to a level in the range of 0.065 to 0.070 ppm and took comment on lower levels including 0.060 ppm and on retaining the current standard of 0.075 ppm. Among other things, the ozone NAAQS proposal also proposed to retain the current indicator, averaging time, and form of the standard and included a proposed secondary ozone NAAQS in the 0.065 to 0.070 ppm range.

The proposal also outlined the key implementation milestones requiring revised SIPs, with due dates starting in October 2018 for infrastructure and interstate transport SIPs, attainment plans due 2020–21, and attainment dates of 2020–37. The EPA is under a court order to finalize its review of the ozone NAAQS by October 1, 2015.

Some commenters expressed concern with the potential impact proposed revisions to the ozone NAAQS could have on state planning efforts and affected entities' ability to comply with any potentially new requirements associated with a revised ozone NAAQS and those related to the 111(d) emission guidelines. In particular, commenters raised issues with a potentially more stringent ozone standard and the permitting and state planning implications this may create. While there was no discussion of the proposed revisions to the ozone NAAQS in the 111(d) emission guidelines proposal, commenters expressed a desire for the EPA to coordinate promulgation of the final 111(d) emission guidelines (and any other climate regulations) with the potential revision to the ozone standard to provide certainty and flexibility for states and affected sources.

While it is premature to speculate about the outcome of the ozone NAAQS review and how a more stringent ozone NAAQS may impact sources of ozone precursor emissions, including EGUs, we believe the planning and compliance timeframes that would follow from a revised ozone NAAQS and the timeframes we are finalizing today for submittal of the CAA section 111(d) state plans will allow considerable time for coordination by states in the development of their respective plans, as needed. As stated in the proposal, the EPA is prepared to work with states to assist them in coordinating their efforts across these planning processes.

Regarding $PM_{2.5}$ NAAQS implementation, the proposal stated that the EPA was developing a proposed implementation rule to provide guidance to states on the development of SIPs for the 2012 $PM_{2.5}$ NAAQS. The proposed $PM_{2.5}$ SIP requirements rule was signed on March 10, 2015, and published on March 23, 2015 (80 FR 15340). The proposal addresses a number of requirements including attainment plan due dates, attainment dates and attainment date extension criteria for Moderate and Serious nonattainment areas; determination criteria for Reasonably Available Control Measures (RACM) for Moderate areas and Best Available Control Measures (BACM) for Serious areas; plans for demonstrating reasonable further progress and for meeting periodic quantitative milestones; and criteria for reclassifying a Moderate nonattainment area to Serious. The EPA is planning to finalize the $PM_{2.5}$ implementation rule in early 2016.

There are currently only 9 areas designated nonattainment for the 2012 $PM_{2.5}$ NAAQS, with an effective date of April 15, 2015. Since the attainment plans for these areas must be completed and submitted to the EPA in September 2016, we expect that the four states with such areas should have already decided on their approach to implementing the 2012 $PM_{2.5}$ NAAQS when they begin to develop their plans for implementing the 111(d) guidelines, and will be able to coordinate the two.

Related to the SO_2 NAAQS, and as stated in the proposal, the SO_2 NAAQS was revised in June 2010 to protect public health from the short-term effects of SO_2 exposure. In July 2013, the EPA designated 29 areas in 16 states as nonattainment for the SO_2 NAAQS. The EPA based these nonattainment designations on the most recent set of certified air quality monitoring data as well as an assessment of nearby emission sources and weather patterns that contribute to the monitored levels. The date for attainment plans for these areas to be completed and submitted to the EPA was April 2015. As such, we expect states with such areas to have already decided on their approach to implementing the SO_2 NAAQS as they start planning for implementation of the 111(d) guidelines, which should allow for coordination and consideration of SO_2 related air quality measures into their 111(d) planning. The EPA intends to address the designations for all other areas in three separate actions in the future.[1035] These designations must be completed by no later than July 2, 2016, December 31, 2017, and December 31, 2020 with attainment plans due between 2018 and 2022.

Regarding requirements under the regional haze program, several affected EGUs have deadlines in the 2016–2021 timeframe to install controls to comply with the Best Available Retrofit Technology (BART) and reasonable progress requirements of the Regional Haze Rule. Soon after these deadlines, some of the same affected EGUs may be required to reduce their utilization, convert into natural gas-fired facilities, or shut down entirely as a result of state 111(d) plans. Some commenters have expressed concern that for these affected EGUs, specifically those that choose to retire, the capital equipment installed to comply with the Regional Haze Rule would likely become stranded assets.

While the EPA is providing considerable flexibility for states and sources under the final 111(d) emission guidelines, the EPA acknowledges the possibility that some sources could ultimately be faced with the potential for stranded assets as a result of state 111(d) plans. For these sources, however, states have the option of developing BART alternatives that replace control requirements that would otherwise result in stranded assets at a particular EGU with the aggregate emission reductions that will result from retirements, fuel switching, reduced utilization, or lesser controls at multiple EGUs.

In fact, the EPA already has experience working with states to account for these very types of changed circumstances.[1036] The EPA will continue to work with states to explore options for integrating compliance requirements across multiple regulatory programs, as warranted.

The EPA believes that CAA section 111(d) efforts and actions will tend to contribute to overall air quality improvements and thus should be complementary to criteria pollutant and regional haze SIP efforts.

7. Final Rule Flexibilities

As discussed in Section VIII of this preamble, the EPA is providing states flexibility in developing approvable plans under CAA section 111(d), including the ability to impose source-by-source limitations reflecting the BSER performance rates to each affected EGU or to adopt rate-based or mass-based emission performance goals, and to rely on a wide range of CO_2 emission reduction measures, including measures that are not part of the BSER. The EPA is also providing states considerable flexibility with respect to the timeframes for plan development and implementation, with up to 3 years permitted for final plans to be submitted after the GHG emission guidelines are finalized, and up to 15 years for all emission reduction measures to be fully implemented. The EPA is establishing an 8-year interim period over which to achieve the full required reductions to meet the CO_2 performance rates, and this begins in 2022, more than seven years from the June 18, 2014 date of proposal of the rulemaking. The 8-year interim period from 2022 through 2029, is separated into three steps, 2022–2024, 2025–2027, and 2028–2029, each associated with its own interim CO_2 emission performance rates.

In light of these broad flexibilities, we believe that states will have ample opportunity, when developing and implementing their CAA section 111(d) plans, to coordinate their response to this requirement with source and state responses to any obligations that may be applicable to affected EGUs as a result of the MATS, CSAPR, 316(b), SE ELG and CCR rules, all of which are or soon will be final rules. In addition, we believe that states will be able to design CAA section 111(d) plans that use innovative, cost-effective regulatory strategies, that spark investment and innovation across a wide variety of clean energy technologies, and that will help reduce cost and ensure reliability, while also ensuring that all applicable environmental requirements are met.[1037] We also believe that the broad

[1035] The EPA has developed a comprehensive implementation strategy for these future actions that focuses resources on identifying and addressing unhealthy levels of SO_2 in areas where people are most likely to be exposed to violations of the standard. The strategy is available at *http://www.epa.gov/airquality/sulfurdioxide/implement.html*, and the associated area designations schedule is at *http://www.epa.gov/airquality/sulfurdioxide/designations/pdfs/201503Schedule.pdf*.

[1036] For example, Oregon replaced its BART determination for the Boardman Coal Plant with a new requirement that accounted for a planned shutdown before the EPA took action on the state's SIP submission (76 FR 12661). Washington similarly replaced its BART determination for the TransAlta Centralia Power Plant before the EPA took action on the state's SIP submission (77 FR 72742). Oklahoma submitted a SIP revision with a new BART determination for the AEP/PSO Northeastern Power Station, which included enforceable requirements for reduced utilization and early unit retirements, to replace a FIP that had been promulgated by the EPA (79 FR 12944). Finally, the EPA finalized a BART determination for Unit 3 at the Dave Johnston Power Plant in Wyoming that included two compliance options, one of which included a federally enforceable retirement date and less costly controls.

[1037] It should be noted that regulatory obligations imposed upon states and sources operate independently under different statutes and sections of statutes; the EPA expects that states and sources will take advantage of available flexibilities as

Continued

flexibilities in this action will enable states and affected EGUs to build on their longstanding, successful records of complying with multiple CAA, CWA, and other environmental requirements, while assuring an adequate, affordable, and reliable supply of electricity.

XI. Impacts of This Action [1038]

A. What are the air impacts?

The EPA anticipates significant emission reductions under the final guidelines for the utility power sector. In the final emission guidelines, the EPA has translated the source category-specific CO_2 emission performance rates into equivalent state-level rate-based and mass-based CO_2 goals in order to maximize the range of choices that states will have in developing their plans. Because of the range of choices available to states and the lack of *a priori* knowledge about the specific choices states will make in response to the final goals, the Regulatory Impact Analysis (RIA) for this final action presents two scenarios designed to achieve these goals, which we term the ''rate-based'' illustrative plan approach and the ''mass-based'' illustrative plan approach.[1039]

Under the rate-based approach, when compared to 2005, CO_2 emissions are projected to be reduced by approximately 22 percent in 2020, 28 percent in 2025, and 32 percent in 2030. Under the mass-based approach, when compared to 2005, CO_2 emissions are projected to be reduced by approximately 23 percent in 2020, 29 percent in 2025, and 32 percent in 2030. The final guidelines are projected to result in substantial co-benefits through reductions of SO_2, NO_X and $PM_{2.5}$ that will have direct public health benefits by lowering ambient levels of these pollutants and ozone. Tables 15 and 16 show expected CO_2 and other air pollutant emissions in the base case and reductions under the final guidelines for 2020, 2025, and 2030 for the rate-based and mass-based approaches, respectively.

TABLE 15—SUMMARY OF CO_2 AND OTHER AIR POLLUTANT EMISSION REDUCTIONS FROM THE BASE CASE UNDER RATE-BASED ILLUSTRATIVE PLAN APPROACH

	CO_2 (millions short tons)	SO_2 (thousand short tons)	NO_X (thousand short tons)
2020 Final Guidelines:			
Base Case	2,155	1,311	1,333
Final Guidelines	2,085	1,297	1,282
Emissions Reductions	69	14	50
2025 Final Guidelines:			
Base Case	2,165	1,275	1,302
Final Guidelines	1,933	1,097	1,138
Emissions Reductions	232	178	165
2030 Final Guidelines:			
Base Case	2,227	1,314	1,293
Final Guidelines	1,812	996	1,011
Emissions Reductions	415	318	282

Source: Integrated Planning Model, 2015.
Note: Emissions may not sum due to rounding.

TABLE 16—SUMMARY OF CO_2 AND OTHER AIR POLLUTANT EMISSION REDUCTIONS FROM THE BASE CASE UNDER MASS-BASED ILLUSTRATIVE PLAN APPROACH

	CO_2 (million short tons)	SO_2 (thousand short tons)	NO_X (thousand short tons)
2020 Final Guidelines:			
Base Case	2,155	1,311	1,333
Final Guidelines	2,073	1,257	1,272
Emissions Reductions	81	54	60
2025 Final Guidelines:			
Base Case	2,165	1,275	1,302
Final Guidelines	1,901	1,090	1,100
Emissions Reductions	265	185	203
2030 Final Guidelines:			
Base Case	2,227	1,314	1,293
Final Guidelines	1,814	1,034	1,015
Emissions Reductions	413	280	278

Source: Integrated Planning Model, 2015.
Note: Emissions may not sum due to rounding.

appropriate, but will comply with all relevant legal requirements.

[1038] The impacts presented in this section of the preamble represent an illustrative implementation of the guidelines. As states implement the final guidelines, they have sufficient flexibility to adopt different state-level or regional approaches that may yield different costs, benefits, and environmental impacts. For example, states may use the flexibilities described in these guidelines to find approaches that are more cost-effective for their particular state or choose approaches that shift the balance of co-benefits and impacts to match broader state priorities.

[1039] It is important to note that the differences between the analytical results for the rate-based and mass-based illustrative plan approaches presented in the RIA may not be indicative of likely differences between the approaches if implemented by states and affected EGUs in response to the final guidelines. If one approach performs differently than the other on a given metric during a given time period, this does not imply this will apply in all instances.

The reductions in Tables 15 and 16 do not account for reductions in hazardous air pollutants (HAPs) that may occur as a result of this rule. For instance, the fine particulate reductions presented above do not reflect all of the reductions in many heavy metal particulates.

B. Endangered Species Act

As explained in the preamble to the proposed rule (79 FR at 34933–934), the EPA has carefully considered the requirements of section 7(a)(2) of the Endangered Species Act (ESA) and applicable ESA regulations, and reviewed relevant ESA case law and guidance, to determine whether consultation with the U.S. Fish and Wildlife Service (FWS) and/or National Marine Fisheries Service (together, the Services) is required by the ESA. The EPA proposed to conclude that the requirements of ESA section 7(a)(2) would not be triggered by promulgation of the rule, and we now finalize that determination.

Section 7(a)(2) of the ESA requires federal agencies, in consultation with one or both of the Services (depending on the species at issue), to ensure that actions they authorize, fund, or carry out are not likely to jeopardize the continued existence of federally listed endangered or threatened species or result in the destruction or adverse modification of designated critical habitat of such species. 16 U.S.C. 1536(a)(2). Under relevant implementing regulations, section 7(a)(2) applies only to actions where there is discretionary federal involvement or control. 50 CFR 402.03. Further, under the regulations consultation is required only for actions that ''may affect'' listed species or designated critical habitat. 50 CFR 402.14. Consultation is not required where the action has no effect on such species or habitat. Under this standard, it is the federal agency taking the action that evaluates the action and determines whether consultation is required. *See* 51 FR 19926, 19949 (June 3, 1986). Effects of an action include both the direct and indirect effects that will be added to the environmental baseline. 50 CFR 402.02. Direct effects are the direct or immediate effects of an action on a listed species or its habitat.[1040] Indirect effects are those that are ''caused by the proposed action and are later in time, but still are reasonably certain to occur.'' *Id.* To trigger the consultation requirement, there must thus be a causal connection between the federal action, the effect in question, and the listed species, and if the effect is indirect, it must be reasonably certain to occur.

The EPA notes that the projected environmental effects of this rule are positive: Reductions in overall GHG emissions, and reductions in PM and ozone-precursor emissions (SO_2 and NO_X). The EPA recognizes that beneficial effects to listed species can, as a general matter, result in a ''may affect'' determination under the ESA. However, the EPA's assessment that the rule will have an overall net positive environmental effect by virtue of reducing emissions of certain air pollutants does not address whether the rule may affect any listed species or designated critical habitat for ESA section 7(a)(2) purposes and does not constitute any finding of effects for that purpose. The fact that the rule will have overall positive effects on the national and global environment does not mean that the rule may affect any listed species in its habitat or the designated critical habitat of such species within the meaning of ESA section 7(a)(2) or the implementing regulations or require ESA consultation. The EPA has considered various types of potential effects in reaching the conclusion that ESA consultation is not required for this rule.

With respect to the projected GHG emission reductions, the EPA considered in detail in the proposal why such reductions do not trigger ESA consultation requirements under section 7(a)(2). As explained in the proposal, in reaching this conclusion the EPA was mindful of significant legal and technical analysis undertaken by FWS and the U.S. Department of the Interior (DOI) in the context of listing the polar bear as a threatened species under the ESA. In that context, in 2008, FWS and DOI expressed the view that the best scientific data available were insufficient to draw a causal connection between GHG emissions and effects on the species in its habitat.[1041] The DOI Solicitor concluded that where the effect at issue is climate change, proposed actions involving GHG emissions cannot pass the ''may affect'' test of the section 7 regulations and thus are not subject to ESA consultation.

As described in the proposal, the EPA has also previously considered issues relating to GHG emissions in connection with the requirements of ESA section 7(a)(2) and has supplemented DOI's analysis with additional consideration of GHG modeling tools and data regarding listed species. Although the GHG emission reductions projected for this final rule are large (estimated reductions of about 415 million short tons of CO_2 in 2030 relative to the base case under the rate-based illustrative plan approach—see Table 14 above), the EPA evaluated larger reductions in assessing this same issue in the context of the light-duty vehicle GHG emission standards for model years 2012–2016 and 2017–2025. There the agency projected emission reductions over the lifetimes of the model years in question [1042] which are roughly five to six times those projected above and, based on air quality modeling of potential environmental effects, concluded that ''EPA knows of no modeling tool which can link these small, time-attenuated changes in global metrics to particular effects on listed species in particular areas. Extrapolating from global metric to local effect with such small numbers, and accounting for further links in a causative chain, remain beyond current modeling capabilities.'' [1043] The EPA reached this conclusion after evaluating issues relating to potential improvements relevant to both temperature and oceanographic pH outputs. The EPA's ultimate finding was that ''any potential for a specific impact on listed species in their habitats associated with these very small changes in average global temperature and ocean pH is too remote to trigger the threshold for ESA section 7(a)(2).'' *Id.* The EPA believes that the same conclusion applies to the present rule. *See, e.g., Ground Zero Center for Non-Violent Action* v. *U.S. Dept. of Navy,* 383 F. 3d 1082, 1091–92 (9th Cir. 2004) (where the likelihood of jeopardy to a species from a federal action is extremely remote, ESA does not require consultation). The EPA's conclusion is entirely consistent with DOI's analysis regarding ESA requirements in the

[1040] *See* Endangered Species Consultation Handbook, U.S. Fish & Wildlife Service and National Marine Fisheries Service at 4–25 (March 1998) (providing examples of direct effects: *e.g.,* driving an off road vehicle through the nesting habitat of a listed species of bird and destroying a ground nest; building a housing unit and destroying the habitat of a listed species). Available at *https://www.fws.gov/ENDANGERED/esa-library/pdf/esa_section7_handbook.pdf.*

[1041] *See, e.g.,* 73 FR 28212, 28300 (May 15, 2008); Memorandum from David Longly Bernhardt, Solicitor, U.S. Department of the Interior re: ''Guidance on the Applicability of the Endangered Species Act's Consultation Requirements to Proposed Actions Involving the Emission of Greenhouse Gases'' (Oct. 3, 2008). Available at *http://www.doi.gov/solicitor/opinions/M-37017.pdf.*

[1042] *See* 75 FR at 25438 Table I.C 2–4 (May 7, 2010); 77 FR at 62894 Table III–68 (Oct. 15, 2012).

[1043] EPA, Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards, Response to Comment Document for Joint Rulemaking at 4–102 (Docket ID EPA–OAR–HQ–2010–0799). Available at *http://www.epa.gov/otaq/climate/regulations/420r10012a.pdf.*

context of federal actions involving GHG emissions.[1044]

With regard to non-GHG air emissions, the EPA also projects substantial reductions of SO_2 and NO_X as a collateral consequence of this final action. However, CAA section 111(d)(1) standards cannot directly control emissions of criteria pollutants. See CAA section 111(d)(1)(i). Consequently, CAA section 111(d) provides no discretion to adjust the standard based on potential impacts to endangered species of reduced criteria pollutant emissions. Section 7(a)(2) consultation thus is not required with respect to the projected reductions of criteria pollutant emissions. *See* 50 CFR 402.03; *see also, WildEarth Guardians* v. *U.S. Envt'l Protection Agency,* 759 F.3d 1196, 1207–10 (10th Cir. 2014) (EPA has no duty to consult under section 7(a)(2) of the ESA regarding hazardous air pollutant controls that it did not require—and likely lacked authority to require—in a federal implementation plan for regional haze controls under section 169A of the CAA).

Finally, the EPA has also considered other potential effects of the rule (beyond reductions in air pollutants) and whether any such effects are ''caused by'' the rule and ''reasonably certain to occur'' within the meaning of the ESA regulatory definition of the effects of an action. 50 CFR 402.02. As the EPA noted in the proposal, there are substantial questions as to whether any potential for relevant effects results from any element of the rule or would result instead from separate decisions and actions made in connection with the development, implementation, and enforcement of a plan to implement the standards established in the rule. *Cf. American Trucking Assn's* v. *EPA,* 175 F. 3d 1027, 1043–45 (D.C. Cir. 1999), *rev'd on different grounds sub nom., Whitman* v. *American Trucking Assn's,* 531 U.S. 457 (2000) (National Ambient Air Quality Standards have no economic impact, for purposes of Regulatory Flexibility Act, because impacts result from the actions of states through their development, implementation and enforcement of SIPs).[1045] The EPA recognized, for instance, that questions may exist whether decisions such as increased utilization of solar or wind power could have effects on listed species. The EPA received comments on the proposal asserting that because potential increased reliance on wind or solar power may be an element of building block 3, and because wind and solar facilities may in some cases have effects on listed species, the EPA must consult under the ESA on this aspect of the rule. The EPA is also aware of certain questions regarding potential effects of the rule on the Big Bend Power Station located in Florida, which discharges effluent that provides a warm water refuge for manatees. The Big Bend Power Station and another coal-fired facility located in Florida—the Crystal River Plant—are, for example, referenced in the June 11, 2015, and June 15, 2015, congressional letters to EPA cited above.

The EPA has carefully considered the comments and the correspondence from Congress as well as the case law and other materials cited in those documents. The EPA does not believe that the effects of potential future changes in the energy sector—including increased reliance on wind or solar power as a result of future potential actions by states or other implementing entities—or any potential alterations in the operations of any particular facility are caused by the current rule or sufficiently certain to occur so as to require ESA consultation on the rule. The EPA appreciates that the ESA regulations call for consultation where actions authorized, funded, or carried out by federal agencies may have indirect effects on listed species or designated critical habitat. However, as noted above, indirect effects must be caused by the action at issue and must be reasonably certain to occur. At this point, there is no reasonable certainty regarding implementation of any planning measures in any location, let alone in any location occupied by a listed species or its designated critical habitat. The EPA cannot predict with reasonable certainty where such measures may take effect or which measures may be adopted. It is not clear, for instance, whether a particular implementation plan will call, if at all, for increased reliance on wind power, as opposed to solar power, or on some other form of low or zero carbon emitting generation. It is also entirely uncertain how a future implementation plan for a particular state might affect, if at all, operations at a specific facility.[1046] The precise steps included in an implementation plan cannot be determined or ordered by this federal action, and they are not sufficiently certain to be attributable to this final rule for ESA purposes. These steps will flow from a series of later in time decisions generally made by other entities—usually states—in their

[1044] The EPA has received correspondence from a U.S. Senator and a Member of the U.S. House of Representatives noting that the Services have identified several listed species affected by global climate change. *See* Letter from Rob Bishop, Chairman, House Committee on Natural Resources, to Gina McCarthy, Administrator, U.S. Environmental Protection Agency, dated June 11, 2015; Letter from Rob Bishop, Chairman, House Committee on Natural Resources, and James M. Inhofe, Chairman, Senate Committee on Environment and Public Works, to Gina McCarthy, Administrator, U.S. Environmental Protection Agency, dated June 15, 2015. EPA's assessment of ESA requirements in connection with the present rule does not address whether global climate change may, as a general matter, be a relevant consideration in the status of certain listed species. Rather, the requirements of ESA section 7(a)(2) must be considered and applied to the specific action at issue. As explained above, EPA's conclusion that ESA section 7(a)(2) consultation is not required here is premised on the specific facts and circumstances of the present rule and is fully consistent with prior relevant analyses conducted by DOI, FWS, and EPA.

[1045] One commenter questioned the EPA's citation to *American Trucking Assn's.* As stated by the commenter, the statute at issue in that case—the Regulatory Flexibility Act (RFA)—is distinguishable from the ESA in that it addresses only direct effects and does not consider indirect effects. The commenter misreads the EPA's citation to this case. The EPA cites this case simply to reference a decision considering the impacts of an EPA action—the revision of a NAAQS under the CAA—that in certain respects provides a useful analogy to the present rule. A NAAQS is implemented through a series of subsequent planning decisions generally taken by states by means of adoption of SIPs. States can choose to impose or avoid the types of impacts at issue in the D.C. Circuit case through their planning decisions; thus such impacts were not viewed as having been caused—for purposes of the RFA—by the EPA's promulgation of the revised NAAQS in the first instance. The standard setting and implementation mechanisms under section 111(d) are very similar. Under section 111(d), the EPA is required to establish ''a procedure similar to that provided by section 7410''—the provision establishing the SIP mechanism for implementing NAAQS. Thus, the D.C. Circuit's discussion provides a useful analogy to the present rule and the various types of potential effects that may be attributable to future implementation planning decisions by states and other entities as they exercise their discretion in determining how to implement the federal guidelines, but not to promulgation of the rule itself. The EPA's citation to this case was not intended to address any comparison of the scope of effects covered by the RFA and the effects cognizable under section 7(a)(2) of the ESA. The EPA is aware that the ESA addresses both direct and indirect effects as defined by the applicable ESA regulations. The discussion supporting the EPA's ESA conclusion expressly acknowledges the relevance of indirect effects to the ESA analysis and explains why such effects are not present here.

[1046] A congressional letter of June 11, 2015, referenced above asserts that EPA's modeling suggests that the Big Bend Power Station and Crystal River Energy Complex in Florida will be prematurely retired as a result of the rule. EPA notes that any such facility-level projections associated with the rule cannot be stated with sufficient certainty to qualify as potential indirect effects under the ESA. These projections are based on numerous assumptions regarding a variety of planning and business decisions yet to be made by the implementing governments (usually states) and facility owners. Given the wide degrees of discretion and flexibility and the numerous options available for such decision making, the potential for such outcomes to be realized as currently projected is at this point too uncertain to qualify as an effect under the ESA.

distinct planning processes. These later decisions cannot now be required by the rule, are not caused by the rule, and are not reasonably certain to occur. The EPA also notes that the plans adopted for particular states may themselves provide wide degrees of implementation flexibility, thus further increasing the uncertainty that any species-impacting activity will occur in any particular location, if at all. The Services have explained that section 7(a)(2) was not intended to preclude federal actions based on potential future speculative effects.[1047] These are precisely the types of speculative future activities and effects at issue here.[1048] For this additional reason, the EPA concludes that the rule does not have effects on listed species that trigger the section 7(a)(2) consultation requirement.[1049]

C. What are the energy impacts?

The final guidelines have important energy market implications. Table 17 presents a variety of important energy market impacts for 2020, 2025, and 2030 under both the rate-based and mass-based illustrative plan approaches.

TABLE 17—SUMMARY TABLE OF IMPORTANT ENERGY MARKET IMPACTS FOR RATE-BASED AND MASS-BASED ILLUSTRATIVE PLAN APPROACHES

[Percent change from base case]

	Rate-based			Mass-based		
	2020	2025	2030	2020	2025	2030
Retail electricity prices	3	1	1	3	2	0
Price of coal at minemouth	−1	−5	−4	−1	−5	−3
Coal production for power sector use	−5	−14	−25	−7	−17	−24
Price of natural gas delivered to power sector	5	−8	2	4	−3	−2
Natural gas use for electricity generation	3	−1	−1	5	0	−4

These figures reflect the EPA's illustrative modeling that presumes policies that lead to generation shifts and growing use of demand-side EE and renewable electricity generation out to 2029. If states make different policy choices, impacts could be different. For instance, if states implement renewable and/or demand-side EE policies on a more aggressive time-frame, impacts on natural gas and electricity prices would likely be less. Implementation of other measures not included in the BSER calculation or compliance modeling, such as nuclear uprates, transmission system improvements, use of energy storage technologies or retrofit CCS, could also mitigate gas price and/or electricity price impacts.

Energy market impacts from the guidelines are discussed more extensively in the RIA found in the docket for this rulemaking.

D. What are the compliance costs?

The compliance costs of this final action are represented in this analysis as the change in electric power generation costs between the base case and the final rule in which states pursue a distinct set of strategies beyond the strategies taken in the base case to meet the terms of the final guidelines. The compliance costs estimates include cost estimates for demand-side EE. The compliance assumptions—and, therefore, the projected compliance costs—set forth in this analysis are illustrative in nature and do not represent the full suite of compliance flexibilities states may ultimately pursue. The illustrative analysis is designed to reflect, to the extent possible, the scope and the nature of the final guidelines. However, there is considerable uncertainty with regards to the precise measures that states will adopt to meet the final requirements, because there are considerable flexibilities afforded to the states in developing their state plans.

The incremental cost is the projected additional cost of complying with the guidelines in the year analyzed and includes the amortized cost of capital investment, needed new capacity, shifts between or amongst various fuels, deployment of demand-side EE programs, and other actions associated with compliance. These important

[1047] *See* 51 FR at 19933 (describing effects that are ''reasonably certain to occur'' in the context of consideration of cumulative effects and distinguishing broader consideration that may be appropriate in applying a procedural statute such as the National Environmental Policy Act, as opposed to a substantive provision such as ESA section 7(a)(2) that may prohibit certain federal actions); Endangered Species Consultation Handbook, U.S. Fish & Wildlife Service and National Marine Fisheries Service at 4–30 (March 1998) (in the same context, describing indicators that an activity is reasonably certain to occur as including governmental approvals of the action or indications that such approval is imminent, project sponsors' assurance that the action will proceed, obligation of venture capital, or initiation of contracts; and noting that the more governmental administrative discretion remains to be exercised, the less there is reasonable certainty the action will proceed). Available at *https://www.fws.gov/ENDANGERED/esa-library/pdf/esa_section7_handbook.pdf*.

[1048] EPA also notes that some of the future implementing activities may involve federal actions that are subject to ESA consultation, thus providing consideration of any impacts on listed species at the appropriate point when particular activities have become reasonably certain. Several commenters on the proposal specifically noted that such future activities—*e.g.,* development of additional RE facilities such as wind farms—may call for ESA consultation. Further, EPA notes that section 9 of the ESA, which prohibits the take of individuals of most listed species, provides an additional protection for listed species as future implementing activities become reasonably certain.

[1049] The commenters cite certain cases that they assert support consulting under ESA section 7(a)(2). The EPA has considered these cases, each of which is distinguishable from the present rule. By way of example, a commenter cites two cases involving EPA actions: *Defenders of Wildlife* v. *EPA,* 420 F.3d 946 (9th Cir. 2005), *rev'd, National Association of Homebuilders* v. *Defenders of Wildlife,* 551 U.S. 644 (2007); and *Washington Toxics Coalition* v. *EPA,* 413 F.3d 1024 (9th Cir. 2005). In *Defenders of Wildlife* (a decision that was reversed by the U.S. Supreme Court), a principal relevant impact of the federal action at issue—the EPA's approval of a state's permitting program under the Clean Water Act—was that following the action, the relevant permitted activities would no longer be subject to consultation under the ESA. By contrast, promulgation of the present rule will result in no change to any ESA requirements applicable to any future activities directed by plans (either state or federal) implementing the rule. The action at issue in *Washington Toxics Coalition* involved the EPA's registration of certain pesticide active ingredients under the Federal Insecticide, Fungicide, and Rodenticide Act. Such actions provide authorization for the sale and distribution of those products, consistent with applicable labelling requirements. The EPA also notes that under the EPA's regulations, registered pesticide labels must, among other things, specify the product ingredients and the methods and sites of product application. 40 CFR 156.10. By contrast, the present rule only sets goals and describes potential pathways to meeting those goals, all of which are subject to future considerations and decisions involved in the implementation of plans (generally by states). The rule neither authorizes, nor directs, any of the future measures to meet the rule's goals. Those activities remain subject to the full range of future decision making addressing which types of measures to implement, what emitting entities will be affected, how much, and when.

dynamics are discussed in more detail in the RIA in the rulemaking docket.

The EPA estimates the annual incremental compliance cost for the rate-based approach for final emission guidelines to be $2.5 billion in 2020, $1.0 billion in 2025 and $8.4 billion in 2030, including the costs associated with monitoring, reporting, and recordkeeping (MR&R).[1050] The EPA estimates the annual incremental compliance cost for the mass-based approach for final emission guidelines to be $1.4 billion in 2020, $3.0 billion in 2025 and $5.1 billion in 2030, including the costs associated with MR&R.

More detailed cost estimates are available in the RIA included in the rulemaking docket.

E. What are the economic and employment impacts?

The final standards are projected to result in certain changes to power system operation as a compliance with the standards. See Table 16 above for a variety of important energy market impacts for 2020, 2025, and 2030 under both the rate-based and mass-based illustrative plan approaches.

It is important to note that the EPA's modeling does not necessarily account for all of the factors that may influence business decisions regarding future coal-fired capacity. Many power companies already factor a potential financial liability associated with carbon emissions into their long term capacity planning that would further influence business decisions to replace these aging assets with modern, and significantly cleaner, generation.

The compliance modeling done to support the final rule assumes that overall electric demand will decrease as states ramp up programs that result in lower overall demand. Demand-side EE levels are expected to increase such that they achieve about a 7.8 percent reduction on overall electricity demand levels in 2030 under the final guidelines.

Changes in price or demand for electricity, natural gas, and coal can impact markets for goods and services produced by sectors that use these energy inputs in the production process or supply those sectors. Changes in the cost of production may result in changes in prices, quantities produced, and profitability of affected firms. The EPA recognizes that these guidelines provide significant flexibilities and states implementing the guidelines may choose to mitigate impacts to some markets outside the utility power sector. Similarly, demand for new generation or demand-side EE as a result of states implementing the guidelines can result in shifts in production and profitability for firms that supply those goods and services.

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. While the economy continues moving toward full-employment, employment impacts are of particular concern and questions may arise about their existence and magnitude.

States have the responsibility and flexibility to implement policies and practices for compliance with the final guidelines. Quantifying the associated employment impacts is complicated by the wide range of approaches that states may use. As such, the EPA's employment analysis includes projected employment impacts associated with illustrative plan approaches for these guidelines for the electric power industry, coal and natural gas production, and demand-side EE activities. These projections are derived, in part, from a detailed model of the utility power sector used for this regulatory analysis, and U.S government data on employment and labor productivity. In the electricity, coal, and natural gas sectors, the EPA estimates that these guidelines could result in a net decrease of approximately 25,000 job-years in 2025 for the final guidelines under the rate-based illustrative plan approach and approximately 26,000 job-years in 2025 under the mass-based approach. For 2030, the estimates of the net decrease in job-years are 31,000 under the rate-based approach and 34,000 under the mass-based approach. The agency is also offering an illustrative calculation of potential employment effects due to demand-side EE programs. Employment impacts from demand-side energy EE programs in 2030 could range from approximately 52,000 to 83,000 jobs under the final guidelines.

By its nature, demand-side EE reduces overall demand for electric power. The EPA recognizes as more efficiency is built into the U.S. power system over time, lower fuel requirements may lead to fewer jobs in the coal and natural gas extraction sectors, as well as in fossil-fuel fired EGU construction and operation than would otherwise have been expected. The EPA also recognizes the fact that, in many cases, employment gains and losses that might be attributable to this rule would be expected to affect different sets of people. Moreover, workers who lose jobs in these sectors may find employment elsewhere just as workers employed in new jobs in these sectors may have been previously employed elsewhere. Therefore, the employment estimates reported in these sectors may include workers previously employed elsewhere. This analysis also does not capture potential economy-wide impacts due to changes in prices (of fuel, electricity, labor, for example) or other factors such as improved labor productivity and reduced health care expenditures resulting from cleaner air. For these reasons, the numbers reported here should not be interpreted as a net national employment impact.

F. What are the benefits of the final goals?

Implementing the final standards will generate benefits by reducing emissions of CO_2 and criteria pollutant precursors, including SO_2, NO_X, and directly-emitted particles. SO_2 and NO_X are precursors to $PM_{2.5}$ (particles smaller than 2.5 microns), and NO_X is a precursor to ozone. The estimated benefits associated with these emission reductions are beyond those achieved by previous EPA rulemakings including the Mercury and Air Toxics Standards rule. The health and welfare benefits from reducing air pollution are considered co-benefits for these standards. For this rulemaking, we were only able to quantify the climate benefits from reduced emissions of CO_2 and the health co-benefits associated with reduced exposure to $PM_{2.5}$ and ozone. There are many additional benefits which we are not able to quantify, leading to an underestimate of monetized benefits. In summary, we estimate the total combined climate benefits and health co-benefits for the rate-based approach to be $3.5 to $4.6 billion in 2020, $18 to $28 billion in 2025, and $34 to $54 billion in 2030 (3 percent discount rate, 2011$). Total combined climate benefits and health co-benefits for the mass-based approach are estimated to be $5.3 to $8.1 billion in 2020, $19 to $29 billion in 2025, and

[1050] The MR&R costs estimates are $65 million in 2020, $15 million in 2025 and $15 million in 2030 and are assumed to be the same for both rate-based and mass-based illustrative plan approaches.

$32 to $48 billion in 2030 (3 percent discount rate, 2011$). A summary of the emission reductions and monetized benefits estimated for this rule at all discount rates is provided in Tables 15 through 22 of this preamble.

TABLE 18—SUMMARY OF THE MONETIZED GLOBAL CLIMATE BENEFITS FOR THE FINAL GUIDELINES

[Billions of 2011$] [a]

Year	Discount rate (statistic)	Monetized climate benefits		
		2020	2025	2030
Rate-based Approach				
CO_2 Reductions (million short tons)		69	232	415
	5 percent (average SC-CO_2)	$0.80	$3.1	$6.4
	3 percent (average SC-CO_2)	$2.8	$10	$20
	2.5 percent (average SC-CO_2)	$4.1	$15	$29
	3 percent (95th percentile SC-CO_2)	$8.2	$31	$61
Mass-based Approach				
CO_2 Reductions (million short tons)		81	265	413
	5 percent (average SC-CO_2)	$0.94	$3.6	$6.4
	3 percent (average SC-CO_2)	$3.3	$12	$20
	2.5 percent (average SC-CO_2)	$4.9	$17	$29
	3 percent (95th percentile SC-CO_2)	$9.7	$35	$60

[a] Climate benefit estimates reflect impacts from CO_2 emission changes in the analysis years presented in the table and do not account for changes in non-CO_2 GHG emissions. These estimates are based on the global social cost of carbon (SC-CO_2) estimates for the analysis years and are rounded to two significant figures.

TABLE 19—SUMMARY OF THE MONETIZED HEALTH CO-BENEFITS IN THE U.S. FOR THE FINAL GUIDELINES, RATE-BASED APPROACH

[Billions of 2011$] [a]

Pollutant	National emission reductions (thousands of short tons)	Monetized health co-benefits (3 percent discount)	Monetized Health Co-benefits (7 percent discount)
Final Guidelines, Rate-based Approach, 2020			
$PM_{2.5}$ precursors: [b]			
SO_2	14	$0.44 to $0.99	$0.39 to $0.89
NO_X	50	$0.14 to $0.33	$0.13 to $0.30
Ozone precursor: [c]			
NO_X (ozone season only)	19	$0.12 to $0.52	$0.12 to $0.52
Total Monetized Health Co-benefits		$0.70 to $1.8	$0.64 to $1.7
Total Monetized Health Co-benefits combined with Monetized Climate Benefits [d]		$3.5 to $4.6	$3.5 to $4.5
Final Guidelines, Rate-based Approach, 2025			
$PM_{2.5}$ precursors: [b]			
SO_2	178	$6.4 to $14	$5.7 to $13
NO_X	165	$0.56 to $1.3	$0.50 to $1.1
Ozone precursor: [c]			
NO_X (ozone season only)	70	$0.49 to $2.1	$0.49 to $2.1
Total Monetized Health Co-benefits		$7.4 to $18	$6.7 to $16
Total Monetized Health Co-benefits combined with Monetized Climate Benefits [d]		$18 to $28	$17 to $26
Final Guidelines, Rate-based Approach, 2030			
$PM_{2.5}$ precursors: [b]			
SO_2	318	$12 to $28	$11 to $25
NO_X	282	$1.0 to $2.3	$0.93 to $2.1
Ozone precursor: [c]			
NO_X (ozone season only)	118	$0.86 to $3.7	$0.86 to $3.7
Total Monetized Health Co-benefits		$14 to $34	$13 to $31
Total Monetized Health Co-benefits combined with Monetized Climate Benefits. [d]		$34 to $54	$33 to $51

[a] All estimates are rounded to two significant figures, so estimates may not sum. It is important to note that the monetized co-benefits do not include reduced health effects from direct exposure to SO_2, direct exposure to NO_2, exposure to mercury, ecosystem effects or visibility impairment. Air pollution health co-benefits are estimated using regional benefit-per-ton estimates for the contiguous U.S.

[b] The monetized $PM_{2.5}$ co-benefits reflect the human health benefits associated with reducing exposure to $PM_{2.5}$ through reductions of $PM_{2.5}$ precursors, such as SO_2 and NO_X. The co-benefits do not include the benefits of reductions in directly emitted $PM_{2.5}$. These additional benefits would increase overall benefits by a few percent based on the analyses conducted for the proposed rule. PM co-benefits are shown as a range reflecting the use of two concentration-response functions, with the lower end of the range based on a function from Krewski et al. (2009) and the upper end based on a function from Lepeule et al. (2012). These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effect estimates by particle type.

[c] The monetized ozone co-benefits reflect the human health benefits associated with reducing exposure to ozone through reductions of NO_X during the ozone season. Ozone co-benefits are shown as a range reflecting the use of several different concentration-response functions, with the lower end of the range based on a function from Bell, et al. (2004) and the upper end based on a function from Levy, et al. (2005). Ozone co-benefits occur in the analysis year, so they are the same for all discount rates.

[d] We estimate climate benefits associated with four different values of a one ton CO_2 reduction (model average at 2.5 percent discount rate, 3 percent, and 5 percent; 95th percentile at 3 percent). Referred to as the social cost of carbon, each value increases over time. 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 carbon values. We provide combined climate and health estimates based on additional discount rates in the RIA.

TABLE 20—SUMMARY OF THE MONETIZED HEALTH CO-BENEFITS IN THE U.S. FOR THE FINAL GUIDELINES, MASS-BASED APPROACH

[Billions of 2011$] [a]

Pollutant	National emission reductions (thousands of short tons)	Monetized health co-benefits (3 percent discount)	Monetized health co-benefits (7 percent discount)
Final Guidelines, Mass-based Approach, 2020			
$PM_{2.5}$ precursors: [b]			
SO_2	54	$1.7 to $3.8	$1.5 to $3.4
NO_X	60	$0.17 to $0.39	$0.16 to $0.36
Ozone precursor: [c]			
NO_X (ozone season only)	23	$0.14 to $0.61	$0.14 to $0.61
Total Monetized Health Co-benefits		$2.0 to $4.8	$1.8 to $4.4
Total Monetized Health Co-benefits combined with Monetized Climate Benefits [d]		$5.3 to $8.1	$5.1 to $7.7
Final Guidelines, Mass-based Approach, 2025			
$PM_{2.5}$ precursors: [b]			
SO_2	185	$6.0 to $13	$5.4 to $12
NO_X	203	$0.58 to $1.3	$0.52 to $1.2
Ozone precursor: [c]			
NO_X (ozone season only)	88	$0.56 to $2.4	$0.56 to $2.4
Total Monetized Health Co-benefits		$7.1 to $17	$6.5 to $16
Total Monetized Health Co-benefits combined with Monetized Climate Benefits [d]		$19 to $29	$18 to $27
Final Guidelines, Mass-based Approach, 2030			
$PM_{2.5}$ precursors: [b]			
SO_2	280	$10 to $23	$9.0 to $20
NO_X	278	$0.87 to $2.0	$0.79 to $1.8
Ozone precursor: [c]			
NO_X (ozone season only)	121	$0.82 to $3.5	$0.82 to $3.5
Total Monetized Health Co-benefits		$12 to $28	$11 to $26
Total Monetized Health Co-benefits combined with Monetized Climate Benefits [d]		$32 to $48	$31 to $46

[a] All estimates are rounded to two significant figures, so estimates may not sum. It is important to note that the monetized co-benefits do not include reduced health effects from direct exposure to SO_2, direct exposure to NO_2, exposure to mercury, ecosystem effects or visibility impairment. Air pollution health co-benefits are estimated using regional benefit-per-ton estimates for the contiguous U.S.

[b] The monetized $PM_{2.5}$ co-benefits reflect the human health benefits associated with reducing exposure to $PM_{2.5}$ through reductions of $PM_{2.5}$ precursors, such as SO_2 and NO_X. The co-benefits do not include the benefits of reductions in directly emitted $PM_{2.5}$. These additional benefits would increase overall benefits by a few percent based on the analyses conducted for the proposed rule. PM co-benefits are shown as a range reflecting the use of two concentration-response functions, with the lower end of the range based on a function from Krewski et al. (2009) and the upper end based on a function from Lepeule et al. (2012). These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effect estimates by particle type.

[c] The monetized ozone co-benefits reflect the human health benefits associated with reducing exposure to ozone through reductions of NO_X during the ozone season. Ozone co-benefits are shown as a range reflecting the use of several different concentration-response functions, with the lower end of the range based on a function from Bell, et al. (2004) and the upper end based on a function from Levy, et al. (2005). Ozone co-benefits occur in the analysis year, so they are the same for all discount rates.

[d] We estimate climate benefits associated with four different values of a one ton CO_2 reduction (model average at 2.5 percent discount rate, 3 percent, and 5 percent; 95th percentile at 3 percent). Referred to as the social cost of carbon, each value increases over time. 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 carbon values. We provide combined climate and health estimates based on additional discount rates in the RIA.

The EPA has used the social cost of carbon (SC-CO_2) estimates presented in the *Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866 (May 2013, Revised June 2015)* (''current TSD'') to analyze CO_2 climate impacts of this rulemaking.[1051] We refer to these estimates, which were developed by the U.S. Government, as ''SC-CO_2 estimates.'' 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. It includes a wide range of anticipated climate impacts, such as net changes in agricultural productivity and human health, property damage from increased flood risk, and changes in energy system costs, such as reduced costs for heating and increased costs for air conditioning. It is typically used to assess the avoided damages as a result of regulatory actions (*i.e.,* benefits of rulemakings that lead to an incremental reduction in cumulative global CO_2 emissions).

The SC-CO_2 estimates used in this analysis were developed over many years, using the best science available, and with input from the public. Specifically, an interagency working group (IWG) that included the 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)[1052] provides a complete discussion of the methods used to develop these estimates and the current TSD presents and discusses the 2013 update (including two recent minor corrections to the estimates).[1053]

The EPA received numerous comments on the SC-CO_2 estimates as part of this rulemaking. The comments covered a wide range of topics including the technical details of the modeling conducted to develop the SC-CO_2 estimates, the aggregation and presentation of the SC-CO_2 estimates, and the process by which the SC-CO_2 estimates were derived. Many but not all commenters were supportive of the SC-CO_2 and its application to this rulemaking. Commenters also provided constructive recommendations for potential opportunities to improve the SC-CO_2 estimates in future updates. Many of these comments were similar to those that OMB's Office of Information and Regulatory Affairs received in response to a separate request for public comment on the approach used to develop the estimates. After careful evaluation of the full range of comments submitted to OMB, the IWG continues to recommend the use of the SC-CO_2 estimates in regulatory impact analysis.[1054] With the release of the response to comments, the IWG announced plans to obtain expert independent advice from the National Academies of Sciences, Engineering, and Medicine (Academies) to ensure that the SC-CO_2 estimates continue to reflect the best available scientific and economic information on climate change. The Academies review will be informed by the public comments received and focus on the technical merits and challenges of potential approaches to improving the SC-CO_2 estimates in future updates. See the EPA Response to Comments document for the complete response to comments received on SC-CO_2 as part of this rulemaking.

Concurrent with OMB's publication of the response to comments on SC-CO_2 and announcement of the Academies process, OMB posted a revised TSD that includes two minor technical corrections to the current estimates. One technical correction addressed an inadvertent omission of climate change damages in the last year of analysis (2300) in one model and the second addressed a minor indexing error in another model. On average the revised SC-CO_2 estimates are one dollar less than the mean SC-CO_2 estimates reported in the November 2013 revision to the May 2013 TSD. The change in the estimates associated with the 95th percentile estimates when using a 3 percent discount rate is slightly larger, as those estimates are heavily influenced by the results from the model that was affected by the indexing error.

The EPA, as a member of the IWG on the SC-CO_2, has carefully examined and evaluated the minor technical corrections in the revised TSD and the public comments submitted to OMB's separate SC-CO_2 comment process. Additionally, the EPA has carefully examined and evaluated all comments received regarding the SC-CO_2 through this rulemaking process. The EPA concurs with the IWG's conclusion that it is reasonable, and scientifically appropriate, to use the current SC-CO_2 estimates for purposes of regulatory impact analysis, including for this proceeding.

The four SC-CO_2 estimates are as follows: \$12, \$40, \$60, and \$120 per short ton of CO_2 emissions in the year 2020 (2011\$).[1055] The first three values are based on the average SC-CO_2 from the three IAMs, at discount rates of 5, 3, and 2.5 percent, respectively. The SC-CO_2 value at several discount rates are included because the literature shows that the SC-CO_2 is quite sensitive to assumptions about the discount rate, and because no consensus exists on the appropriate rate to use in an intergenerational context (where costs and benefits are incurred by different generations). The fourth value is the 95th percentile of the SC-CO_2 from all three models at a 3 percent discount

[1051] Docket ID EPA–HQ–OAR–2013–0495, Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866, Interagency Working Group on Social Cost of Carbon, with participation by Council of Economic Advisers, Council on Environmental Quality, Department of Agriculture, Department of Commerce, Department of Energy, Department of Transportation, Domestic Policy Council, Environmental Protection Agency, National Economic Council, Office of Management and Budget, Office of Science and Technology Policy, and Department of the Treasury (May 2013, Revised July 2015). Available at: *http://www.whitehouse.gov/sites/default/files/omb/inforeg/scc-tsd-final-july-2015.pdf.*

[1052] Docket ID EPA–HQ–OAR–2009–0472–114577, *Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866, Interagency Working Group on Social Cost of Carbon,* with participation by the Council of Economic Advisers, Council on Environmental Quality, Department of Agriculture, Department of Commerce, Department of Energy, Department of Transportation, Environmental Protection Agency, National Economic Council, Office of Energy and Climate Change, Office of Management and Budget, Office of Science and Technology Policy, and Department of Treasury (February 2010). Also available at: *http://www.whitehouse.gov/sites/default/files/omb/inforeg/for-agencies/Social-Cost-of-Carbon-for-RIA.pdf.*

[1053] The current version of the TSD is available at: *https://www.whitehouse.gov/sites/default/files/omb/inforeg/scc-response-to-comments-final-july-2015.pdf*, Docket ID EPA–HQ–OAR–2013–0495, *Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866,* Interagency Working Group on Social Cost of Carbon, with participation by Council of Economic Advisers, Council on Environmental Quality, Department of Agriculture, Department of Commerce, Department of Energy, Department of Transportation, Domestic Policy Council, Environmental Protection Agency, National Economic Council, Office of Management and Budget, Office of Science and Technology Policy, and Department of Treasury (May 2013, Revised July 2015).

[1054] See *https://www.whitehouse.gov/omb/oira/social-cost-of-carbon* for additional details, including the OMB Response to Comments and the SC-CO_2 TSDs.

[1055] The current version of the TSD is available at: *https://www.whitehouse.gov/sites/default/files/omb/inforeg/scc-tsd-final-july-2015.pdf.* The 2010 and 2013 TSDs present SC-CO_2 in 2007\$ per metric ton. The estimates were adjusted to (1) short tons for using conversion factor 0.90718474 and (2) 2011\$ using GDP Implicit Price Deflator, *http://www.gpo.gov/fdsys/pkg/ECONI-2013-02/pdf/ECONI-2013-02-Pg3.pdf.*

rate. It is included to represent higher-than-expected impacts from temperature change further out in the tails of the SC-CO_2 distribution (representing less likely, but potentially catastrophic, outcomes).

There are limitations in the estimates of the benefits from the final emission guidelines, including the omission of climate and other CO_2 related benefits that could not be monetized. The 2010 TSD discusses 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 impacts of CO_2 recognized in the literature, such as ocean acidification or potential tipping points, for various reasons, including the inherent difficulties in valuing non-market impacts and the fact that 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 emission reductions to inform the benefit-cost analysis. As previously noted, the IWG plans to seek independent expert advice on technical opportunities to improve the SC-CO_2 estimates from the Academies. The Academies process will help to ensure that the SC-CO_2 estimates used by the federal government continue to reflect the best available science and methodologies. Additional details are provided in the TSDs.

The health co-benefits estimates represent the total monetized human health benefits for populations exposed to reduced $PM_{2.5}$ and ozone resulting from emission reductions from the illustrative compliance strategy for the final standards. Unlike the global SC-CO_2 estimates, the air pollution health co-benefits are estimated for the contiguous U.S. only. We used a ''benefit-per-ton'' approach to estimate the benefits of this rulemaking. To create the $PM_{2.5}$ benefit-per-ton estimates, we conducted air quality modeling for an illustrative scenario reflecting the proposed standards to convert precursor emissions into changes in ambient $PM_{2.5}$ and ozone concentrations. We then used these air quality modeling results in BenMAP [1056] to calculate average regional benefit-per-ton estimates using the health impact assumptions used in the PM NAAQS RIA [1057] and Ozone NAAQS RIAs.[1058] [1059] The three regions were the Eastern U.S., Western U.S., and California. To calculate the co-benefits for the final standards, we multiplied the regional benefit-per-ton estimates generated from modeling of the proposed standards by the corresponding regional emission reductions for the final standards.[1060] All benefit-per-ton estimates reflect the geographic distribution of the modeled emissions for the proposed standards, which may not exactly match the emission reductions in this final rulemaking, and thus they may not reflect the local variability in population density, meteorology, exposure, baseline health incidence rates, or other local factors for any specific location. More information regarding the derivation of the benefit-per-ton estimates is available in the RIA.

PM benefit-per-ton values are generated using two concentration-response functions, Krewski et al. (2009) [1061] and Lepeule et al. (2012).[1062] These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effect estimates by particle type. Even though we assume that all fine particles have equivalent health effects, the benefit-per-ton estimates vary between $PM_{2.5}$ precursors depending on the location and magnitude of their impact on $PM_{2.5}$ concentrations, which drive population exposure.

It is important to note that the magnitude of the $PM_{2.5}$ and ozone co-benefits is largely driven by the concentration response functions for premature mortality and the value of a statistical life used to value reductions in premature mortality. For $PM_{2.5}$, we use two key empirical studies, one based on the American Cancer Society cohort study (Krewski et al., 2009) and one based on the extended Six Cities cohort study (Lepuele et al., 2012). We present the $PM_{2.5}$ co-benefits results as a range based on benefit-per-ton estimates calculated using the concentration-response functions from these two epidemiology studies, but this range does not capture the full range of uncertainty inherent in the co-benefits estimates. In the RIA for this rule, which is available in the docket, we also include $PM_{2.5}$ co-benefits estimates using benefit-per-ton estimates based on expert judgments of the effect of $PM_{2.5}$ on premature mortality (Roman et al., 2008) [1063] as a characterization of uncertainty regarding the $PM_{2.5}$-mortality relationship.

For the ozone co-benefits, we present the results as a range reflecting benefit-per-ton estimates which use several different concentration-response functions for mortality, with the lower end of the range based on a benefit-per-ton estimate using the function from Bell et al. (2004) [1064] and the upper end based on a benefit-per-ton estimate using the function from Levy et al. (2005).[1065] Similar to $PM_{2.5}$, the range of ozone co-benefits does not capture the full range of inherent uncertainty.

In this analysis, in estimating the benefits-per-ton for $PM_{2.5}$ precursors,

[1056] *http://www.epa.gov/airquality/benmap/index.html.*

[1057] U.S. Environmental Protection Agency (U.S. EPA). 2012. *Regulatory Impact Analysis for the Final Revisions to the National Ambient Air Quality Standards for Particulate Matter.* Research Triangle Park, NC: Office of Air Quality Planning and Standards, Health and Environmental Impacts Division. (EPA document number EPA–452/R–12–003, December). Available at: <*http://www.epa.gov/pm/2012/finalria.pdf*>.

[1058] U.S. Environmental Protection Agency (U.S. EPA). 2008b. Final Ozone NAAQS Regulatory Impact Analysis. Research Triangle Park, NC: Office of Air Quality Planning and Standards, Health and Environmental Impacts Division, Air Benefit and Cost Group Research. (EPA document number EPA–452/R–08–003, March). Available at: <*http://cfpub.epa.gov/ncea/cfm/recordisplay.cfm?deid=194645*>.

[1059] U.S. Environmental Protection Agency (U.S. EPA). 2010. Section 3: Re-analysis of the Benefits of Attaining Alternative Ozone Standards to Incorporate Current Methods. Available at: <*http://www.epa.gov/ttnecas1/regdata/RIAs/s3-supplemental_analysis-updated_benefits11-5.09.pdf*>.

[1060] U.S. Environmental Protection Agency. 2013. *Technical support document: Estimating the benefit per ton of reducing $PM_{2.5}$ precursors from 17 sectors.* Research Triangle Park, NC: Office of Air and Radiation, Office of Air Quality Planning and Standards, January. Available at: <*http://www.epa.gov/airquality/benmap/models/Source_Apportionment_BPT_TSD_1_31_13.pdf*>.

[1061] Krewski D.; M. Jerrett; R.T. Burnett; R. Ma; E. Hughes; Y. Shi, et al. 2009. *Extended Follow-up and Spatial Analysis of the American Cancer Society Study Linking Particulate Air Pollution and Mortality.* Health Effects Institute. (HEI Research Report number 140). Boston, MA: Health Effects Institute. Available at *http://www.healtheffects.org/Pubs/RR140-Krewski.pdf.*

[1062] Lepeule, J.; F. Laden; D. Dockery; J. Schwartz. 2012. ''Chronic Exposure to Fine Particles and Mortality: An Extended Follow-Up of the Harvard Six Cities Study from 1974 to 2009.'' *Environmental Health Perspective,* 120(7), July, pp. 965–970.

[1063] Roman, H., et al. 2008. ''Expert Judgment Assessment of the Mortality Impact of Changes in Ambient Fine Particulate Matter in the U.S.'' *Environmental Science & Technology,* Vol. 42, No. 7, February, pp. 2268–2274.

[1064] Bell, M.L., et al. 2004. ''Ozone and Short-Term Mortality in 95 U.S. Urban Communities, 1987–2000.'' *Journal of the American Medical Association,* 292(19), pp. 2372–8.

[1065] Levy, J.I., S.M. Chemerynski, and J.A. Sarnat. 2005. ''Ozone exposure and mortality: An empiric Bayes metaregression analysis.'' *Epidemiology.* 16(4): p. 458–68.

the EPA assumes that the health impact function for fine particles is without a threshold. This is based on the conclusions of EPA's *Integrated Science Assessment for Particulate Matter,*[1066] which evaluated the substantial body of published scientific literature, reflecting thousands of epidemiology, toxicology, and clinical studies that documents the association between elevated $PM_{2.5}$ concentrations and adverse health effects, including increased premature mortality. This assessment, which was twice reviewed by the EPA's independent Science Advisory Board, concluded that the scientific literature consistently finds that a no-threshold model most adequately portrays the PM-mortality concentration-response relationship.

In general, we are more confident in the magnitude of the risks we estimate from simulated $PM_{2.5}$ concentrations that coincide with the bulk of the observed PM concentrations in the epidemiological studies that are used to estimate the benefits. Likewise, we are less confident in the risk we estimate from simulated $PM_{2.5}$ concentrations that fall below the bulk of the observed data in these studies.

For this analysis, policy-specific air quality data are not available,[1067] and thus, we are unable to estimate the percentage of premature mortality associated with this specific rule that is above the lowest measured $PM_{2.5}$ levels (LML) for the two $PM_{2.5}$ mortality epidemiology studies that form the basis for our analysis. As a surrogate measure of mortality impacts above the LML, we provide the percentage of the population exposed above the lowest measured $PM_{2.5}$ level (LML) in each of the two studies, using the estimates of baseline projected $PM_{2.5}$ from the air quality modeling for the proposed guidelines used to calculate the benefit-per-ton estimates for the EGU sector. Using the Krewski et al. (2009) study, 88 percent of the population is exposed to annual mean $PM_{2.5}$ levels at or above the LML of 5.8 micrograms per cubic meter ($\mu g/m^3$). Using the Lepeule et al. (2012) study, 46 percent of the population is exposed above the LML of 8 $\mu g/m^3$. It is important to note that baseline exposure is only one parameter in the health impact function, along with baseline incidence rates, population, and change in air quality.

Every benefit analysis examining the potential effects of a change in environmental protection requirements is limited, to some extent, by data gaps, model capabilities (such as geographic coverage) and uncertainties in the underlying scientific and economic studies used to configure the benefit and cost models. Despite these uncertainties, we believe the air quality co-benefit analysis for this rule provides a reasonable indication of the expected health benefits of the air pollution emission reductions for the illustrative analysis of the final standards under a set of reasonable assumptions. This analysis does not include the type of detailed uncertainty assessment found in the 2012 $PM_{2.5}$ National Ambient Air Quality Standard (NAAQS) RIA (U.S. EPA, 2012) because we lack the necessary air quality input and monitoring data to conduct a complete benefits assessment. In addition, using a benefit-per-ton approach adds another important source of uncertainty to the benefits estimates. The 2012 $PM_{2.5}$ NAAQS benefits analysis provides an indication of the sensitivity of our results to various assumptions.

We note that the monetized co-benefits estimates shown here do not include several important benefit categories, including exposure to SO_2, NO_X, and hazardous air pollutants (*e.g.,* mercury and hydrogen chloride), as well as ecosystem effects and visibility impairment. Although we do not have sufficient information or modeling available to provide monetized estimates for this rule, we include a qualitative assessment of these unquantified benefits in the RIA for the final guidelines. In addition, in the RIA for the final standards, we did not estimate changes in emissions of directly emitted particles. As a result, quantified $PM_{2.5}$ related benefits are underestimated by a relatively small amount. In the RIA for the proposed guidelines, the benefits from reductions in directly emitted $PM_{2.5}$ were less than 10 percent of total monetized health co-benefits across all scenarios and years.

For more information on the benefits analysis, please refer to the RIA for this rule, which is available in the rulemaking docket.

XII. Statutory and Executive Order Reviews

Additional information about these Statutory 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 final 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. This analysis, which is contained in the ''Regulatory Impact Analysis for Clean Power Plan Final Rule'' (EPA–452/R–15–003, July 2015), is available in the docket and is briefly summarized in section XI of this preamble.

Consistent with Executive Order 12866 and Executive Order 13563, the EPA estimated the costs and benefits for illustrative compliance approaches of implementing the guidelines. The final rule establishes: (1) Carbon dioxide (CO_2) emission performance rates for two source categories of existing fossil fuel-fired EGUs, fossil fuel-fired electric utility steam generating units and stationary combustion turbines, and (2) guidelines for the development, submittal and implementation of state plans that implement the CO_2 emission performance rates. Actions taken to comply with the guidelines will also reduce the emissions of directly-emitted $PM_{2.5}$, SO_2 and NO_X. The benefits associated with these $PM_{2.5}$, SO_2 and NO_X reductions are referred to as co-benefits, as these reductions are not the primary objective of this rule.

The EPA has used the social cost of carbon estimates presented in the *Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866 (May 2013, Revised July 2015)* (''current TSD'') to analyze CO_2 climate impacts of this rulemaking. We refer to these estimates, which were developed by the U.S. government, as ''SC-CO_2 estimates.'' The SC-CO_2 is an estimate of the monetary value of impacts associated with a marginal change in CO_2 emissions in a given year. The four SC-CO_2 estimates are associated with different discount rates (model average at 2.5 percent discount rate, 3 percent, and 5 percent; 95th percentile at 3 percent), and each increases over time. In this summary, the EPA provides the estimate of climate benefits associated with the SC-CO_2 value deemed to be central in the current TSD: The model average at 3 percent discount rate.

In the final emission guidelines, the EPA has translated the source category-

[1066] U.S. Environmental Protection Agency. 2009. *Integrated Science Assessment for Particulate Matter (Final Report).* Research Triangle Park, NC: National Center for Environmental Assessment, RTP Division. (EPA document number EPA–600–R–08–139F, December). Available at: *http://cfpub.epa.gov/ncea/cfm/recordisplay.cfm?deid=216546.*

[1067] In addition, site-specific emission reductions will depend upon how states implement the guidelines.

specific CO_2 emission performance rates into equivalent state-level rate-based and mass-based CO_2 goals in order to maximize the range of choices that states will have in developing their plans. Because of the range of choices available to states and the lack of *a priori* knowledge about the specific choices states will make in response to the final goals, the Regulatory Impact Analysis (RIA) for this rule analyzed two implementation scenarios designed to achieve these goals, which we term the ''rate-based'' illustrative plan approach and the ''mass-based'' illustrative plan approach.

It is very important to note that the differences between the analytical results for the rate-based and mass-based illustrative plan approaches presented in the RIA may not be indicative of likely differences between the approaches if implemented by states and affected EGUs in response to the final guidelines. Rather, the two sets of analyses are intended to illustrate two different approaches to accomplish the emission performance rates finalized in the Clean Power Plan Final Rule. In other words, if one approach performs differently than the other on a given metric during a given time period, this does not imply this will apply in all instances in all time periods in all places.

The EPA estimates that, in 2020, the final guidelines will yield monetized climate benefits (in 2011$) of approximately $2.8 billion for the rate-based approach and $3.3 billion for the mass-based approach (3 percent model average). For the rate-based approach, the air pollution health co-benefits in 2020 are estimated to be $0.7 billion to $1.8 billion (2011$) for a 3 percent discount rate and $0.64 billion to $1.7 billion (2011$) for a 7 percent discount rate. For the mass-based approach, the air pollution health co-benefits in 2020 are estimated to be $2.0 billion to $4.8 billion (2011$) for a 3 percent discount rate and $1.8 billion to $4.4 billion (2011$) for a 7 percent discount rate. The annual, illustrative compliance costs estimated by IPM and inclusive of demand-side EE program and participant costs and MRR costs in 2020, are approximately $2.5 billion for the rate-based approach and $1.4 billion for the mass-based approach (2011$). The quantified net benefits (the difference between monetized benefits and compliance costs) in 2020 are estimated to range from $1.0 billion to $2.1 billion (2011$) for the rate-based approach and from $3.9 billion to 6.7 billion (2011$) for the mass-based approach, using a 3 percent discount rate (model average).

The EPA estimates that, in 2025, the final guidelines will yield monetized climate benefits (in 2011$) of approximately $10 billion for the rate-based approach and $12 billion for the mass-based approach (3 percent model average). For the rate-based approach, the air pollution health co-benefits in 2025 are estimated to be $7.4 billion to $18 billion (2011$) for a 3 percent discount rate and $6.7 billion to $16 billion (2011$) for a 7 percent discount rate. For the mass-based approach, the air pollution health co-benefits in 2025 are estimated to be $7.1 billion to $17 billion (2011$) for a 3 percent discount rate and $6.5 billion to $16 billion (2011$) for a 7 percent discount rate. The annual, illustrative compliance costs estimated by IPM and inclusive of demand-side EE program and participant costs and MRR costs in 2025, are approximately $1.0 billion for the rate-based approach and $3.0 billion for the mass-based approach (2011$). The quantified net benefits (the difference between monetized benefits and compliance costs) in 2025 are estimated to range from $17 billion to $27 billion (2011$) for the rate-based approach and $16 billion to $26 billion (2011$) for the mass-based approach, using a 3 percent discount rate (model average).

The EPA estimates that, in 2030, the final guidelines will yield monetized climate benefits (in 2011$) of approximately $20 billion for the rate-based approach and $20 billion for the mass-based approach (3 percent model average). For the rate-based approach, the air pollution health co-benefits in 2030 are estimated to be $14 billion to $34 billion (2011$) for a 3 percent discount rate and $13 billion to $31 billion (2011$) for a 7 percent discount rate. For the mass-based approach, the air pollution health co-benefits in 2030 are estimated to be $12 billion to $28 billion (2011$) for a 3 percent discount rate and $11 billion to $26 billion (2011$) for a 7 percent discount rate. The annual, illustrative compliance costs estimated by IPM and inclusive of demand-side EE program and participant costs and MRR costs in 2030, are approximately $8.4 billion for the rate-based approach and $5.1 billion for the mass-based approach (2011$). The quantified net benefits (the difference between monetized benefits and compliance costs) in 2030 are estimated to range from $26 billion to $45 billion (2011$) for the rate-based approach and from $26 billion to $43 billion (2011$) for the mass-based approach, using a 3 percent discount rate (model average).

Tables 20 and 21 provide the estimates of the climate benefits, health co-benefits, compliance costs and net benefits of the final emission guidelines for rate-based and mass-based illustrative plan approaches, respectively.

TABLE 21—SUMMARY OF THE MONETIZED BENEFITS, COMPLIANCE COSTS, AND NET BENEFITS FOR THE FINAL GUIDELINES IN 2020, 2025 AND 2030 UNDER THE RATE-BASED ILLUSTRATIVE PLAN APPROACH

[Billions of 2011$] [a]

<table>
<tr><th rowspan="2"></th><th colspan="6">Rate-based approach</th></tr>
<tr><th colspan="2">2020</th><th colspan="2">2025</th><th colspan="2">2030</th></tr>
<tr><td>Climate Benefits [b]</td><td colspan="2"></td><td colspan="2"></td><td colspan="2"></td></tr>
<tr><td>5% discount rate</td><td colspan="2">$0.80</td><td colspan="2">$3.1</td><td colspan="2">$6.4</td></tr>
<tr><td>3% discount rate</td><td colspan="2">$2.8</td><td colspan="2">$10</td><td colspan="2">$20</td></tr>
<tr><td>2.5% discount rate</td><td colspan="2">$4.1</td><td colspan="2">$15</td><td colspan="2">$29</td></tr>
<tr><td>95th percentile at 3% discount rate</td><td colspan="2">$8.2</td><td colspan="2">$31</td><td colspan="2">$61</td></tr>
<tr><td colspan="7">Air Quality Co-benefits Discount Rate</td></tr>
<tr><td></td><td>3%</td><td>7%</td><td>3%</td><td>7%</td><td>3%</td><td>7%</td></tr>
<tr><td>Air Quality Health Co-benefits [c]</td><td>$0.70 to $1.8</td><td>$0.64 to $1.7</td><td>$7.4 to $18</td><td>$6.7 to $16</td><td>$14 to $34</td><td>$13 to $31</td></tr>
<tr><td>Compliance Costs [d]</td><td colspan="2">$2.5</td><td colspan="2">$1.0</td><td colspan="2">$8.4</td></tr>
</table>

Net Benefits[e]	$1.0 to $2.1	$1.0 to $2.0	$17 to $27	$16 to $25	$26 to $45	$25 to $43
Non-Monetized Benefits	Non-monetized climate benefits. Reductions in exposure to ambient NO_2 and SO_2. Reductions in mercury deposition. Ecosystem benefits associated with reductions in emissions of NO_X, SO_2, PM, and mercury. Visibility impairment.					

[a] All are rounded to two significant figures, so figures may not sum.

[b] The climate benefit estimate in this summary table reflects global impacts from CO_2 emission changes and does not account for changes in non-CO_2 GHG emissions. Also, different discount rates are applied to SC-CO_2 than to the other estimates because CO_2 emissions are long-lived and subsequent damages occur over many years. The benefit estimates in this table are based on the average SC-CO_2 estimated for a 3 percent discount rate. However, we emphasize the importance and value of considering the full range of SC-CO_2 values. As shown in the RIA, climate benefits are also estimated using the other three SC-CO_2 estimates (model average at 2.5 percent discount rate, 3 percent, and 5 percent; 95th percentile at 3 percent). The SC-CO_2 estimates are year-specific and increase over time.

[c] The air pollution health co-benefits reflect reduced exposure to $PM_{2.5}$ and ozone associated with emission reductions of SO_2 and NO_X. The range reflects the use of concentration-response functions from different epidemiology studies. The co-benefits do not include the benefits of reductions in directly emitted $PM_{2.5}$. These additional benefits would increase overall benefits by a few percent based on the analyses conducted for the proposed rule. The reduction in premature fatalities each year accounts for over 98 percent of total monetized co-benefits from $PM_{2.5}$ and ozone. These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effect estimates by particle type.

[d] Total costs are approximated by the illustrative compliance costs estimated using the Integrated Planning Model for the final guidelines and a discount rate of approximately 5 percent. This estimate includes monitoring, recordkeeping, and reporting costs and demand-side EE program and participant costs.

[e] The estimates of net benefits in this summary table are calculated using the global SC-CO_2 at a 3 percent discount rate (model average). The RIA includes combined climate and health estimates based on additional discount rates.

TABLE 22—SUMMARY OF THE MONETIZED BENEFITS, COMPLIANCE COSTS, AND NET BENEFITS FOR THE FINAL GUIDELINES IN 2020, 2025 AND 2030 UNDER THE MASS-BASED ILLUSTRATIVE PLAN APPROACH

[Billions of 2011$][a]

	Mass-based approach		
	2020	2025	2030
Climate Benefits[b]			
5% discount rate	$0.9	$3.6	$6.4
3% discount rate	$3.3	$12	$20
2.5% discount rate	$4.9	$17	$29
95th percentile at 3% discount rate	$9.7	$35	$60

Air Quality Co-benefits Discount Rate

Air Quality Health Co-benefits[c]	3% $2.0 to $4.8	7% $1.8 to $4.4	3% $7.1 to $17	7% $6.5 to $16	3% $12 to $28	7% $11 to $26
Compliance Costs[d]	$1.4		$3.0		$5.1	
Net Benefits[e]	$3.9 to $6.7	$3.7 to $6.3	$16 to $26	$15 to $24	$26 to $43	$25 to $40
Non-Monetized Benefits	Non-monetized climate benefits. Reductions in exposure to ambient NO_2 and SO_2. Reductions in mercury deposition. Ecosystem benefits associated with reductions in emissions of NO_X, SO_2, PM, and mercury. Visibility improvement.					

[a] All are rounded to two significant figures, so figures may not sum.

[b] The climate benefit estimate in this summary table reflects global impacts from CO_2 emission changes and does not account for changes in non-CO_2 GHG emissions. Also, different discount rates are applied to SC-CO_2 than to the other estimates because CO_2 emissions are long-lived and subsequent damages occur over many years. The benefit estimates in this table are based on the average SC-CO_2 estimated for a 3 percent discount rate. However, we emphasize the importance and value of considering the full range of SC-CO_2 values. As shown in the RIA, climate benefits are also estimated using the other three SC-CO_2 estimates (model average at 2.5 percent discount rate, 3 percent, and 5 percent; 95th percentile at 3 percent). The SC-CO_2 estimates are year-specific and increase over time.

[c] The air pollution health co-benefits reflect reduced exposure to $PM_{2.5}$ and ozone associated with emission reductions of SO_2 and NO_X. The co-benefits do not include the benefits of reductions in directly emitted $PM_{2.5}$. These additional benefits would increase overall benefits by a few percent based on the analyses conducted for the proposed rule. The range reflects the use of concentration-response functions from different epidemiology studies. The reduction in premature fatalities each year accounts for over 98 percent of total monetized co-benefits from $PM_{2.5}$ and ozone. These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effect estimates by particle type.

[d] Total costs are approximated by the illustrative compliance costs estimated using the Integrated Planning Model for the final guidelines and a discount rate of approximately 5 percent. This estimate includes monitoring, recordkeeping, and reporting costs and demand-side EE program and participant costs.

[e] The estimates of net benefits in this summary table are calculated using the global SC-CO_2 at a 3 percent discount rate (model average). The RIA includes combined climate and health estimates based on additional discount rates.

There are additional important benefits that the EPA could not monetize. Due to current data and modeling limitations, our estimates of the benefits from reducing CO_2 emissions do not include important impacts like ocean acidification or potential tipping points in natural or managed ecosystems. Unquantified benefits also include climate benefits from reducing emissions of non-CO_2 GHGs (*e.g.,* nitrous oxide and methane) and co-benefits from reducing direct exposure to SO_2, NO_X and hazardous air pollutants (*e.g.,* mercury), as well as from reducing ecosystem effects and visibility impairment. Based upon the foregoing discussion, it remains clear that the benefits of this final action are substantial, and far exceed the costs. Additional details on benefits, costs, and net benefits estimates are provided in this RIA.

B. Paperwork Reduction Act (PRA)

The information collection requirements in this rule have been submitted for approval to OMB under the PRA. The Information Collection Request (ICR) document prepared by the EPA has been assigned the EPA ICR number 2503.02. You can find a copy of the ICR in the docket for this rule, and it is briefly summarized here. The information collection requirements are not enforceable until OMB approves them.

This rule does not directly impose specific requirements on EGUs located in states or areas of Indian country. The rule also does not impose specific requirements on tribal governments that have affected EGUs located in their area of Indian country. For areas of Indian country, the rule establishes CO_2 emission performance goals that could be addressed through either tribal or federal plans. A tribe would have the opportunity under the Tribal Authority Rule (TAR), but not the obligation, to apply to the EPA for Treatment as State (TAS) for purposes of a CAA section 111(d) plan and, if approved by the EPA, to establish a CAA section 111(d) plan for its area of Indian country. To date, no tribe has requested or obtained TAS eligibility for purposes of a CAA section 111(d) plan. For areas of Indian country with affected EGUs where a tribe has not applied for TAS and submitted any needed plan, if the EPA determines that a CAA section 111(d) plan is necessary or appropriate, the EPA would have the responsibility to establish the plans. Because tribes are not required to implement section 111(d) plans and because no tribe has yet sought TAS eligibility for this purpose, this action is not anticipated to impose any information collection burden on tribal governments over the 3-year period covered by this ICR.

This rule does impose specific requirements on state governments with affected EGUs. The information collection requirements are based on the recordkeeping and reporting burden associated with developing, implementing, and enforcing a plan to limit CO_2 emissions from existing sources in the utility power sector. 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.

The annual burden for this collection of information for the states (averaged over the first 3 years following promulgation) is estimated to be a range of 505,000 to 821,000 hours at a total annual labor cost of $35.8 to $58.1 million. The lower bound estimate reflects the assumption that some states already have EE and RE programs in place. The higher bound estimate reflects the overly-conservative assumption that no states have EE and RE programs in place.

The total annual burden for the federal government associated with the state collection of information (averaged over the first 3 years following promulgation) is estimated to be 54,000 hours at a total annual labor cost of $3.00 million. 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 OMB approves this ICR, the agency will announce that approval in the **Federal Register** and publish a technical amendment to 40 CFR part 9 to display the OMB control number for the approved information collection activities 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. This action will not impose any requirements on small entities. Specifically, emission guidelines established under CAA section 111(d) do not impose any requirements on regulated entities and, thus, will not have a significant economic impact upon a substantial number of small entities. After emission guidelines are promulgated, states establish emission standards on existing sources, and it is those requirements that could potentially impact small entities.

Our analysis here is consistent with the analysis of the analogous situation arising when the EPA establishes NAAQS, which do not impose any requirements on regulated entities. As here, any impact of a NAAQS on small entities would only arise when states take subsequent action to maintain and/or achieve the NAAQS through their SIPs. See *American Trucking Assoc.* v. *EPA,* 175 F.3d 1029, 1043–45 (D.C. Cir. 1999) (NAAQS do not have significant impacts upon small entities because NAAQS themselves impose no regulations upon small entities).

Nevertheless, the EPA is aware that there is substantial interest in the rule among small entities and, as detailed in section III.A of the preamble to the proposed carbon pollution emission guidelines for existing EGUs (79 FR 34845–34847; June 18, 2014) and in section II.D of the preamble to the proposed carbon pollution emission guidelines for existing EGUs in Indian Country and U.S. Territories (79 FR 65489; November 4, 2014), has conducted an unprecedented amount of stakeholder outreach. As part of that outreach, agency officials participated in many meetings with individual utilities and electric utility associations, as well as industry leaders and trade association representatives from various industries. While formulating the provisions of the rule, the EPA considered the input provided over the course of the stakeholder outreach as well as the input provided in the many public comments.

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. The emission guidelines do not impose any direct compliance requirements on EGUs located in states or areas of Indian country. As explained in section XII.B above, the rule also does not impose specific requirements on tribal governments that have affected EGUs located in their area of Indian country. The rule does impose specific requirements on state governments that have affected EGUs. Specifically, states are required to develop plans to implement the guidelines under CAA section 111(d) for affected EGUs. The burden for states to develop CAA section 111(d) plans in the 3-year period following promulgation of the rule was estimated and is listed in section XII.B above, but this burden is estimated to be below $100 million in any one year. Thus, this rule is not subject to the requirements of section 202 or section 205 of the UMRA.

This rule is also not subject to the requirements of section 203 of UMRA because it contains no regulatory requirements that might significantly or uniquely affect small governments. Specifically, the state governments to which rule requirements apply are not considered small governments.

In light of the interest among governmental entities, the EPA conducted outreach with national organizations representing state and local elected officials and tribal governmental entities while formulating the provisions of this rule. Sections III.A and XI.F of the preamble to the proposed carbon pollution emission guidelines for existing EGUs (79 FR 34845–34847; June 18, 2014) and sections II.D and VI.F of the preamble to the proposed carbon pollution emission guidelines for existing EGUs in areas of Indian Country and U.S. Territories (79 FR 65489; November 4, 2014) describes the extensive stakeholder outreach the EPA has conducted on setting emission guidelines for existing EGUs. The EPA considered the input provided over the course of the stakeholder outreach as well as the input provided in the many public comments when developing the provisions of these emission guidelines.

E. Executive Order 13132: Federalism

The EPA has concluded that this action may have federalism implications, pursuant to agency policy for implementing the Order, because it imposes substantial direct compliance costs on state or local governments, and the federal government will not provide the funds necessary to pay those costs. As discussed in the Supporting Statement found in the docket for this rulemaking, the development of state plans will entail many hours of staff time to develop and coordinate programs for compliance with the rule, as well as time to work with state legislatures as appropriate, to develop a plan submittal. Consistent with this determination, the EPA provides the following federalism summary impact statement.

The EPA consulted with state and local officials early in the process of developing the proposed action to permit them to have meaningful and timely input into its development. As described in the Federalism discussion in the preamble to the proposed standards of performance for GHG emissions from new EGUs (79 FR 1501; January 8, 2014), the EPA consulted with state and local officials in the process of developing the proposed standards for newly constructed EGUs. This outreach addressed planned actions for new, reconstructed, modified and existing sources. The EPA invited the following 10 national organizations representing state and local elected officials to a meeting on April 12, 2011, in Washington, DC: (1) National Governors Association; (2) National Conference of State Legislatures, (3) Council of State Governments, (4) National League of Cities, (5) U.S. Conference of Mayors, (6) National Association of Counties, (7) International City/County Management Association, (8) National Association of Towns and Townships, (9) County Executives of America, and (10) Environmental Council of States. The National Association of Clean Air Agencies also participated. On February 26, 2014, the EPA re-engaged with those governmental entities to provide a pre-proposal update on the emission guidelines for existing EGUs and emission standards for modified and reconstructed EGUs. In addition, as described in section III.A of the preamble to the proposed carbon pollution emission guidelines for existing EGUs (79 FR 34845–34847; June 18, 2014), extensive stakeholder outreach conducted by the EPA allowed state leaders, including governors, state attorneys general, environmental commissioners, energy officers, public utility commissioners, and air directors, opportunities to engage with EPA officials and provide input regarding reducing carbon pollution from power plants.

In the spirit of Executive Order 13132, and consistent with the EPA's policy to promote communications between the EPA and state and local governments, the EPA specifically solicited comment on the proposed action from state and local officials. The EPA received comments from over 400 entities representing state and local governments.

Several themes emerged from state and local government comments. Commenters raised concerns with the building blocks that comprise the best system of emission reduction (BSER), including the stringency of the building blocks, and the timing of achieving interim CO_2 levels. They also identified the potential for electric system reliability issues and stranded assets due to the proposed timeframe for plan submittals and CO_2 emission reductions. In addition, states commented on state plan development and implementation topics, including state plan approaches, early actions, trading programs, interstate crediting for RE, and EPA guidance and outreach.

Commenters identified overarching concerns regarding the stringency of the CO_2 goals and the timeframe for achieving reductions that encompassed the building blocks, the BSER, and associated timing for achievement of interim CO_2 levels. State commenters, in particular, identified changes to the stringency of the building blocks, concerns with the timeframe over which reductions must be achieved, and concerns with the approaches and measures used for the BSER. For the final rule, in response to stakeholder comments, the EPA has made refinements to the building blocks, the period of time over which measures are deployed, and the stringency of emission limitations that those measures can achieve in a practical and reasonable cost way. The final BSER reflects those refinements.

To many commenters, the proposal's 2020 compliance date, together with the stringency of the interim CO_2 goal, bore significant reliability implications. In this final rule, the agency is addressing those concerns via adjustments to the compliance timeframe (an 8-year interim period that begins in 2022) and to the approach for meeting interim CO_2 emission performance rates (a glide path separated into three steps, 2022–2024, 2025–2027, and 2028–2029), as well as a more gradual phase in of the emission reduction expectations. These adjustments provide more time for planning, consultation and decision making in the formulation of state plans and in EGUs' choices of compliance strategies. The final rule also retains flexibilities presented in the proposal and offers additional opportunities, including opportunities for trading within and between states, and other multi-state compliance approaches that will further support electric system reliability. The EPA is also requiring each state to demonstrate in its final state that it has considered electric system reliability issues in developing its plan—and is providing the time to do so. Even with this foundation of flexibility in place, these final guidelines further provide states with the option of proposing amendments to approved plans in the event that unanticipated and significant reliability challenges arise.

Commenters provided compelling information indicating that it will take longer than the agency initially anticipated to for states to complete the tasks necessary to finalize a state plan, including administrative and potential legislative processes. Recognizing this, as well as the urgent need for actions to reduce GHG emissions, the EPA is requiring states to make an initial submittal by September 6, 2016, and is allowing states two additional years to submit a final plan, if justified (to be submitted by September 6, 2018).

States commented on state plan development and implementation topics that included state plan approaches, early actions being taken into account, trading programs being allowed, interstate crediting for RE being allowed, and guidance and outreach being provided by the EPA. For the state plan approaches, commenters expressed concerns with the proposed ''portfolio approach'' for state plans, including concerns with enforceability of requirements, and identified a ''state commitment approach'' with backstop measures as an option for state plans. In this final rule, in response to stakeholder comments on the portfolio approach and alternative approaches, the EPA is finalizing a ''state measures'' approach that includes a requirement for the inclusion of backstop measures.

State commenters supported providing incentives for states and utilities to deploy CO_2-reducing investments, such as RE and demand-side EE measures, as early as possible. The EPA recognizes the value of such early actions, and in this final rule is establishing the CEIP to provide opportunities for investment in RE and demand-side EE projects that deliver results in 2020 and/or 2021.

Many state commenters supported the use of mass-based and rate-based emission trading programs in state plans, including interstate emission trading programs. The EPA also received a number of comments from states and stakeholders about the value of EPA support in developing and/or administering tracking systems to support state administration of rate-based and mass-based emission trading programs. In this final rule, states may use trading or averaging approaches and technologies or strategies that are not explicitly mentioned in any of the three building blocks as part of their overall plans, as long as they achieve the required emission reductions from affected fossil-fuel-fired EGUs. In addition, in response to concerns from states and power companies that the need for up-front interstate cooperation in developing multi-state plans could inhibit the development of interstate programs that could lower cost, the final rule provides additional options to allow individual EGUs to use creditable out-of-state reductions to achieve required CO_2 reductions, without the need for up-front interstate agreements. The EPA is committed to working with states to provide support for tracking of emissions and allowances or credits, to help implement multi-state trading or averaging approaches.

In their comments, many states identified the need for the EPA to provide guidance, including guidance on RE and EE emission measurement and verification (EM&V), and to maintain regular contact/forums with states throughout the implementation process. To provide state and local governments and other stakeholders with an understanding of the rule requirements, and to provide efficiencies where possible and reduce the cost and administrative burden, the EPA will continue outreach throughout the plan development and submittal process. Outreach will include opportunities for states to participate in briefings, teleconferences, and meetings about the final rule. The EPA's 10 regional offices will continue to be the entry point for states and tribes to ask technical and policy questions. The agency will host (or partner with appropriate groups to co-host) a number of webinars about various components of the final rule during the first two months after the final rule is issued. The EPA will use information from this outreach process to inform the training and other tools that will be of most use to the states and tribes that are implementing the final rule. The EPA expects to issue guidance on specific topics, including evaluation, measurement and verification (EM&V) for RE and demand-side EE, state-community engagement, and resources and financial assistance for RE and demand-side EE. As guidance documents, tools, templates and other resources become available, the EPA, in consultation with the U.S. Department of Energy and other federal agencies, will continue to make these resources available via a dedicated Web site.

A list of the state and local government commenters has been provided to OMB and has been placed in the docket for this rulemaking. In addition, the detailed response to comments from these entities is contained in the EPA's response to comments document on this final rulemaking, which has also been placed in the docket for this rulemaking.

As required by section 8(a) of Executive Order 13132, the EPA included a certification from its Federalism Official stating that the EPA had met the Executive Order's requirements in a meaningful and timely manner when it sent the draft of this final action to OMB for review pursuant to Executive Order 12866. A copy of the certification is included in the public version of the official record for this final action.

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. Tribes are not required to develop or adopt CAA programs, but they may apply to the EPA for treatment in a manner similar to states (TAS) and, if approved, do so. As a result, tribes are not required to develop plans to implement the guidelines under CAA section 111(d) for affected EGUs in their areas of Indian country. To the extent that a tribal government seeks and attains TAS status for that purpose, these emission guidelines would require that planning requirements be met and emission management implementation plans be executed by the tribes. The EPA notes that this rule does not directly impose specific requirements on affected EGUs, including those located in areas of Indian country, but provides guidance to any tribe approved by the EPA to address CO_2 emissions from EGUs subject to section 111(d) of the CAA. The EPA also notes that none of the affected EGUs are owned or operated by tribal governments.

As described in sections III.A and XI.F of the preamble to the proposed carbon pollution emission guidelines for existing EGUs (79 FR 34845–34847; June 18, 2014) and sections II.D and VI.F of the preamble to the proposed carbon pollution emission guidelines for existing EGUs in Indian Country and U.S. Territories (79 FR 65489; November 4, 2014), the rule was developed after extensive and vigorous outreach to tribal governments. These tribes expressed varied points of view. Some tribes raised concerns about the impacts of the regulations on EGUs located in their areas of Indian country and the subsequent impact on jobs and revenue for their tribes. Other tribes expressed concern about the impact the regulations would have on the cost of water covered under treaty to their communities as a result of increased costs to the EGU that provide energy to transport the water to the tribes. Other tribes raised concerns about the impacts of climate change on their communities, resources, ways of life and hunting and treaty rights. The tribes were also interested in the scope of the guidelines being considered by the agency (*e.g.,* over what time period, relationship to state and multi-state plans) and how tribes will participate in these planning activities.

The EPA consulted with tribal officials under the EPA Policy on Consultation and Coordination with Indian Tribes early in the process of developing this action to permit them to have meaningful and timely input into its development. A summary of that consultation follows.

Prior to issuing the supplemental proposal on November 4, 2014, the EPA consulted with tribes as follows. The EPA held a consultation with the Ute Tribe, the Crow Nation, and the Mandan, Hidatsa, Arikara (MHA) Nation on July 18, 2014. On August 22, 2014, the EPA held a consultation with the Fort Mojave Tribe. On September 15, 2014, the EPA held a consultation with the Navajo Nation. The Navajo Nation sent a letter to the EPA on September 18, 2014, summarizing the information presented at the consultation and the Navajo Nation's position on the supplemental proposal. One issue raised by tribal officials was the potential impacts of the June 18, 2014 proposal and the supplemental proposal on tribes with budgets that are dependent on revenue from coal mines and power plants, as well as employment at the mines and power plants. The tribes noted the high unemployment rates and lack of access to basic services on their lands. Tribal officials also asked whether the rules will have any impact on a tribe's ability to seek TAS. Tribal officials also expressed interest in agency actions with regard to facilitating power plant compliance with regulatory requirements. The Navajo Nation made the following recommendations in their letter of September 18, 2014: The Navajo Nation supports a mass-based CO_2 emission standard based on the highest historical CO_2 emissions since 1996; the Navajo Nation requests that the EPA grant the Navajo Nation carbon credits and that the Navajo Nation retains ownership and control of such credits; building block 2 is not appropriate for the Navajo Nation because there are no NGCC plants located on the Navajo Nation; building block 3 is not appropriate for the Navajo Nation because the Navajo people already receive virtually all of their electricity from carbon-free sources (mostly hydroelectric power) and their use of electricity is negligible compared to the generation at the power plants; building block 4 is not appropriate for the Navajo Nation because of the inadequate access to electricity, and the goal should allow for an increase in energy consumption on the Navajo Nation; the supplemental proposal should consider the useful life of the power plants located on the Navajo Nation; and the supplemental proposal should clarify that RE projects located within the Navajo Nation that provide electricity outside the Navajo Nation should be counted toward meeting the relevant state's RE goals under the Clean Power Plan.

After issuing the supplemental proposal, the EPA held additional consultation with tribes. On November 18, 2014, the EPA held consultations with the following tribes: Fort McDowell Yavapai Nation, Fort Mojave Tribe, Hopi Tribe, Navajo Nation, and Ak-Chin Indian Community. A consultation with the Ute Indian Tribe of the Uintah and Ouray Reservation was held on December 16, 2014 and with the Gila River Indian Community on January 15, 2015. The Navajo Nation reiterated the concerns raised during the previous consultation. Several tribes also again indicated that they wanted to ensure they would be included in the development of any tribal or federal plans for areas of Indian country. The Fort Mojave Tribe and the Navajo Nation expressed concern with using data from 2012 as the basis for the goal for their areas of Indian country; in their view, that year was not representative for the affected EGU. On April 28, 2015, the EPA held an additional consultation with the Navajo Nation. The issues raised by the Navajo Nation during the consultation included whether the EPA has the authority to set less stringent standards on a case-by-case basis, and a suggested ''parity glide path'' that would account and adjust for the very low electricity usage by the Navajo Nation and promote Navajo Nation economic growth and demand. Furthermore, on July 7, 2015 the EPA conducted an additional consultation with the Navajo Nation. One of the goals of the consultation was for the new government of the Navajo Nation to deepen their understanding of the rulemaking. The questions raised by the nation had to do with goal setting and carbon credits, the timing of the rulemaking, and the proposed federal plan. Additionally, on July 14, 2015 the EPA conducted an additional consultation with the Fort Mojave Tribe. The Fort Mojave tribes expressed concerns that 2012 is not a representative year, that natural gas-fired combined cycle power plants should be treated differently from coal-fired power plants, and that the proposed goal for Fort Mojave was not appropriate. Additionally, they also expressed interest in being engaged in the federal plan process. Responses to these comments and others received are available in the Response to Comment Document that is in the docket for this rulemaking. 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.

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.

CO_2 is a potent GHG that contributes to climate change and is emitted in significant quantities by fossil fuel-fired power plants. The EPA believes that the CO_2 emission reductions resulting from implementation of these final guidelines, as well as substantial ozone and $PM_{2.5}$ emission reductions as a co-benefit, will further improve children's health.

The assessment literature cited in the EPA's 2009 Endangerment Finding concluded that certain populations and lifestages, 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 II.A of this preamble.

H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

This action, which is a significant regulatory action under EO 12866, is likely to have a significant effect on the supply, distribution, or use of energy. The EPA has prepared a Statement of Energy Effects for this action as follows. We estimate a 1 to 2 percent change in retail electricity prices on average across the contiguous U.S. in 2025, and a 22 to 23 percent reduction in coal-fired electricity generation as a result of this rule. The EPA projects that utility power sector delivered natural gas prices will increase by up to 2.5 percent in 2030. For more information on the estimated energy effects, please refer to the economic impact analysis for this proposal. The analysis is available in the RIA, which is in the public docket.

I. National Technology Transfer and Advancement Act (NTTAA)

This rulemaking does not involve technical standards.

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

Executive Order 12898 (59 FR 7629; February 16, 1994) establishes federal executive policy on environmental justice. Its main provision directs federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations and low-income populations in the U.S. The EPA defines environmental justice as the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies. The EPA has this goal for all communities and persons across this Nation. It will be achieved when everyone enjoys the same degree of protection from environmental and health hazards and equal access to the decision-making process to have a healthy environment in which to live, learn, and work.

Leading up to this rulemaking the EPA summarized the public health and welfare effects of GHG emissions in its 2009 Endangerment Finding. See, section VIII.A of this preamble where the EPA summarizes the public health and welfare impacts from GHG emissions that were detailed in the 2009 Endangerment Finding under CAA section 202(a)(1).[1068] As part of the Endangerment Finding, the Administrator considered climate change risks to minority populations and low-income populations, finding that certain parts of the population may be especially vulnerable based on their characteristics or circumstances. Populations that were found to be particularly vulnerable to climate change risks include the poor, the elderly, the very young, those already in poor health, the disabled, those living alone, and/or indigenous populations dependent on one or a few resources. See sections XII.F and XII.G, above, where the EPA discusses Consultation and Coordination with Tribal Governments and Protection of Children. The Administrator placed weight on the fact that certain groups, including children, the elderly, and the poor, are most vulnerable to climate-related health effects.

The record for the 2009 Endangerment Finding summarizes the strong scientific evidence in the major assessment reports by the U.S. Global Change Research Program (USGCRP), the Intergovernmental Panel on Climate Change (IPCC), and the National Research Council (NRC) of the National Academies that the potential impacts of climate change raise environmental justice issues. These reports concluded that poor communities can be especially vulnerable to climate change impacts because they tend to have more limited adaptive capacities and are more dependent on climate-sensitive resources such as local water and food supplies. In addition, Native American tribal communities possess unique vulnerabilities to climate change, particularly those impacted by degradation of natural and cultural resources within established reservation boundaries and threats to traditional subsistence lifestyles. Tribal communities whose health, economic well-being, and cultural traditions that depend upon the natural environment will likely be affected by the degradation of ecosystem goods and services associated with climate change. The 2009 Endangerment Finding record also specifically noted that Southwest native cultures are especially vulnerable to water quality and availability impacts. Native Alaskan communities are already experiencing disruptive impacts, including coastal erosion and shifts in the range or abundance of wild species crucial to their livelihoods and well-being.

The most recent assessments continue to strengthen scientific understanding of climate change risks to minority populations and low-income populations in the U.S.[1069] The new assessment literature provides more detailed findings regarding these populations' vulnerabilities and projected impacts they may experience. In addition, the most recent assessment reports provide new information on how some communities of color (more specifically, populations defined jointly by ethnic/racial characteristics and geographic location) may be uniquely vulnerable to climate change health impacts in the U.S. These reports find that certain climate change related impacts—including heat waves, degraded air quality, and extreme weather events—have disproportionate effects on low-income populations and some communities of color, raising environmental justice concerns. Existing health disparities and other inequities in these communities increase their vulnerability to the health effects of climate change. In addition, assessment reports also find that climate change poses particular threats to health, well-being, and ways of life of indigenous peoples in the U.S.

As the scientific literature presented above and as the 2009 Endangerment Finding illustrates, low income populations and some communities of color are especially vulnerable to the health and other adverse impacts of climate change. The EPA believes that communities will benefit from this final rulemaking because this action directly addresses the impacts of climate change

[1068] ''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'').

[1069] 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, 841 pp.

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, 1132 pp. *https://www.ipcc.ch/report/ar5/wg2/.*

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, 688 pp. *https://www.ipcc.ch/report/ar5/wg2/.*

by limiting GHG emissions through the establishment of CO_2 emission guidelines for existing affected fossil fuel-fired EGUs.

In addition to reducing CO_2 emissions, the guidelines finalized in this rulemaking would reduce other emissions from affected EGUs that reduce generation due to higher adoption of EE and RE. These emission reductions will include SO_2 and NO_X, which form ambient $PM_{2.5}$ and ozone in the atmosphere, and HAP, such as mercury and hydrochloric acid. In the final rule revising the annual $PM_{2.5}$ NAAQS,[1070] the EPA identified low-income populations as being a vulnerable population for experiencing adverse health effects related to PM exposures. Low-income populations have been generally found to have a higher prevalence of pre-existing diseases, limited access to medical treatment, and increased nutritional deficiencies, which can increase this population's susceptibility to PM-related effects.[1071] In areas where this rulemaking reduces exposure to $PM_{2.5}$, ozone, and methylmercury, low-income populations will also benefit from such emissions reductions. The RIA for this rulemaking, included in the docket for this rulemaking, provides additional information regarding the health and ecosystem effects associated with these emission reductions.

Additionally, as outlined in the community and environmental justice considerations section IX of this preamble, the EPA has taken a number of actions to help ensure that this action will not have potential disproportionately high and adverse human health or environmental effects on overburdened communities. The EPA consulted its May 2015, *Guidance on Considering Environmental Justice During the Development of Regulatory Actions,* when determining what actions to take.[1072] As described in the community and environmental justice considerations section of this preamble the EPA also conducted a proximity analysis, which is available in the docket of this rulemaking and is discussed in section IX. Additionally, as outlined in sections I and IX of this preamble, the EPA has engaged with communities throughout this rulemaking and has devised a robust outreach strategy for continual engagement throughout the implementation phase of this rulemaking.

K. Congressional Review Act (CRA)

This final 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 a ''major rule'' as defined by 5 U.S.C. 804(2).

XIII. Statutory Authority

The statutory authority for this action is provided by sections 111, 301, 302, and 307(d)(1)(C) of the CAA as amended (42 U.S.C. 7411, 7601, 7602, 7607(d)(1)(C)). This action is also subject to section 307(d) of the CAA (42 U.S.C. 7607(d)).

List of Subjects in 40 CFR Part 60

Environmental protection, Administrative practice and procedure, Air pollution control, Intergovernmental relations, Reporting and recordkeeping requirements.

Dated: August 3, 2015.

Gina McCarthy,

Administrator.

For the reasons stated in the preamble, title 40, chapter I, part 60 of the Code of the Federal Regulations is 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. 7401 *et seq.*

■ 2. Add subpart UUUU to read as follows:

Subpart—UUUU Emission Guidelines for Greenhouse Gas Emissions and Compliance Times for Electric Utility Generating Units

Sec.

Introduction

60.5700 What is the purpose of this subpart?
60.5705 Which pollutants are regulated by this subpart?
60.5710 Am I affected by this subpart?
60.5715 What is the review and approval process for my State plan?
60.5720 What if I do not submit a plan or my plan is not approvable?
60.5725 In lieu of a State plan submittal, are there other acceptable option(s) for a State to meet its CAA section 111(d) obligations?
60.5730 Is there an approval process for a negative declaration letter?
60.5735 What authorities will not be delegated to State, local, or tribal agencies?
60.5736 Will the EPA impose any sanctions?
60.5737 What is the Clean Energy Incentive Program and how do I participate?

State and Multi-State Plan Requirements

60.5740 What must I include in my federally enforceable State or multi-State plan?
60.5745 What must I include in my final plan submittal?
60.5750 Can I work with other States to develop a multi-State plan?
60.5760 What are the timing requirements for submitting my plan?
60.5765 What must I include in an initial submittal if requesting an extension for a final plan submittal?
60.5770 What schedules, performance periods, and compliance periods must I include in my plan?
60.5775 What emission standards must I include in my plan?
60.5780 What State measures may I rely upon in support of my plan?
60.5785 What is the procedure for revising my plan?
60.5790 What must I do to meet my plan obligations?

Emission Rate Credit Requirements

60.5795 What affected EGUs qualify for generation of ERCs?
60.5800 What other resources qualify for issuance of ERCs?
60.5805 What is the process for the issuance of ERCs?
60.5810 What applicable requirements are there for an ERC tracking system?

Mass Allocations Requirements

60.5815 What are the requirements for State allocation of allowances in a mass-based program?
60.5820 What are my allowance tracking requirements?
60.5825 What is the process for affected EGUs to demonstrate compliance in a mass-based program?

Evaluation Measurement and Verification Plans and Monitoring and Verification Reports

60.5830 What are the requirements for EM&V plans for eligible resources?
60.5835 What are the requirements for M&V reports for eligible resources?

Applicability of Plans to Affected EGUs

60.5840 Does this subpart directly affect EGU owners and operators in my State?
60.5845 What affected EGUs must I address in my State plan?
60.5850 What EGUs are excluded from being affected EGUs?
60.5855 What are the CO_2 emission performance rates for affected EGUs?
60.5860 What applicable monitoring, recordkeeping, and reporting

[1070] ''National Ambient Air Quality Standards for Particulate Matter, Final Rule,'' 78 FR 3086 (Jan. 15, 2013).

[1071] U.S. Environmental Protection Agency (U.S. EPA). 2009. *Integrated Science Assessment for Particulate Matter (Final Report).* EPA–600–R–08–139F. National Center for Environmental Assessment—RTP Division. December. Available on the Internet at <*http://cfpub.epa.gov/ncea/cfm/recordisplay.cfm?deid=216546*>.

[1072] Guidance on Considering Environmental Justice During the Development of Regulatory Actions. *http://epa.gov/environmentaljustice/resources/policy/considering-ej-in-rulemaking-guide-final.pdf.* May 2015.

Introduction

§ 60.5700 What is the purpose of this subpart?

This subpart establishes emission guidelines and approval criteria for State or multi-State plans that establish emission standards limiting greenhouse gas (GHG) emissions from an affected steam generating unit, integrated gasification combined cycle (IGCC), or stationary combustion turbine. An affected steam generating unit, IGCC, or stationary combustion turbine shall, for the purposes of this subpart, be referred to as an affected EGU. These emission guidelines are developed in accordance with section 111(d) of the Clean Air Act and subpart B of this part. To the extent any requirement of this subpart is inconsistent with the requirements of subparts A or B of this part, the requirements of this subpart will apply.

§ 60.5705 Which pollutants are regulated by this subpart?

(a) The pollutants regulated by this subpart are greenhouse gases. The emission guidelines for greenhouse gases established in this subpart are expressed as carbon dioxide (CO_2) emission performance rates and equivalent statewide CO_2 emission goals.

(b) PSD and Title V Thresholds for Greenhouse Gases.

(1) For the purposes of § 51.166(b)(49)(ii), with respect to GHG emissions from facilities, the ''pollutant that is subject to the standard promulgated under section 111 of the Act'' shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in § 51.166(b)(48) and in any State Implementation Plan (SIP) approved by the EPA that is interpreted to incorporate, or specifically incorporates, § 51.166(b)(48) of this chapter.

(2) For the purposes of § 52.21(b)(50)(ii), with respect to GHG emissions from facilities regulated in the plan, the ''pollutant that is subject to the standard promulgated under section 111 of the Act'' shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in § 52.21(b)(49) of this chapter.

(3) For the purposes of § 70.2 of this chapter, with respect to greenhouse gas emissions from facilities regulated in the plan, the ''pollutant that is subject to any standard promulgated under section 111 of the Act'' shall be considered to be the pollutant that otherwise is ''subject to regulation'' as defined in § 70.2 of this chapter.

(4) For the purposes of § 71.2, with respect to greenhouse gas emissions from facilities regulated in the plan, the ''pollutant that is subject to any standard promulgated under section 111 of the Act'' shall be considered to be the pollutant that otherwise is ''subject to regulation'' as defined in § 71.2 of this chapter.

§ 60.5710 Am I affected by this subpart?

If you are the Governor of a State in the contiguous United States with one or more affected EGUs that commenced construction on or before January 8, 2014, you must submit a State or multi-State plan to the U.S. Environmental Protection Agency (EPA) that implements the emission guidelines contained in this subpart. If you are the Governor of a State in the contiguous United States with no affected EGUs for which construction commenced on or before January 8, 2014, in your State, you must submit a negative declaration letter in place of the State plan.

§ 60.5715 What is the review and approval process for my plan?

The EPA will review your plan according to § 60.27 except that under § 60.27(b) the Administrator will have 12 months after the date the final plan or plan revision (as allowed under § 60.5785) is submitted, to approve or disapprove such plan or revision or each portion thereof. If you submit an initial submittal under § 60.5765(a) in lieu of a final plan submittal the EPA will follow the procedure in § 60.5765(b).

§ 60.5720 What if I do not submit a plan or my plan is not approvable?

(a) If you do not submit an approvable plan the EPA will develop a Federal plan for your State according to § 60.27. The Federal plan will implement the emission guidelines contained in this subpart. Owners and operators of affected EGUs not covered by an approved plan must comply with a Federal plan implemented by the EPA for the State.

(b) After a Federal plan has been implemented in your State, it will be withdrawn when your State submits, and the EPA approves, a final plan.

§ 60.5725 In lieu of a State plan submittal, are there other acceptable option(s) for a State to meet its CAA section 111(d) obligations?

A State may meet its CAA section 111(d) obligations only by submitting a final State or multi-State plan submittal or a negative declaration letter (if applicable).

§ 60.5730 Is there an approval process for a negative declaration letter?

No. The EPA has no formal review process for negative declaration letters. Once your negative declaration letter has been received, the EPA will place a copy in the public docket and publish a notice in the **Federal Register**. If, at a later date, an affected EGU for which construction commenced on or before January 8, 2014 is found in your State, you will be found to have failed to submit a final plan as required, and a Federal plan implementing the emission guidelines contained in this subpart, when promulgated by the EPA, will apply to that affected EGU until you submit, and the EPA approves, a final State plan.

§ 60.5735 What authorities will not be delegated to State, local, or tribal agencies?

The authorities that will not be delegated to State, local, or tribal agencies are specified in paragraphs (a) and (b) of this section.

(a) Approval of alternatives, not already approved by this subpart, to the CO_2 emission performance rates in Table 1 to this subpart established under § 60.5855.

(b) Approval of alternatives, not already approved by this subpart, to the CO_2 emissions goals in Tables 2, 3 and 4 to this subpart established under § 60.5855.

§ 60.5736 Will the EPA impose any sanctions?

No. The EPA will not withhold any existing federal funds from a State on account of a State's failure to submit, implement, or enforce an approvable plan or plan revision, or to meet any other requirements under this subpart or subpart B of this part.

§ 60.5737 What is the Clean Energy Incentive Program and how do I participate?

(a) This subpart establishes the Clean Energy Incentive Program (CEIP). Participation in this program is optional. The program enables States to award early action emission rate credits (ERCs) and allowances to eligible renewable energy (RE) or demand-side energy efficiency (EE) projects that generate megawatt hours (MWh) or reduce end-use energy demand during 2020 and/or 2021. Eligible projects are those that:

(1) Are located in or benefit a state that has submitted a final state plan that includes requirements establishing its participation in the CEIP; and

(2) Commence construction in the case of RE, or commence operation in the case of demand-side EE, following the submission of a final state plan to the EPA, or after September 6, 2018 for a state that chooses not to submit a final state plan by that date; and either

(3) Generate metered MWh from any type of wind or solar resources; or

(4) Result in quantified and verified electricity savings (MWh) through demand-side EE implemented in low-income communities.

(b) The EPA will award matching ERCs or allowances to States that award early action ERCs or allowances, up to a match limit equivalent to 300 million tons of CO_2 emissions. The awards will be executed as follows:

(1) For RE projects that generate metered MWh from wind or solar resources: For every two MWh generated, the project will receive one early action ERC (or the equivalent number of allowances) from the State, and the EPA will provide one matching ERC (or the equivalent number of allowances) to the State to award to the project.

(2) For EE projects implemented in low-income communities: For every two MWh in end-use demand savings achieved, the project will receive two early action ERCs (or the equivalent number of allowances) from the State, and the EPA will provide two matching ERCs (or the equivalent number of allowances) to the State to award to the project.

(c) You may participate in this program by including in your State plan a mechanism that enables issuance of early action ERCs or allowances by the State to parties effectuating reductions in the calendar years 2020 and/or 2021 in a manner that would have no impact on the emission performance of affected EGUs required to meet rate-based or mass-based emission standards during the performance periods. This mechanism is not required to account for matching ERCs or allowances that may be issued to the State by the EPA.

(d) If you are submitting an initial submittal by September 6, 2016, and you intend to participate in the CEIP, you must include a non-binding statement of intent to participate in the program. If you are submitting a final plan by September 6, 2016, and you intend to participate in the CEIP, your State plan must either include requirements establishing the necessary infrastructure to implement such a program and authorizing your affected EGUs to use early action allowances or ERCs as appropriate, or you must include a non-binding statement of intent as part of your supporting documentation and revise your plan to include the appropriate requirements at a later date.

(e) If you intend to participate in the CEIP, your final State plan, or plan revision if applicable, must require that projects eligible under this program be evaluated, monitored, and verified, and that resulting ERCs or allowances be issued, per applicable requirements of the State plan approved by the EPA as meeting § 60.5805 through § 60.5835.

State and Multi-State Plan Requirements

§ 60.5740 What must I include in my federally enforceable State or multi State plan?

(a) You must include the components described in paragraphs (a)(1) through (5) of this section in your plan submittal. The final plan must meet the requirements and include the information required under § 60.5745.

(1) *Identification of affected EGUs.* Consistent with § 60.25(a), you must identify the affected EGUs covered by your plan and all affected EGUs in your State that meet the applicability criteria in § 60.5845. In addition, you must include an inventory of CO_2 emissions from the affected EGUs during the most recent calendar year for which data is available prior to the submission of the plan.

(2) *Emission standards.* You must include an identification of all emission standards for each affected EGU according to § 60.5775, compliance periods for each emission standard according to § 60.5770, and a demonstration that the emission standards, when taken together, achieve the applicable CO_2 emission performance rates or CO_2 emission goals described in § 60.5855. Allowance systems are an acceptable form of emission standards under this subpart.

(i) Your plan does not need to include corrective measures specified in paragraph (a)(2)(ii) of this section if your plan:

(A) Imposes emission standards on all affected EGUs that, assuming full compliance by all affected EGUs, mathematically assure achievement of the CO_2 emission performance rates in the plan for each plan period;

(B) Imposes emission standards on all affected EGUS that, assuming full compliance by all affected EGUs, mathematically assure achievement of the CO_2 emission goals; or

(C) Imposes emission standards on all affected EGUs that, assuming full compliance by all affected EGUs, in conjunction with applicable requirements under state law for EGUs subject to subpart TTTT of this subpart, assuming the applicable requirements under state law are met by all EGUs subject to subpart TTTT of this subpart, achieve the applicable mass-based CO_2 emission goals plus new source CO_2 emission complement allowed for in § 60.5790(b)(5).

(ii) If your plan does not meet the requirements of (a)(2)(i) or (iii) of this section, your plan must include the requirement for corrective measures to be implemented if triggered. Upon triggering corrective measures, if you do not already have them included in your approved State plan, you must submit corrective measures to EPA for approval as a plan revision per the requirements of § 60.5785(c). These corrective measures must ensure that the interim period and final period CO_2 emission performance rates or CO_2 emission goals are achieved by your affected EGUs, as applicable, and must achieve additional emission reductions to offset any emission performance shortfall. Your plan must include the requirement that corrective measures be triggered and implemented according to paragraphs (a)(2)(ii)(A) through (H) of this section.

(A) Your plan must include a trigger for an exceedance of an interim step 1 or interim step 2 CO_2 emission performance rate or CO_2 emission goal by 10 percent or greater, either on average or cumulatively (if applicable).

(B) Your plan must include a trigger for an exceedance of an interim step 1 goal or interim step 2 goal of 10 percent or greater based on either reported CO_2 emissions with applied plus or minus net allowance export or import adjustments (if applicable), or based on the adjusted CO_2 emission rate (if applicable).

(C) Your plan must include a trigger for a failure to meet an interim period goal based on reported CO_2 emissions with applied plus or minus net allowance export or import adjustments (if applicable), or based on the adjusted CO_2 emission rate (if applicable).

(D) Your plan must include a trigger for a failure to meet the interim period or any final reporting period CO_2 emission performance rate or CO_2 emission goal, either on average or cumulatively (as applicable).

(E) Your plan must include a trigger for a failure to meet any final reporting period goal based on reported CO_2 emissions with applied plus or minus net allowance export or import adjustments (if applicable).

(F) Your plan must include a trigger for a failure to meet the interim period CO_2 emission performance rate or CO_2 emission goal based on the adjusted CO_2 emission rate (if applicable).

(G) Your plan must include a trigger for a failure to meet any final reporting period CO_2 emission performance rate or CO_2 emission goal based on the adjusted CO_2 emission rate (if applicable).

(H) A net allowance import adjustment represents the CO_2 emissions (in tons) equal to the number of net imported CO_2 allowances. This adjustment is subtracted from reported CO_2 emissions. Under this adjustment, such allowances must be issued by a state with an emission budget trading program that only applies to affected EGUs (or affected EGUs plus EGUs covered by subpart TTTT of this part as applicable). A net allowance export adjustment represents the CO_2 emissions (in tons) equal to the number of net exported CO_2 allowances. This adjustment is added to reported CO_2 emissions.

(iii) If your plan relies upon State measures, in addition to or in lieu of emission standards on your affected EGUs, then the final State plan must include the requirements in paragraph (a)(3) of this section and the submittal must include the information listed in § 60.5745(a)(6).

(iv) If your plan requires emission standards in addition to relying upon State measures, then you must demonstrate that the emission standards and State measures, when taken together, result in the achievement of the applicable mass-based CO_2 emission goal described in § 60.5855 by your State's affected EGUs.

(3) *State measures backstop.* If your plan relies upon State measures, you must submit, as part of the plan in lieu of the requirements in paragraph (a)(2)(i) and (ii) of this section, a federally enforceable backstop that includes emission standards for affected EGUs that will be put into place, if there is a triggering event listed in paragraph (a)(3)(i) of this section, within 18 months of the due date of the report required in § 60.5870(b). The emission standards on the affected EGUs as part of the backstop must be able to meet either the CO_2 emission performance rates or mass-based or rate-based CO_2 emission goal for your State during the interim and final periods. You must either submit, along with the backstop emission standards, provisions to adjust the emission standards to make up for the prior emission performance shortfall, such that no later plan revision to modify the emission standards is necessary in order to address the emission performance shortfall, or you must submit, as part of the final plan, backstop emission standards that assure affected EGUs would achieve your State's CO_2 emission performance rates or emission goals during the interim and final periods, and then later submit appropriate revisions to the backstop emission standards adjusting for the shortfall through the State plan revision process described in § 60.5785. The backstop must also include the requirements in paragraphs (a)(3)(i) through (iii) of this section, as applicable.

(i) You must include a trigger for the backstop to go into effect upon:

(A) A failure to meet a programmatic milestone;

(B) An exceedance of 10 percent or greater of an interim step 1 goal or interim step 2 goal based on reported CO_2 emissions, with applied plus or minus net allowance export or import adjustments (if applicable);

(C) A failure to meet the interim period goal based on reported CO_2 emissions, with applied plus or minus net allowance export or import adjustments (if applicable); or

(D) A failure to meet any final reporting period goal based on reported CO_2 emissions, with applied plus or minus net allowance export or import adjustments (if applicable).

(ii) You may include in your plan any additional triggers so long as they do not reduce the stringency of the triggers required under paragraph (a)(3)(i) of this section.

(iii) You must include a schedule for implementation of the backstop once triggered, and you must identify all necessary State administrative and technical procedures for implementing the backstop.

(4) *Identification of applicable monitoring, reporting, and recordkeeping requirements for each affected EGU.* You must include in your plan all applicable monitoring, reporting and recordkeeping requirements for each affected EGU and the requirements must be consistent with or no less stringent than the requirements specified in § 60.5860.

(5) *State reporting.* You must include in your plan a description of the process, contents, and schedule for State reporting to the EPA about plan implementation and progress, including information required under § 60.5870.

(i) You must include in your plan a requirement for a report to be submitted by July 1, 2021, that demonstrates that the State has met, or is on track to meet, the programmatic milestone steps indicated in the timeline required in § 60.5770.

(b) You must follow the requirements of subpart B of this part and demonstrate that they were met in your State plan. However, the provisions of § 60.24(f) shall not apply.

§ 60.5745 What must I include in my final plan submittal?

(a) In addition to the components of the plan listed in § 60.5740, a final plan submittal to the EPA must include the information in paragraphs (a)(1) through (13) of this section. This information must be submitted to the EPA as part of your final plan submittal but will not be codified as part of the federally enforceable plan upon approval by EPA.

(1) You must include a description of your plan approach and the geographic scope of the plan (*i.e.,* State or multi-State, geographic boundaries related to the plan elements), including, if applicable, identification of multi-State plan participants.

(2) You must identify CO_2 emission performance rates or equivalent statewide CO_2 emission goals that your affected EGUs will achieve. If the geographic scope of your plan is a single State, then you must identify CO_2 emission performance rates or emission goals according to § 60.5855. If your plan includes multiple States and you elect to set CO_2 emission goals, you must identify CO_2 emission goals calculated according to § 60.5750.

(i) You must specify in the plan submittal the CO_2 emission performance rates or emission goals that affected EGUs will meet for the interim period, each interim step, and the final period (including each final reporting period) pursuant to § 60.5770.

(ii) [Reserved]

(3) You must include a demonstration that the affected EGUs covered by the plan are projected to achieve the CO_2 emission performance rates or CO_2 emission goals described in § 60.5855.

(4) You must include a demonstration that each affected EGU's emission standard is quantifiable, non-

duplicative, permanent, verifiable, and enforceable according to § 60.5775.

(5) If your plan includes emission standards on your affected EGUs sufficient to meet either the CO_2 emission performance rates or CO_2 emission goals, you must include in your plan submittal the information in paragraphs (a)(5)(i) through (v) of this section as applicable.

(i) If your plan applies separate rate-based CO_2 emission standards for affected EGUs (in lbs CO_2/MWh) that are equal to or lower than the CO_2 emission performance rates listed in Table 1 of this subpart or uniform rate-based CO_2 emission standards equal to or lower than the rate-based CO_2 emission goals listed in Table 2 of this subpart, then no additional demonstration is required beyond inclusion of the emission standards in the plan.

(ii) If a plan applies rate-based emission standards to individual affected EGUs at a lbs CO_2/MWh rate that differs from the CO_2 emission performance rates in Table 1 of this subpart or the State's rate-based CO_2 emission goal in Table 2 of this subpart, then a further demonstration is required that the application of the CO_2 emission standards will achieve the CO_2 emission performance rates or State rate-based CO_2 emission goal. You must demonstrate through a projection that the adjusted weighted average CO_2 emission rate of affected EGUs, when weighted by generation (in MWh), will be equal to or less than the CO_2 emission performance rates or the rate-based CO_2 emission goal. This projection must address the interim period and the final period. The projection in the plan submittal must include the information listed in paragraph (a)(5)(v) of this section and in addition the following:

(A) An analysis of the change in generation of affected EGUs given the compliance costs and incentives under the application of different emission rate standards across affected EGUs in a State;

(B) A projection showing how generation is expected to shift between affected EGUs and across affected EGUs and non-affected EGUs over time;

(C) Assumptions regarding the availability and anticipated use of the MWh of electricity generation or electricity savings from eligible resources that can be issued ERCs;

(D) The specific calculation (or assumption) of how eligible resource MWh of electricity generation or savings are being used in the projection to adjust the reported CO_2 emission rate of affected EGUs;

(E) If a state plan provides for the ability of renewable energy resources located in states with mass-based plans to be issued ERCs, consideration in the projection that such resources must meet geographic eligibility requirements, consistent with § 60.5800(a); and

(F) Any other applicable assumptions used in the projection.

(iii) If a plan establishes mass-based emission standards for affected EGUs that cumulatively do not exceed the State's EPA-specified mass CO_2 emission goal, then no additional demonstration is required beyond inclusion of the emission standards in the plan.

(iv) If a plan applies mass-based emission standards to individual affected EGUs that cumulatively exceed the State's EPA-specified mass CO_2 emission goal, then you must include a demonstration that your mass-based emission program will be designed such that compliance by affected EGUs would achieve the State mass-based CO_2 emission goals. This demonstration includes the information listed in paragraph (a)(5)(v) of this section.

(v) Your plan demonstration to be included in your plan submittal, if applicable, must include the information listed in paragraphs (a)(5)(v)(A) through (L) of this section.

(A) A summary of each affected EGU's anticipated future operation characteristics, including:

(*1*) Annual generation;

(*2*) CO_2 emissions;

(*3*) Fuel use, fuel prices (when applicable), fuel carbon content;

(*4*) Fixed and variable operations and maintenance costs (when applicable);

(*5*) Heat rates; and

(*6*) Electric generation capacity and capacity factors.

(B) An identification of any planned new electric generating capacity.

(C) Analytic treatment of the potential for building unplanned new electric generating capacity.

(D) A timeline for implementation of EGU-specific actions (if applicable).

(E) All wholesale electricity prices.

(F) A geographic representation appropriate for capturing impacts and/or changes in the electric system.

(G) A time period of analysis, which must extend through at least 2031.

(H) An anticipated electricity demand forecast (MWh load and MW peak demand) at the State and regional level, including the source and basis for these estimates, and, if appropriate, justification and documentation of underlying assumptions that inform the development of the demand forecast (*e.g.,* annual economic and demand growth rate or population growth rate).

(I) A demonstration that each emission standard included in your plan meets the requirements of § 60.5775.

(J) Any ERC or emission allowance prices, when applicable.

(K) An identification of planning reserve margins.

(L) Any other applicable assumptions used in the projection.

(6) If your plan relies upon State measures, in addition to or in lieu of the emission standards required by paragraph § 60.5740(a)(2), the final State plan submittal must include the information under paragraphs (a)(5)(v) and (a)(6)(i) through (v) of this section.

(i) You must include a description of all the State measures the State will rely upon to achieve the applicable CO_2 emission goals required under § 60.5855(e), the projected impacts of the State measures over time, the applicable State laws or regulations related to such measures, and identification of parties or entities subject to or implementing such State measures.

(ii) You must include the schedule and milestones for the implementation of the State measures. If the State measures in your plan submittal rely upon measures that do not have a direct effect on the CO_2 emissions measured at an affected EGU's stack, you must also demonstrate how the minimum emission, monitoring and verification (EM&V) requirements listed under § 60.5795 that apply to those programs and projects will be met.

(iii) You must demonstrate that federally enforceable emission standards for affected EGUs in conjunction with any State measures relied upon for your plan, are sufficient to achieve the mass-based CO_2 emission goal for the interim period, each interim step in that interim period, the final period, and each final reporting period. In addition, you must demonstrate that each emission standard included in your plan meets the requirements of § 60.5775 and each State measure included in your plan submittal meets the requirements of § 60.5780.

(iv) You must include a CO_2 performance projection of your State measures that shows how the measures, whether alone or in conjunction with any federally enforceable CO_2 emission standards for affected EGUs, will result in the achievement of the future CO_2 performance at affected EGUs. Elements of this projection must include those specified in paragraph (a)(5)(v) of this section, as applicable, and the following for the interim period and the final period:

(A) A baseline demand and supply forecast as well as the underlying assumptions and data sources of each forecast;

(B) The magnitude of energy and emission impacts from all measures included in the plan and applicable assumptions;

(C) An identification of State-enforceable measures with electricity savings and RE generation, in MWh, expected for individual and collective measures and any assumptions related to the quantification of the MWh, as applicable.

(7) Your plan submittal must include a demonstration that the reliability of the electrical grid has been considered in the development of your plan.

(8) Your plan submittal must include a timeline with all the programmatic milestone steps the State intends to take between the time of the State plan submittal and January 1, 2022 to ensure the plan is effective as of January 1, 2022.

(9) Your plan submittal must adequately demonstrate that your State has the legal authority (*e.g.,* through regulations or legislation) and funding to implement and enforce each component of the State plan submittal, including federally enforceable emission standards for affected EGUs, and State measures as applicable.

(10) Your State plan submittal must demonstrate that each interim step goal required under § 60.5855(c), will be met and include in its supporting documentation, if applicable, a description of the analytic process, tools, methods, and assumptions used to make this demonstration.

(11) Your plan submittal must include certification that a hearing required under § 60.23(c)(1) on the State plan was held, a list of witnesses and their organizational affiliations, if any, appearing at the hearing, and a brief written summary of each presentation or written submission, pursuant to the requirements of § 60.23(d) and (f).

(12) Your plan submittal must include documentation of any conducted community outreach and community involvement, including engagement with vulnerable communities.

(13) Your plan submittal must include supporting material for your plan including:

(i) Materials demonstrating the State's legal authority and funding to implement and enforce each component of its plan, including emissions standards and/or State measures that the plan relies upon;

(ii) Materials supporting that the CO_2 emission performance rates or CO_2 emission goals will be achieved by affected EGUs identified under the plan, according to paragraph (a)(3) of this section;

(iii) Materials supporting any calculations for CO_2 emission goals calculated according to § 60.5855, if applicable; and

(iv) Any other materials necessary to support evaluation of the plan by the EPA.

(b) You must submit your final plan to the EPA electronically according to § 60.5875.

§ 60.5750 Can I work with other States to develop a multi-State plan?

A multi-State plan must include all the required elements for a plan specified in § 60.5740(a). A multi-State plan must meet the requirements of paragraphs (a) and (b) of this section.

(a) The multi-State plan must demonstrate that all affected EGUs in all participating States will meet the CO_2 emission performance rates listed in Table 1 of this subpart or an equivalent CO_2 emission goal according to paragraphs (a)(1) or (2) of this section. States may only follow the procedures in (a)(1) or (2) if they have functionally equivalent requirements meeting § 60.5775 and § 60.5790 included in their plans.

(1) For States electing to demonstrate performance with a CO_2 emission rate-based goal, the CO_2 emission goals identified in the plan according to § 60.5855 will be an adjusted weighted (by net energy output) average lbs CO_2/MWh emission rate to be achieved by all affected EGUs in the multi-State area during the plan periods; or

(2) For States electing to demonstrate performance with a CO_2 emission mass-based goal, the CO_2 emission goals identified in the multi-State plan according to § 60.5855 will be total mass CO_2 emissions by all affected EGUs in the multi-State area during the plan periods, representing the sum of all individual mass CO_2 goals for states participating in the multi-state plan.

(b) Options for submitting a multi-State plan include the following:

(1) States participating in a multi-State plan may submit one multi-State plan submittal on behalf of all participating States. The joint submittal must be signed electronically, according to § 60.5875, by authorized officials for each of the States participating in the multi-State plan. In this instance, the joint submittal will have the same legal effect as an individual submittal for each participating State. The joint submittal must address plan components that apply jointly for all participating States and components that apply for each individual State in the multi-State plan, including necessary State legal authority to implement the plan, such as State regulations and statutes.

(2) States participating in a multi-State plan may submit a single plan submittal, signed by authorized officials from each participating State, which addresses common plan elements. Each participating State must, in addition, provide individual plan submittals that address State-specific elements of the multi-State plan.

(3) States participating in a multi-State plan may separately make individual submittals that address all elements of the multi-State plan. The plan submittals must be materially consistent for all common plan elements that apply to all participating States, and also must address individual State-specific aspects of the multi-State plan. Each individual State plan submittal must address all required plan components in § 60.5740.

(c) A State may elect to participate in more than one multi-State plan. If your State elects to participate in more than one multi-State plan then you must identify in the State plan submittal required under § 60.5745, the subset of affected EGUs that are subject to the specific multi-State plan or your State's individual plan. An affected EGU can only be subject to one plan.

(d) A State may elect to allow its affected EGUs to interact with affected EGUs in other States through mass-based trading programs or a rate-based trading program without entering into a formal multi-State plan allowed for under this section, so long as such programs are part of an EPA-approved state plan and meet the requirements of paragraphs (d)(1) and (2) of this section, as applicable.

(1) For States that elect to do mass-based trading under this option the State must indicate in its plan that its emission budget trading program will be administered using an EPA-approved (or EPA-administered) emission and allowance tracking system.

(2) For States that elect to use a rate-based trading program which allows the affected EGUs to use ERCs from other State rate-based trading programs, the plan must require affected EGUs within their State to comply with emission standards equal to the sub-category CO_2 emission performance rates in Table 1 of this subpart.

§ 60.5760 What are the timing requirements for submitting my plan?

(a) You must submit a final plan with the information required under § 60.5745 by September 6, 2016, unless you are submitting an initial submittal, allowed under § 60.5765, in lieu of a final State plan submittal, according to paragraph (b) of this section.

(b) For States seeking a two year extension for a final plan submittal, you must include the information in § 60.5765(a) in an initial submittal by September 6, 2016, to receive an extension to submit your final State plan submittal by September 6, 2018.

(c) You must submit all information required under paragraphs (a) and (b) of this section according to the electronic reporting requirements in § 60.5875.

§ 60.5765 What must I include in an initial submittal if requesting an extension for a final plan submittal?

(a) You must sufficiently demonstrate that your State is able to undertake steps and processes necessary to timely submit a final plan by the extended date of September 6, 2018, by addressing the following required components in an initial submittal by September 6, 2016, if requesting an extension for a final plan submittal:

(1) An identification of final plan approach or approaches under consideration and a description of progress made to date on the final plan components;

(2) An appropriate explanation of why the State requires additional time to submit a final plan by September 6, 2018; and

(3) A demonstration or description of the opportunity for public comment on the initial submittal and meaningful engagement with stakeholders, including vulnerable communities, during the time in preparation of the initial submittal and the plans for engagement during development of the final plan.

(b) You must submit an initial submittal allowed in paragraph (a) of this section, information required under paragraph (c) of this section (only if a State elects to submit an initial submittal to request an extension for a final plan submittal), and a final State plan submittal according to § 60.5870. If a State submits an initial submittal, an extension for a final State plan submittal is considered granted and a final State plan submittal is due according to § 60.5760(b) unless a State is notified within 90 days of the EPA receiving the initial submittal that the EPA finds the initial submittal does not meet the requirements listed in paragraph (a) of this section. If the EPA notifies the State that the initial submittal does not meet such requirements, the EPA will also notify the State that it has failed to submit the final plan required by September 6, 2016.

(c) If an extension for submission of a final plan has been granted, you must submit a progress report by September 6, 2017. The 2017 report must include the following:

(1) A summary of the status of each component of the final plan, including an update from the 2016 initial submittal and a list of which final plan components are not complete.

(2) A commitment to a plan approach (*e.g.,* single or multi-State, rate-based or mass-based emission performance level, rate-based or mass-based emission standards), including draft or proposed legislation and/or regulations.

(3) An updated comprehensive roadmap with a schedule and milestones for completing the final plan, including any updates to community engagement undertaken and planned.

§ 60.5770 What schedules, performance periods, and compliance periods must I include in my plan?

(a) The affected EGUs covered by your plan must meet the CO_2 emission requirements required under § 60.5855 for the interim period, interim steps, and the final reporting periods according to paragraph (b) of this section. You must also include in your plan compliance periods for each affected EGU regulated under the plan according to paragraphs (c) and (d) of this section.

(b) Your plan must require your affected EGUs to achieve each CO_2 emission performance rate or CO_2 emission goal, as applicable, required under § 60.5855 over the periods according to paragraphs (b)(1) through (3) of this section.

(1) The interim period.

(2) Each interim step.

(3) Each final reporting period.

(c) The emission standards for affected EGUs regulated under the plan must include the following compliance periods:

(1) For the interim period, affected EGUs must have emission standards that have compliance periods that are no longer than each interim step and are imposed for the entirety of the interim step either alone or in combination.

(2) For the final period, affected EGUs must have emission standards that have compliance periods that are no longer than each final reporting period and are imposed for the entirety of the final reporting period either alone or in combination.

(3) Compliance periods for each interim step and each final reporting period may take forms shorter than specified in this regulation, provided the schedules of compliance collectively end on the same schedule as each interim step and final reporting period.

(d) If your plan relies upon State measures in lieu of or in addition to emission standards for affected EGUs regulated under the plan, then the performance periods must be identical to the compliance periods for affected EGUs listed in paragraphs (c)(1) through (3) of this section.

§ 60.5775 What emission standards must I include in my plan?

(a) Emission standard(s) for affected EGUs included under your plan must be demonstrated to be quantifiable, verifiable, non-duplicative, permanent, and enforceable with respect to each affected EGU. The plan submittal must include the methods by which each emission standard meets each of the following requirements in paragraphs (b) through (f) of this section.

(b) An affected EGU's emission standard is quantifiable if it can be reliably measured in a manner that can be replicated.

(c) An affected EGU's emission standard is verifiable if adequate monitoring, recordkeeping and reporting requirements are in place to enable the State and the Administrator to independently evaluate, measure, and verify compliance with the emission standard.

(d) An affected EGU's emission standard is non-duplicative with respect to a State plan if it is not already incorporated as an emission standard in another State plan unless incorporated in multi-State plan.

(e) An affected EGU's emission standard is permanent if the emission standard must be met for each compliance period, unless it is replaced by another emission standard in an approved plan revision, or the State demonstrates in an approvable plan revision that the emission reductions from the emission standard are no longer necessary for the State to meet its State level of performance.

(f) An affected EGU's emission standard is enforceable if:

(1) A technically accurate limitation or requirement and the time period for the limitation or requirement are specified;

(2) Compliance requirements are clearly defined;

(3) The affected EGUs responsible for compliance and liable for violations can be identified;

(4) Each compliance activity or measure is enforceable as a practical matter; and

(5) The Administrator, the State, and third parties maintain the ability to enforce against violations (including if an affected EGU does not meet its emission standard based on its

emissions, its allowances if it is subject to a mass-based emission standard, or its ERCs if it is subject to a rate-based emission standard) and secure appropriate corrective actions, in the case of the Administrator pursuant to CAA sections 113(a)–(h), in the case of a State, pursuant to its plan, State law or CAA section 304, as applicable, and in the case of third parties, pursuant to CAA section 304.

§ 60.5780 What State measures may I rely upon in support of my plan?

You may rely upon State measures in support of your plan that are not emission standard(s) on affected EGUs, provided those State measures meet the requirements in paragraph (a) of this section.

(a) Each State measure is quantifiable, verifiable, non-duplicative, permanent, and enforceable with respect to each affected entity (*e.g.,* entities other than affected EGUs with no federally enforceable obligations under a State plan), and your plan supporting materials include the methods by which each State measure meets each of the following requirements in paragraphs (a)(1) through (5) of this section.

(1) A State measure is quantifiable with respect to an affected entity if it can be reliably measured in a manner that can be replicated.

(2) A State measure is verifiable with respect to an affected entity if adequate monitoring, recordkeeping and reporting requirements are in place to enable the State to independently evaluate, measure, and verify compliance with the State measure.

(3) A State measure is non-duplicative with respect to an affected entity if it is not already incorporated as a State measure or an emission standard in another State plan or State plan supporting material unless incorporated in a multi-State plan.

(4) A State measure is permanent with respect to an affected entity if the State measure must be met for at least each compliance period, or unless either it is replaced by another State measure in an approved plan revision, or the State demonstrates in an approved plan revision that the emission reductions from the State measure are no longer necessary for the State's affected EGUs to meet their mass-based CO_2 emission goal.

(5) A State measure is enforceable against an affected entity if:

(i) A technically accurate limitation or requirement and the time period for the limitation or requirement are specified;

(ii) Compliance requirements are clearly defined;

(iii) The affected entities responsible for compliance and liable for violations can be identified;

(iv) Each compliance activity or measure is enforceable as a practical matter; and

(v) The State maintains the ability to enforce violations and secure appropriate corrective actions.

(b) [Reserved]

§ 60.5785 What is the procedure for revising my plan?

(a) EPA-approved plans can be revised only with approval by the Administrator. The Administrator will approve a plan revision if it is satisfactory with respect to the applicable requirements of this subpart and any applicable requirements of subpart B of this part, including the requirement in § 60.5745(a)(3) to demonstrate achievement of the CO_2 emission performance rates or CO_2 emission goals in § 60.5855. If one (or more) of the elements of the plan set in § 60.5740 require revision with respect to achieving the CO_2 emission performance rates or CO_2 emission goals in § 60.5855, a request must be submitted to the Administrator indicating the proposed revisions to the plan to ensure the CO_2 emission performance rates or CO_2 emission goals are met. In addition, the following provisions in paragraphs (b) through (d) of this section may apply.

(b) You may submit revisions to a plan to adjust CO_2 emission goals according to § 60.5855(d).

(c) If your State is required to submit a notification according to § 60.5870(d) indicating a triggering of corrective measures as described in § 60.5740(a)(2)(i) and your plan does not already include corrective measures to be implemented if triggered, you must revise your State plan to include corrective measures to be implemented. The corrective measures must ensure achievement of the CO_2 emission performance rates or State CO_2 emission goal. Additionally, the corrective measures must achieve additional CO_2 emission reductions to offset any CO_2 emission performance shortfall relative to the overall interim period or final period CO_2 emission performance rate or State CO_2 emission goal. The State plan revision submission must explain how the corrective measures both make up for the shortfall and address the State plan deficiency that caused the shortfall. The State must submit the revised plan and explanation to the EPA within 24 months after submitting the State report required in § 60.5870(a) indicating the CO_2 emission performance deficiency in lieu of the requirements of § 60.28(a). The State must implement corrective measures within 6 months of the EPA's approval of a plan revision adding them. The shortfall must be made up as expeditiously as practicable.

(d) If your plan relies upon State measures, your backstop is triggered under § 60.5740(a)(3)(i), and your State measures plan backstop does not include a mechanism to make up the shortfall, you must revise your backstop emission standards to make up the shortfall. The shortfall must be made up as expeditiously as practicable.

(e) Reliability Safety Valve:

(1) In order to trigger a reliability safety valve, you must notify the EPA within 48 hours of an unforeseen, emergency situation that threatens reliability, such that your State will need a short-term modification of emission standards under a State plan for a specified affected EGU or EGUs. The EPA will consider the notification in § 60.5870(g)(1) to be an approved short-term modification to the State plan without needing to go through the full State plan revision process if the State provides a second notification to the EPA within seven days of the first notification. The short-term modification under a reliability safety valve allows modification to emission standards under the State plan for an affected EGU or EGUs for an initial period of up to 90 days. During that period of time, the affected EGU or EGUs will need to comply with the modified emission standards identified in the initial notification required under § 60.5870(g)(1) or amended in the second notification required under § 60.5870(g)(2). For the duration of the up to 90-day short-term modification, the CO_2 emissions of the affected EGU or EGUs that exceed their obligations under the originally approved State plan will not be counted against the State's CO_2 emission performance rate or CO_2 emission goal. The EPA reserves the right to review any such notification required under § 60.5870(g), and, in the event that the EPA finds such notification is improper, the EPA may disallow the short-term modification and affected EGUs must continue to operate under the approved State plan emission standards. As described more fully in § 60.5870(g)(3), at least seven days before the end of the initial 90-day reliability safety valve period, the State must notify the appropriate EPA regional office whether the reliability concern has been addressed and the affected EGU or EGUs can resume meeting the original emission standards established in the State plan prior to the short-term modification or whether a

serious, ongoing reliability issue necessitates the affected EGU or EGUs emitting beyond the amount allowed under the State plan.

(2) Plan revisions submitted pursuant to § 60.5870(g)(3) must meet the requirements for State plan revisions under § 60.5785(a).

§ 60.5790 What must I do to meet my plan obligations?

(a) To meet your plan obligations, you must demonstrate that your affected EGUs are complying with their emission standards as specified in § 60.5740, and you must demonstrate that the emission standards on affected EGUs, alone or in conjunction with any State measures, are resulting in achievement of the CO_2 emission performance rates or statewide CO_2 emission goals by affected EGUs using the procedures in paragraphs (b) through (d) of this section. If your plan requires the use of allowances for your affected EGUs to comply with their mass-based emission standards, you must follow the requirements under paragraph (b) of this section and § 60.5830. If your plan requires the use of ERCs for your affected EGUs to comply with their rate-based emission standards, you must follow the requirements under paragraphs (c) and (d) of this section and §§ 60.5795 through 60.5805.

(b) If you submit a plan that sets a mass-based emission trading program for your affected EGUs, the State plan must include emission standards and requirements that specify the allowance system, related compliance requirements and mechanisms, and the emission budget as appropriate. These requirements must include those listed in paragraphs (b)(1) through (5) of this section.

(1) CO_2 emission monitoring, reporting, and recordkeeping requirements for affected EGUs.

(2) Requirements for State allocation of allowances consistent with § 60.5815.

(3) Requirements for tracking of allowances, from issuance through submission for compliance, consistent with § 60.5820.

(4) The process for affected EGUs to demonstrate compliance (allowance ''true-up'' with reported CO_2 emissions) consistent with § 60.5825.

(5) Requirements that address potential increased CO_2 emissions from new sources, beyond the emissions expected from new sources if affected EGUs were given emission standards in the form of the subcategory-specific CO_2 emission performance rates. You may meet this requirement by requiring one of the options under paragraphs (b)(5)(i) through (iii) of this section.

(i) You may include, as part of your plan's supporting documentation, requirements enforceable as a matter of State law regulating CO_2 emissions from EGUs covered by subpart TTTT of this part under the mass-based CO_2 goal plus new source CO_2 emission complement applicable to your State in Table 4 of this subpart. If you choose this option, the term ''mass-based CO_2 goal plus new source CO_2 emission complement'' shall apply rather than ''CO_2 mass-based goal'' and the term ''CO_2 emission goal'' shall include ''mass-based CO_2 goal plus new source CO_2 emission complement'' in these emission guidelines.

(ii) You may include requirements in your State plan for emission budget allowance allocation methods that align incentives to generate to affected EGUs or EGUs covered by subpart TTTT of this part that result in the affected EGUs meeting the mass-based CO_2 emission goal;

(iii) You may submit for the EPA's approval, an equivalent method which requires affected EGUs to meet the mass-based CO_2 emission goal. The EPA will evaluate the approvability of such an alternative method on a case by case basis.

(c) If you submit a plan that sets rate-based emission standards on your affected EGUs, to meet the requirements of § 60.5775, you must follow the requirements in paragraphs (c)(1) through (4) of this section.

(1) You must require the owner or operator of each affected EGU covered by your plan to calculate an adjusted CO_2 emission rate to demonstrate compliance with its emission standard by factoring stack emissions and any ERCs into the following equation:

$$CO_2 emission\ rate = \frac{\sum M_{CO2}}{\sum MWh_{op} + \sum MWh_{ERC}}$$

Where:

CO_2 emission rate = An affected EGU's adjusted CO_2 emission rate that will be used to determine compliance with the applicable CO_2 emission standard.

M_{CO2} = Measured CO_2 mass in units of pounds (lbs) summed over the compliance period for an affected EGU.

MWh_{op} = Total net energy output over the compliance period for an affected EGU in units of MWh.

MWh_{ERC} = ERC replacement generation for an affected EGU in units of MWh (ERCs are denominated in whole integers as specified in paragraph (d) of this section).

(2) Your plan must specify that an ERC qualifies for the compliance demonstration specified in paragraph (c)(1) of this section if the ERC meets the requirements of paragraphs (c)(2)(i) through (iv) of this section.

(i) An ERC must have a unique serial number.

(ii) An ERC must represent one MWh of actual energy generated or saved with zero associated CO_2 emissions.

(iii) An ERC must only be issued to an eligible resource that meets the requirements of § 60.5800 or to an affected EGU that meets the requirements of § 60.5795 and must only be issued by a State or its State agent through an EPA-approved ERC tracking system that meets the requirements of § 60.5810, or by the EPA through an EPA-administered tracking system.

(iv) An ERC must be surrendered and retired only once for purpose of compliance with this regulation through an EPA-approved ERC tracking system that meets the requirements of § 60.5810, or by the EPA through an EPA-administered tracking system.

(3) Your plan must specify that an ERC does not qualify for the compliance demonstration specified in paragraph (c)(1) of this section if it does not meet the requirements of paragraph (c)(2) of this section or if any State has used that same ERC for purposes of demonstrating achievement of a CO_2 emission performance rate or CO_2 emission goal. The plan must additionally include provisions that address requirements for revocation or adjustment that apply if an ERC issued by the State is subsequently found to have been improperly issued.

(4) Your plan must include provisions either allowing for or restricting banking of ERCs between compliance periods for affected EGUs, and provisions not allowing any borrowing of any ERCs from future compliance periods by affected EGUs or eligible resources.

Emission Rate Credit Requirements

§ 60.5795 What affected EGUs qualify for generation of ERCs?

(a) For issuance of ERCs to the affected EGUs that generate them, the plan must specify the accounting method and process for ERC issuance. For plans that require that affected EGUs meet a rate-based CO_2 emission goal, where all affected EGUs have identical emission standards, you must specify the accounting method listed in paragraph (a)(1) of this section for generating ERCs. For plans that require affected EGUs to meet the CO_2 emission performance rates or CO_2 emission goals where affected EGUs have emission standards that are not equal for all affected EGUs, you must specify the accounting methods listed in paragraphs (a)(1) and (2) of this section for generating ERCs.

(1) You must include the calculation method for determining the number of ERCs, denominated in MWh, that may be generated by and issued to an affected EGU that is in compliance with its emission standard, based on the difference between its emission standard and its reported CO_2 emission rate for the compliance period; and

(2) You must include the calculation method for determining the number of ERCs, denominated in MWh, that may be issued to affected EGUs that meet the definition of a stationary combustion turbine based on the displaced emissions from affected EGUs not meeting the definition of a stationary combustion turbine, resulting from the difference between its annualized net energy output in MWh for the calendar year(s) in the compliance period and its net energy output in MWh for the 2012 calendar year (January 1, 2012, through December 31, 2012).

(b) Any ERCs generated through the method described as required by paragraph (a)(2) of this section must not be used by any affected EGUs other than steam generating units or IGCCs to demonstrate compliance as prescribed under § 60.5790(c)(1).

(c) Any states in a multi-State plan that requires the use of ERCs for affected EGUs to comply with their emission standards must have functionally equivalent requirements pursuant to paragraphs (a)(1) and (2) of this section for generating ERCs.

§ 60.5800 What other resources qualify for issuance of ERCs?

(a) ERCs may only be issued for generation or savings produced on or after January 1, 2022, to a resource that qualifies as an eligible resource because it meets each of the requirements in paragraphs (a)(1) through (4) of this section.

(1) Resources qualifying for eligibility only include resources that increased installed electrical generation nameplate capacity, or implemented new electrical savings measures, on or after January 1, 2013. If a resource had a nameplate capacity uprate, ERCs may be issued only for the difference in generation between its uprated nameplate capacity and its nameplate capacity prior to the uprate. ERCs must not be issued for generation for an uprate that followed a derate that occurred on or after January 1, 2013. A resource that is relicensed or receives a license extension is considered existing capacity and is not an eligible resource, unless it receives a capacity uprate as a result of the relicensing process that is reflected in its relicensed permit. In such a case, only the difference in nameplate capacity between its relicensed permit and its prior permit is eligible to be issued ERCs.

(2) The resource must be connected to, and deliver energy to or save electricity on, the electric grid in the contiguous United States.

(3) The resource must be located in either:

(i) A State whose affected EGUs are subject to rate-based emission standards pursuant to this regulation; or

(ii) A State with a mass-based CO_2 emission goal, and the resource can demonstrate (*e.g.,* through a power purchase agreement or contract for delivery) that the electricity generated is delivered with the intention to meet load in a State with affected EGUs which are subject to rate-based emission standards pursuant to this regulation, and was treated as a generation resource used to serve regional load that included the State whose affected EGUs are subject to rate-based emission standards. Notwithstanding any other provision of paragraph (a)(4) of this section, the only type of eligible resource in the State with mass-based emission standards is renewable generating technologies listed in (a)(4)(i) of this section.

(4) The resource falls into one of the following categories of resources:

(i) Renewable electric generating technologies using one of the following renewable energy resources: Wind, solar, geothermal, hydro, wave, tidal;

(ii) Qualified biomass;

(iii) Waste-to-energy (biogenic portion only);

(iv) Nuclear power;

(v) A non-affected combined heat and power (CHP) unit, including waste heat power;

(vi) A demand-side EE or demand-side management measure that saves electricity and is calculated on the basis of quantified ex post savings, not ''projected'' or ''claimed'' savings; or

(vii) A category identified in a State plan and approved by the EPA to generate ERCs.

(b) Any resource that does not meet the requirements of this subpart or an approved State plan cannot be issued ERCs for use by an affected EGU with its compliance demonstration required under § 60.5790(c).

(c) ERCs may not be issued to or for any of the following:

(1) New, modified, or reconstructed EGUs that are subject to subpart TTTT of this part, except CHP units that meet the requirements of a CHP unit under paragraph (a);

(2) EGUs that do not meet the applicability requirements of §§ 60.5845 and 60.5850, except CHP units that meet the requirements of a CHP unit under paragraph (a);

(3) Measures that reduce CO_2 emissions outside the electric power sector, including, for example, GHG offset projects representing emission reductions that occur in the forestry and agriculture sectors, direct air capture, and crediting of CO_2 emission reductions that occur in the transportation sector as a result of vehicle electrification; and

(4) Any measure not approved by the EPA for issuance of ERCs in connection with a specific State plan.

(d) You must include the appropriate requirements in paragraphs (d)(1) through (3) of this section for an applicable eligible resource in your plan.

(1) If qualified biomass is an eligible resource, the plan must include a description of why the proposed feedstocks or feedstock categories should qualify as an approach for controlling increases of CO_2 levels in the atmosphere as well as the proposed valuation of biogenic CO_2 emissions. In addition, for sustainably-derived agricultural and forest biomass feedstocks, the state plan must adequately demonstrate that such feedstocks appropriately control increases of CO_2 levels in the atmosphere and methods for adequately monitoring and verifying these feedstock sources and related sustainability practices. For all qualified biomass feedstocks, plans must specify how biogenic CO_2 emissions will be monitored and reported, and identify specific EM&V, tracking and auditing approaches.

(2) If waste-to-energy is an eligible resource, the plan must assess both the

capacity to strengthen existing or implement new waste reduction, reuse, recycling and composting programs, and measures to minimize any potential negative impacts of waste-to-energy operations on such programs. Additionally the plan must include a method for determining the proportion of total MWh generation from a waste-to-energy facility that is eligible for use in adjusting a CO_2 emission rate (*i.e.,* that which is generated from biogenic materials).

(3) If carbon capture and utilization (CCU) is an eligible resource in a plan, the plan must include analysis supporting how the proposed qualifying CCU technology results in CO_2 emission mitigation from affected EGUs and provide monitoring, reporting, and verification requirements to demonstrate the reductions.

(e) States and areas of Indian country that do not have any affected EGUs, and other countries, may provide ERCs to adjust CO_2 emissions provided they are connected to the contiguous U.S. grid and meet the other requirements for eligibility and eligible resources and the issuance of ERCs included in these emission guidelines, except that such States and other countries may not provide ERCs from resources described in § 60.5800(a)(4)(vi).

§ 60.5805 What is the process for the issuance of ERCs?

If your plan uses ERCs your plan must include the process and requirements for issuance of ERCs to affected EGUs and eligible resources set forth in paragraphs (a) through (f) of this section.

(a) *Eligibility application.* Your plan must require that, to receive ERCs, the owner or operator must submit an eligibility application to you that demonstrates that the requirements of your State plan as approved by the EPA as meeting § 60.5795 (for an affected EGU) or § 60.5800 (for an eligible resource) are met, and, in the case of an eligible resource, includes at a minimum:

(1) Documentation that the eligibility application has only been submitted to you, or pursuant to an EPA-approved multi-State collaborative approach;

(2) An EM&V plan that meets the requirements of the State plan as approved by the EPA as meeting § 60.5830; and

(3) A verification report from an independent verifier that verifies the eligibility of the eligible resource to be issued an ERC and that the EM&V plan meets the requirements of the State plan as approved by the EPA of meeting § 60.5805.

(b) *Registration.* Your plan must require that any affected EGU or eligible resource register with an ERC tracking system that meets the requirements of § 60.5810 prior to the issuance of ERCs, and your plan must specify that you will only register an affected EGU or eligible resource after you approve its eligibility application and determine that the requirements of paragraph (a) of this section are met.

(c) *M&V reports.* For an eligible resource registered pursuant to paragraph (b) of this section, your plan must require that, prior to issuance of ERCs by you, the owner or operator must submit the following:

(1) An M&V report that meets the requirements of your State plan as approved by the EPA as meeting § 60.5835; and

(2) A verification report from an independent verifier that verifies that the requirements for the M&V report are met.

(e) *Issuance of ERCs.* Your plan must specify your procedure for issuance of ERCs based on your review of an M&V report and verification report, and must require that ERCs be issued only on the basis of energy actually generated or saved, and that only one ERC is issued for each verified MWh.

(f) *Tracking system.* Your plan must require that ERCs may only be issued through an ERC tracking system approved as part of the State plan.

(g) *Error adjustment.* Your plan must include a mechanism to adjust the number of ERCs issued if any are issued based on error (clerical, formula input error, etc.).

(h) *Qualification status of an eligible resource.* Your plan must include a mechanism to temporarily or permanently revoke the qualification status of an eligible resource, such that it can no longer be issued ERCs for at least the duration that it does not meet the requirements for being issued ERCs in your State plan.

(i) *Qualification status of an independent verifier*—(1) *Eligibility.* To be an independent verifier, a person must be approved by the State as:

(A) An independent verifier, as defined by this regulation; and

(B) Eligible to verify eligibility applications, EM&V plans, and/or M&V reports per the requirements of the approved State plan as meeting §§ 60.5830 and 60.5835 respectively.

(2) *Revocation of qualification.* Your plan must include a mechanism to temporarily or permanently revoke the qualification status of an independent verifier, such that it can no longer verify eligibility applications, EM&V plans or M&V reports for at least the duration of the period it does not meet the requirements of your State plan.

§ 60.5810 What applicable requirements are there for an ERC tracking system?

(a) Your plan must include provisions for an ERC tracking system, if applicable, that meets the following requirements:

(1) It electronically records the issuance of ERCs, transfers of ERCs among accounts, surrender of ERCs by affected EGUs as part of a compliance demonstration, and retirement or cancellation of ERCs; and

(2) It documents and provides electronic, internet-based public access to all information that supports the eligibility of eligible resources and issuance of ERCs and functionality to generate reports based on such information, which must include, for each ERC, an eligibility application, EM&V plan, M&V reports, and independent verifier verification reports.

(b) If approved in a State plan, an ERC tracking system may provide for transfers of ERCs to or from another ERC tracking system approved in a State plan, or provide for transfers of ERCs to or from an EPA-administered ERC tracking system used to administer a Federal plan.

Mass Allocation Requirements

§ 60.5815 What are the requirements for State allocation of allowances in a mass-based program?

(a) For a mass-based trading program, a State plan must include requirements for CO_2 allowance allocations according to paragraphs (b) through (f) of this section.

(b) Provisions for allocation of allowances for each compliance period prior to the beginning of the compliance period.

(c) Provisions for allocation of set-aside allowance, if applicable, must be established to ensure that the eligible resources must meet the same requirements for the ERC eligible resource requirements of § 60.5800, and the State must include eligibility application and verification provisions equivalent to those for ERCs in § 60.5805 and EM&V plan and M&V report provisions that meet the requirements of § 60.5830 and § 60.5835.

(d) Provisions for adjusting allocations if the affected EGUs or eligible resources are incorrectly allocated CO_2 allowances.

(e) Provisions allowing for or restricting banking of allowances between compliance periods for affected EGUs.

(f) Provisions not allowing any borrowing of allowances from future compliance periods by affected EGUs.

§ 60.5820 What are my allowance tracking requirements?

(a) Your plan must include provisions for an allowance tracking system, if applicable, that meets the following requirements:

(1) It electronically records the issuance of allowances, transfers of allowances among accounts, surrender of allowances by affected EGUs as part of a compliance demonstration, and retirement of allowances; and

(2) It documents and provides electronic, internet-based public access to all information that supports the eligibility of eligible resources and issuance of set aside allowances, if applicable, and functionality to generate reports based on such information, which must include, for each set aside allowance, an eligibility application, EM&V plan, M&V reports, and independent verifier verification reports.

(b) If approved in a State plan, an allowance tracking system may provide for transfers of allowances to or from another allowance tracking system approved in a State plan, or provide for transfers of allowances to or from an EPA-administered allowance tracking system used to administer a Federal plan.

§ 60.5825 What is the process for affected EGUs to demonstrate compliance in a mass-based program?

(a) A plan must require an affected EGU's owners or operators to demonstrate compliance with emission standards in a mass based program by holding an amount of allowances not less than the tons of total CO_2 emissions for such compliance period from the affected EGUs in the account for the affected EGU's emissions in the allowance tracking system required under § 60.5820 during the applicable compliance period.

(b) In a mass-based trading program a plan may allow multiple affected EGUs co-located at the same facility to demonstrate that they are meeting the applicable emission standards on a facility-wide basis by the owner or operator holding enough allowances to cover the CO_2 emissions of all the affected EGUs at the facility.

(1) If there are not enough allowances to cover the facility's affected EGUs' CO_2 emissions then there must be provisions for determining the compliance status of each affected EGU located at that facility.

(2) [Reserved]

Evaluation Measurement and Verification Plans and Monitoring and Verification Reports

§ 60.5830 What are the requirements for EM&V plans for eligible resources?

(a) If your plan requires your affected EGUs to meet their emission standards in accordance with § 60.5790, your plan must include requirements that any EM&V plan that is submitted in accordance with the requirements of § 60.5805, in support of the issuance of an ERC or set-aside allowance that can be used in accordance with § 60.5790, must meet the EM&V criteria approved as part of your State plan.

(b) Your plan must require each EM&V plan to include identification of the eligible resource.

(c) Your plan must require that an EM&V plan must contain specific criteria, as applicable to the specific eligible resource.

(1) For RE resources, your plan must include requirements discussing how the generation data will be physically measured on a continuous basis using, for example, a revenue-quality meter.

(2) For demand-side EE, your plan must require that each EM&V plan quantify and verify electricity savings on a retrospective (ex-post) basis using industry best-practice EM&V protocols and methods that yield accurate and reliable measurements of electricity savings. Your plan must also require each EM&V plan to include an assessment of the independent factors that influence the electricity savings, the expected life of the savings (in years), and a baseline that represents what would have happened in the absence of the demand-side EE activity. Additionally, your plan must require that each EM&V plan include a demonstration of how the industry best-practices protocol and methods were applied to the specific activity, project, measure, or program covered in the EM&V plan, and include an explanation of why these protocols or methods were selected. EM&V plans must require eligible resources to demonstrate how all such best-practice approaches will be applied for the purposes of quantifying and verifying MWh results. Subsequent reporting of demand-side EE savings values must demonstrate and explain how the EM&V plan was followed.

§ 60.5835 What are the requirements for M&V reports for eligible resources?

(a) If your plan requires your affected EGUs to meet their emission standards in accordance with § 60.5790, your plan must include requirements that any M&V report that is submitted in accordance with the requirements of § 60.5805, in support of the issuance of an ERC or set-aside allocation that can be used in accordance with § 60.5790, must meet the requirements of this section.

(b) Your plan must require that each M&V report include the following:

(1) For the first M&V report submitted, documentation that the energy-generating resources, energy-saving measures, or practices were installed or implemented consistent with the description in the approved eligibility application required in § 60.5805(a).

(2) Each M&V report submitted must include the following:

(i) Identification of the time period covered by the M&V report;

(ii) A description of how relevant quantification methods, protocols, guidelines, and guidance specified in the EM&V plan were applied during the reporting period to generate the quantified MWh of generation or MWh of energy savings;

(iii) Documentation (including data) of the energy generation and/or energy savings from any activity, project, measure, resource, or program addressed in the EM&V plan, quantified and verified in MWh for the period covered by the M&V report, in accordance with its EM&V plan, and based on ex-post energy generation or savings; and

(iv) Documentation of any change in the energy generation or savings capability of the eligible resource from the description of the resource in the approved eligibility application during the period covered by the M&V report and the date on which the change occurred, and/or demonstration that the eligible resource continued to meet the requirements of § 60.5800.

Applicability of Plans to Affected EGUs

§ 60.5840 Does this subpart directly affect EGU owners or operators in my State?

(a) This subpart does not directly affect EGU owners or operators in your State. However, affected EGU owners or operators must comply with the plan that a State or States develop to implement the emission guidelines contained in this subpart.

(b) If a State does not submit a final plan to implement and enforce the emission guidelines contained in this subpart, or an initial submittal for which an extension to submit a final plan can be granted, by September 6, 2016, or the EPA disapproves a final plan, the EPA will implement and enforce a Federal plan, as provided in § 60.5720, applicable to each affected EGU within the State that commenced construction on or before January 8, 2014.

§ 60.5845 What affected EGUs must I address in my State plan?

(a) The EGUs that must be addressed by your plan are any affected steam generating unit, IGCC, or stationary combustion turbine that commenced construction on or before January 8, 2014.

(b) An affected EGU is a steam generating unit, IGCC, or stationary combustion turbine that meets the relevant applicability conditions specified in paragraph (b)(1) through (3) of this section, as applicable, except as provided in § 60.5850.

(1) Serves a generator or generators connected to a utility power distribution system with a nameplate capacity greater than 25 MW-net (*i.e.,* capable of selling greater than 25 MW of electricity);

(2) Has a base load rating (*i.e.,* design heat input capacity) greater than 260 GJ/hr (250 MMBtu/hr) heat input of fossil fuel (either alone or in combination with any other fuel); and

(3) Stationary combustion turbines that meet the definition of either a combined cycle or combined heat and power combustion turbine.

§ 60.5850 What EGUs are excluded from being affected EGUs?

EGUs that are excluded from being affected EGUs are:

(a) EGUs that are subject to subpart TTTT of this part as a result of commencing construction after the subpart TTTT applicability date;

(b) Steam generating units and IGCCs that are, and always have been, subject to a federally enforceable permit limiting annual net-electric sales to one-third or less of its potential electric output, or 219,000 MWh or less;

(c) Non-fossil units (*i.e.,* units that are capable of combusting 50 percent or more non-fossil fuel) that have always historically limited the use of fossil fuels to 10 percent or less of the annual capacity factor or are subject to a federally enforceable permit limiting fossil fuel use to 10 percent or less of the annual capacity factor;

(d) Stationary combustion turbines not capable of combusting natural gas (*e.g.,* not connected to a natural gas pipeline);

(e) EGUs that are combined heat and power units that have always historically limited, or are subject to a federally enforceable permit limiting, annual net-electric sales to a utility distribution system to no more than the greater of either 219,000 MWh or the product of the design efficiency and the potential electric output;

(f) EGUs that serve a generator along with other steam generating unit(s), IGCC(s), or stationary combustion turbine(s) where the effective generation capacity (determined based on a prorated output of the base load rating of each steam generating unit, IGCC, or stationary combustion turbine) is 25 MW or less;

(g) EGUs that are a municipal waste combustor unit that is subject to subpart Eb of this part; and

(h) EGUs that are a commercial or industrial solid waste incineration unit that is subject to subpart CCCC of this part.

§ 60.5855 What are the CO_2 emission performance rates for affected EGUs?

(a) You must require, in your plan, emission standards on affected EGUs to meet the CO_2 emission performance rates listed in Table 1 of this subpart except as provided in paragraph (b) of this section. In addition, you must set CO_2 emission performance rates for the interim steps, according to paragraph (a)(1) of this section, except as provided in paragraph (b) of this section.

(1) You must set CO_2 emission performance rates for your affected EGUs to meet during the interim step periods on average and as applicable for the two subcategories of affected EGUs.

(2) [Reserved]

(b) You may elect to require your affected EGUs to meet emission standards that differ from the CO_2 emission performance rates listed in Table 1 of this subpart, provided that you demonstrate that the affected EGUs in your State will collectively meet their CO_2 emission performance rate by achieving statewide emission goals that are equivalent and no less stringent than the CO_2 emission performance rates listed in Table 1, and provided that your equivalent statewide CO_2 emission goals take one of the following forms:

(1) Average statewide rate-based CO_2 emission goals listed in Table 2 of this subpart, except as provided in paragraphs (c) and (d); or

(2) Cumulative statewide mass-based CO_2 emission goals listed in Table 3 of this subpart, except as provided in paragraphs (c) and (d) of this section.

(c) If your plan meets CO_2 emission goals listed in paragraphs (b)(1) or (2) of this section you must develop your own interim step goals and final reporting period goal for your affected EGUs to meet either on average (in the case of rate-based goals) or cumulatively (in the case of mass-based goals). Additionally the following applies if you develop your own goals:

(1) The interim period and interim steps CO_2 emission goals must be in the same form, either both rate (in units of pounds per net MWh) or both mass (in tons); and

(2) You must set interim step goals that will either on average or cumulatively meet the State's interim period goal, as applicable to a rate-based or mass-based CO_2 emission goal.

(d) Your plan's interim period and final period CO_2 emission goals required to be met pursuant to paragraph (b)(1) or (2) of this section, may be changed in the plan only according to situations listed in paragraphs (d)(1) through (3) of this section. If a situation requires a plan revision, you must follow the procedures in § 60.5785 to submit a plan revision.

(1) If your plan implements CO_2 emission goals, you may submit a plan or plan revision, allowed in § 60.5785, to make corrections to them, subject to EPA's approval, as a result of changes in the inventory of affected EGUs; and

(2) If you elect to require your affected EGUs to meet emission standards to meet mass-based CO_2 emission goals in your plan, you may elect to incorporate, as a matter of state law, the mass emissions from EGUs that are subject to subpart TTTT of this part that are considered new affected EGUs under subpart TTTT of this part.

(e) If your plan relies upon State measures in addition to or in lieu of emission standards, you must only use the mass-based goals allowed for in paragraph (b)(2) of this section to demonstrate that your affected EGUs are meeting the required emissions performance.

(f) Nothing in this subpart precludes an affected EGU from complying with its emission standard or you from meeting your obligations under the State plan.

§ 60.5860 What applicable monitoring, recordkeeping, and reporting requirements do I need to include in my plan for affected EGUs?

(a) Your plan must include monitoring for affected EGUs that is no less stringent than what is described in (a)(1) through (8) of this section.

(1) The owner or operator of an affected EGU (or group of affected EGUs that share a monitored common stack) that is required to meet rate-based or mass-based emission standards must prepare a monitoring plan in accordance with the applicable provisions in § 75.53(g) and (h) of this chapter, unless such a plan is already in place under another program that requires CO_2 mass emissions to be monitored and reported according to part 75 of this chapter.

(2) For rate-based emission standards, each compliance period shall include

only ''valid operating hours'' in the compliance period, *i.e.,* full or partial unit (or stack) operating hours for which:

(i) ''Valid data'' (as defined in § 60.5880) are obtained for all of the parameters used to determine the hourly CO_2 mass emissions (lbs). For the purposes of this subpart, substitute data recorded under part 75 of this chapter are not considered to be valid data; and

(ii) The corresponding hourly net energy output value is also valid data (**Note:** For operating hours with no useful output, zero is considered to be a valid value).

(3) For rate-based emission standards, the owner or operator of an affected EGU must measure and report the hourly CO_2 mass emissions (lbs) from each affected unit using the procedures in paragraphs (a)(3)(i) through (vi) of this section, except as otherwise provided in paragraph (a)(4) of this section.

(i) The owner or operator of an affected EGU must install, certify, operate, maintain, and calibrate a CO_2 continuous emissions monitoring system (CEMS) to directly measure and record CO_2 concentrations in the affected EGU exhaust gases emitted to the atmosphere and an exhaust gas flow rate monitoring system according to § 75.10(a)(3)(i) of this chapter. As an alternative to direct measurement of CO_2 concentration, provided that the affected EGU does not use carbon separation (*e.g.,* carbon capture and storage), the owner or operator of an affected EGU may use data from a certified oxygen (O_2) monitor to calculate hourly average CO_2 concentrations, in accordance with § 75.10(a)(3)(iii) of this chapter. However, when an O_2 monitor is used this way, it only quantifies the combustion CO_2; therefore, if the EGU is equipped with emission controls that produce non-combustion CO_2 (*e.g.,* from sorbent injection), this additional CO_2 must be accounted for, in accordance with section 3 of appendix G to part 75 of this chapter. If CO_2 concentration is measured on a dry basis, the owner or operator of the affected EGU must also install, certify, operate, maintain, and calibrate a continuous moisture monitoring system, according to § 75.11(b) of this chapter. Alternatively, the owner or operator of an affected EGU may either use an appropriate fuel-specific default moisture value from § 75.11(b) or submit a petition to the Administrator under § 75.66 of this chapter for a site-specific default moisture value.

(ii) For each ''valid operating hour'' (as defined in paragraph (a)(2) of this section), calculate the hourly CO_2 mass emission rate (tons/hr), either from Equation F–11 in Appendix F to part 75 of this chapter (if CO_2 concentration is measured on a wet basis), or by following the procedure in section 4.2 of Appendix F to part 75 of this chapter (if CO_2 concentration is measured on a dry basis).

(iii) Next, multiply each hourly CO_2 mass emission rate by the EGU or stack operating time in hours (as defined in § 72.2 of this chapter), to convert it to tons of CO_2. Multiply the result by 2,000 lbs/ton to convert it to lbs.

(iv) The hourly CO_2 tons/hr values and EGU (or stack) operating times used to calculate CO_2 mass emissions are required to be recorded under § 75.57(e) of this chapter and must be reported electronically under § 75.64(a)(6), if required by a plan. The owner or operator must use these data, or equivalent data, to calculate the hourly CO_2 mass emissions.

(v) Sum all of the hourly CO_2 mass emissions values from paragraph (a)(3)(ii) of this section over the entire compliance period.

(vi) For each continuous monitoring system used to determine the CO_2 mass emissions from an affected EGU, the monitoring system must meet the applicable certification and quality assurance procedures in § 75.20 of this chapter and Appendices A and B to part 75 of this chapter.

(4) The owner or operator of an affected EGU that exclusively combusts liquid fuel and/or gaseous fuel may, as an alternative to complying with paragraph (a)(3) of this section, determine the hourly CO_2 mass emissions according to paragraphs (a)(4)(i) through (a)(4)(vi) of this section.

(i) Implement the applicable procedures in appendix D to part 75 of this chapter to determine hourly EGU heat input rates (MMBtu/hr), based on hourly measurements of fuel flow rate and periodic determinations of the gross calorific value (GCV) of each fuel combusted. The fuel flow meter(s) used to measure the hourly fuel flow rates must meet the applicable certification and quality-assurance requirements in sections 2.1.5 and 2.1.6 of appendix D to part 75 (except for qualifying commercial billing meters). The fuel GCV must be determined in accordance with section 2.2 or 2.3 of appendix D, as applicable.

(ii) For each measured hourly heat input rate, use Equation G–4 in Appendix G to part 75 of this chapter to calculate the hourly CO_2 mass emission rate (tons/hr).

(iii) For each ''valid operating hour'' (as defined in paragraph (a)(2) of this section), multiply the hourly tons/hr CO_2 mass emission rate from paragraph (a)(4)(ii) of this section by the EGU or stack operating time in hours (as defined in § 72.2 of this chapter), to convert it to tons of CO_2. Then, multiply the result by 2,000 lbs/ton to convert it to lbs.

(iv) The hourly CO_2 tons/hr values and EGU (or stack) operating times used to calculate CO_2 mass emissions are required to be recorded under § 75.57(e) of this chapter and must be reported electronically under § 75.64(a)(6), if required by a plan. You must use these data, or equivalent data, to calculate the hourly CO_2 mass emissions.

(v) Sum all of the hourly CO_2 mass emissions values (lb) from paragraph (a)(4)(iii) of this section over the entire compliance period.

(vi) The owner or operator of an affected EGU may determine site-specific carbon-based F-factors (F_c) using Equation F–7b in section 3.3.6 of appendix F to part 75 of this chapter, and may use these F_c values in the emissions calculations instead of using the default F_c values in the Equation G–4 nomenclature.

(5) For both rate-based and mass-based standards, the owner or operator of an affected EGU (or group of affected units that share a monitored common stack) must install, calibrate, maintain, and operate a sufficient number of watt meters to continuously measure and record on an hourly basis net electric output. Measurements must be performed using 0.2 accuracy class electricity metering instrumentation and calibration procedures as specified under ANSI Standards No. C12.20. Further, the owner or operator of an affected EGU that is a combined heat and power facility must install, calibrate, maintain and operate equipment to continuously measure and record on an hourly basis useful thermal output and, if applicable, mechanical output, which are used with net electric output to determine net energy output. The owner or operator must use the following procedures to calculate net energy output, as appropriate for the type of affected EGU(s).

(i) Determine P_{net} the hourly net energy output in MWh. For rate-based standards, perform this calculation only for valid operating hours (as defined in paragraph (a)(2) of this section). For mass-based standards, perform this calculation for all unit (or stack) operating hours, *i.e.,* full or partial hours in which any fuel is combusted.

(ii) If there is no net electrical output, but there is mechanical or useful thermal output, either for a particular valid operating hour (for rate-based applications), or for a particular operating hour (for mass-based applications), the owner or operator of the affected EGU must still determine the net energy output for that hour.

(iii) For rate-based applications, if there is no (*i.e.,* zero) gross electrical, mechanical, or useful thermal output for a particular valid operating hour, that hour must be used in the compliance determination. For hours or partial hours where the gross electric output is equal to or less than the auxiliary loads, net electric output shall be counted as zero for this calculation.

(iv) Calculate P_{net} for your affected EGU (or group of affected EGUs that share a monitored common stack) using the following equation. All terms in the equation must be expressed in units of MWh. To convert each hourly net energy output value reported under part 75 of this chapter to MWh, multiply by the corresponding EGU or stack operating time.

$$P_{net} = \frac{(Pe)_{ST} + (Pe)_{CT} + (Pe)_{IE} - (Pe)_{A}}{\text{TDF}} + [\,(Pt)_{PS} + (Pt)_{HR} + (Pt)_{IE}\,]$$

Where:

P_{net} = Net energy output of your affected EGU for each valid operating hour (as defined in 60.5860(a)(2)) in MWh.

$(Pe)_{ST}$ = Electric energy output plus mechanical energy output (if any) of steam turbines in MWh.

$(Pe)_{CT}$ = Electric energy output plus mechanical energy output (if any) of stationary combustion turbine(s) in MWh.

$(Pe)_{IE}$ = Electric energy output plus mechanical energy output (if any) of your affected EGU's integrated equipment that provides electricity or mechanical energy to the affected EGU or auxiliary equipment in MWh.

$(Pe)_{A}$ = Electric energy used for any auxiliary loads in MWh.

$(Pt)_{PS}$ = Useful thermal output of steam (measured relative to SATP conditions, as applicable) that is used for applications that do not generate additional electricity, produce mechanical energy output, or enhance the performance of the affected EGU. This is calculated using the equation specified in paragraph (a)(5)(v) of this section in MWh.

$(Pt)_{HR}$ = Non-steam useful thermal output (measured relative to SATP conditions, as applicable) from heat recovery that is used for applications other than steam generation or performance enhancement of the affected EGU in MWh.

$(Pt)_{IE}$ = Useful thermal output (relative to SATP conditions, as applicable) from any integrated equipment is used for applications that do not generate additional steam, electricity, produce mechanical energy output, or enhance the performance of the affected EGU in MWh.

TDF = Electric Transmission and Distribution Factor of 0.95 for a combined heat and power affected EGU where at least on an annual basis 20.0 percent of the total gross or net energy output consists of electric or direct mechanical output and 20.0 percent of the total net energy output consist of useful thermal output on a 12-operating month rolling average basis, or 1.0 for all other affected EGUs.

(v) If applicable to your affected EGU (for example, for combined heat and power), you must calculate $(Pt)_{PS}$ using the following equation:

$$(Pt)_{PS} = \frac{Q_m \times H}{CF}$$

Where:

Q_m = Measured steam flow in kilograms (kg) (or pounds (lbs)) for the operating hour.

H = Enthalpy of the steam at measured temperature and pressure (relative to SATP conditions or the energy in the condensate return line, as applicable) in Joules per kilogram (J/kg) (or Btu/lb).

CF = Conversion factor of 3.6×10^9 J/MWh or 3.413×10^6 Btu/MWh.

(vi) For rate-based standards, sum all of the values of P_{net} for the valid operating hours (as defined in paragraph (a)(2) of this section), over the entire compliance period. Then, divide the total CO_2 mass emissions for the valid operating hours from paragraph (a)(3)(v) or (a)(4)(v) of this section, as applicable, by the sum of the P_{net} values for the valid operating hours plus any ERC replacement generation (as shown in § 60.5790(c)), to determine the CO_2 emissions rate (lb/net MWh) for the compliance period.

(vii) For mass-based standards, sum all of the values of P_{net} for all operating hours, over the entire compliance period.

(6) In accordance with § 60.13(g), if two or more affected EGUs implementing the continuous emissions monitoring provisions in paragraph (a)(2) of this section share a common exhaust gas stack and are subject to the same emissions standard, the owner or operator may monitor the hourly CO_2 mass emissions at the common stack in lieu of monitoring each EGU separately. If an owner or operator of an affected EGU chooses this option, the hourly net electric output for the common stack must be the sum of the hourly net electric output of the individual affected EGUs and the operating time must be expressed as ''stack operating hours'' (as defined in § 72.2 of this chapter).

(7) In accordance with § 60.13(g), if the exhaust gases from an affected EGU implementing the continuous emissions monitoring provisions in paragraph (a)(2) of this section are emitted to the atmosphere through multiple stacks (or if the exhaust gases are routed to a common stack through multiple ducts and you elect to monitor in the ducts), the hourly CO_2 mass emissions and the ''stack operating time'' (as defined in § 72.2 of this chapter) at each stack or duct must be monitored separately. In this case, the owner or operator of an affected EGU must determine compliance with an applicable emissions standard by summing the CO_2 mass emissions measured at the individual stacks or ducts and dividing by the net energy output for the affected EGU.

(8) Consistent with § 60.5775 or § 60.5780, if two or more affected EGUs serve a common electric generator, you must apportion the combined hourly net energy output to the individual affected EGUs according to the fraction of the total steam load contributed by each EGU. Alternatively, if the EGUs are identical, you may apportion the combined hourly net electrical load to the individual EGUs according to the fraction of the total heat input contributed by each EGU.

(b) For mass-based standards, the owner or operator of an affected EGU must determine the CO_2 mass emissions (tons) for the compliance period as follows:

(1) For each operating hour, calculate the hourly CO_2 mass (tons) according to paragraph (a)(3) or (4) of this section, except that a complete data record is required, *i.e.,* CO_2 mass emissions must be reported for each operating hour. Therefore, substitute data values recorded under part 75 of this chapter for CO_2 concentration, stack gas flow rate, stack gas moisture content, fuel flow rate and/or GCV shall be used in the calculations; and

(2) Sum all of the hourly CO_2 mass emissions values over the entire compliance period.

(3) The owner or operator of an affected EGU must install, calibrate, maintain, and operate a sufficient number of watt meters to continuously

measure and record on an hourly basis net electric output. Measurements must be performed using 0.2 accuracy class electricity metering instrumentation and calibration procedures as specified under ANSI Standards No. C12.20. Further, the owner or operator of an affected EGU that is a combined heat and power facility must install, calibrate, maintain and operate equipment to continuously measure and record on an hourly basis useful thermal output and, if applicable, mechanical output, which are used with net electric output to determine net energy output (P_{net}). The owner or operator must calculate net energy output according to paragraphs (a)(5)(i)(A) and (B) of this section.

(c) Your plan must require the owner or operator of each affected EGU covered by your plan to maintain the records, as described in paragraphs (b)(1) and (2) of this section, for at least 5 years following the date of each compliance period, occurrence, measurement, maintenance, corrective action, report, or record.

(1) The owner or operator of an affected EGU must maintain each record on site for at least 2 years after the date of each compliance period, occurrence, measurement, maintenance, corrective action, report, or record, whichever is latest, according to § 60.7. The owner or operator of an affected EGU may maintain the records off site and electronically for the remaining year(s).

(2) The owner or operator of an affected EGU must keep all of the following records, in a form suitable and readily available for expeditious review:

(i) All documents, data files, and calculations and methods used to demonstrate compliance with an affected EGU's emission standard under § 60.5775.

(ii) Copies of all reports submitted to the State under paragraph (c) of this section.

(iii) Data that are required to be recorded by 40 CFR part 75 subpart F.

(iv) Data with respect to any ERCs generated by the affected EGU or used by the affected EGU in its compliance demonstration including the information in paragraphs (c)(2)(iv)(A) and (B) of this section.

(A) All documents related to any ERCs used in a compliance demonstration, including each eligibility application, EM&V plan, M&V report, and independent verifier verification report associated with the issuance of each specific ERC.

(B) All records and reports relating to the surrender and retirement of ERCs for compliance with this regulation, including the date each individual ERC with a unique serial identification number was surrendered and/or retired.

(d) Your plan must require the owner or operator of an affected EGU covered by your plan to include in a report submitted to you at the end of each compliance period the information in paragraphs (d)(1) through (5) of this section.

(1) Owners or operators of an affected EGU must include in the report all hourly CO_2 emissions, for each affected EGU (or group of affected EGUs that share a monitored common stack).

(2) For rate-based standards, each report must include:

(i) The hourly CO_2 mass emission rate values (tons/hr) and unit (or stack) operating times, (as monitored and reported according to part 75 of this chapter), for each valid operating hour in the compliance period;

(ii) The net electric output and the net energy output (P_{net}) values for each valid operating hour in the compliance period;

(iii) The calculated CO_2 mass emissions (lb) for each valid operating hour in the compliance period;

(iv) The sum of the hourly net energy output values and the sum of the hourly CO_2 mass emissions values, for all of the valid operating hours in the compliance period;

(v) ERC replacement generation (if any), properly justified (see paragraph (c)(5) of this section); and

(vi) The calculated CO_2 mass emission rate for the compliance period (lbs/net MWh).

(3) For mass-based standards, each report must include:

(i) The hourly CO_2 mass emission rate value (tons/hr) and unit (or stack) operating time, as monitored and reported according to part 75 of this chapter, for each unit or stack operating hour in the compliance period;

(ii) The calculated CO_2 mass emissions (tons) for each unit or stack operating hour in the compliance period;

(iii) The sum of the CO_2 mass emissions (tons) for all of the unit or stack operating hours in the compliance period;

(iv) The net electric output and the net energy output (P_{net}) values for each unit or stack operating hour in the compliance period; and

(v) The sum of the hourly net energy output values for all of the unit or stack operating hours in the compliance period.

(vi) Notwithstanding the requirements in paragraphs (c)(3)(i) through (c)(3)(iii) of this section, if the compliance period is a discrete number of calendar years (*e.g.,* one year, three years), in lieu of reporting the information specified in those paragraphs, the owner or operator may report:

(A) The cumulative annual CO_2 mass emissions (tons) for each year of the compliance period, derived from the electronic emissions report for the fourth calendar quarter of that year, submitted to EPA under § 75.64(a) of this chapter; and

(B) The sum of the cumulative annual CO_2 mass emissions values from paragraph (c)(3)(v)(A) of this section, if the compliance period includes multiple years.

(4) For each affected EGU's compliance period, the report must also include the applicable emission standard and demonstration that it met the emission standard. An owner or operator must also include in the report the affected EGU's calculated emission performance as a CO_2 emission rate or cumulative mass in units of the emission standard required in §§ 60.5790(b) through (c) and 60.5855, as applicable.

(5) If the owner or operator of an affected EGU is complying with an emission standard by using ERCs, they must include in the report a list of all unique ERC serial numbers that were retired in the compliance period, and, for each ERC, the date an ERC was surrendered and retired and eligible resource identification information sufficient to demonstrate that it meets the requirements of § 60.5800 and qualifies to be issued ERCs (including location, type of qualifying generation or savings, date commenced generating or saving, and date of generation or savings for which the ERC was issued).

(6) If the owner or operator of an affected EGU is complying with an emission standard by using allowances, they must include in the report a list of all unique allowance serial numbers that were retired in the compliance period, and, for each allowance, the date an allowance was surrendered and retired and if the allowance was a set-aside allowance the eligible resource identification information sufficient to demonstrate that it meets the requirements of § 60.5815(c) and qualifies to be issued set-aside allowances (including location, type of qualifying generation or savings, date commenced generating or saving, and date of generation or savings for which the allowance was issued).

(e) The owner or operator of an affected EGU must follow any additional requirements for monitoring, recordkeeping and reporting in a plan that are required under § 60.5745(a)(4), if applicable.

(f) If an affected EGU captures CO_2 to meet the applicable emission limit, the owner or operator must report in accordance with the requirements of 40 CFR part 98 subpart PP and either:

(1) Report in accordance with the requirements of 40 CFR part 98 subpart RR, if injection occurs on-site;

(2) Transfer the captured CO_2 to an EGU or facility that reports in accordance with the requirements of 40 CFR part 98 subpart RR, if injection occurs off-site; or

(3) Transfer the captured CO_2 to a facility that has received an innovative technology waiver from EPA pursuant to paragraph (g) of this section.

(g) Any person may request the Administrator to issue a waiver of the requirement that captured CO_2 from an affected EGU be transferred to a facility reporting under 40 CFR part 98 subpart RR. To receive a waiver, the applicant must demonstrate to the Administrator that its technology will store captured CO_2 as effectively as geologic sequestration, and that the proposed technology will not cause or contribute to an unreasonable risk to public health, welfare, or safety. In making this determination, the Administrator shall consider (among other factors) operating history of the technology, whether the technology will increase emissions or other releases of any pollutant other than CO_2, and permanence of the CO_2 storage. The Administrator may test the system itself, or require the applicant to perform any tests considered by the Administrator to be necessary to show the technology's effectiveness, safety, and ability to store captured CO_2 without release. The Administrator may grant conditional approval of a technology, the approval conditioned on monitoring and reporting of operations. The Administrator may also withdraw approval of the waiver on evidence of releases of CO_2 or other pollutants. The Administrator will provide notice to the public of any application under this provision, and provide public notice of any proposed action on a petition before the Administrator takes final action.

Recordkeeping and Reporting Requirements

§ 60.5865 What are my recordkeeping requirements?

(a) You must keep records of all information relied upon in support of any demonstration of plan components, plan requirements, supporting documentation, State measures, and the status of meeting the plan requirements defined in the plan for each interim step and the interim period. After 2029, States must keep records of all information relied upon in support of any continued demonstration that the final CO_2 emission performance rates or CO_2 emissions goals are being achieved.

(b) You must keep records of all data submitted by the owner or operator of each affected EGU that is used to determine compliance with each affected EGU emissions standard or requirements in an approved State plan, consistent with the affected EGU requirements listed in § 60.5860.

(c) If your State has a requirement for all hourly CO_2 emissions and net generation information to be used to calculate compliance with an annual emissions standard for affected EGUs, any information that is submitted by the owners or operators of affected EGUs to the EPA electronically pursuant to requirements in Part 75 meets the recordkeeping requirement of this section and you are not required to keep records of information that would be in duplicate of paragraph (b) of this section.

(d) You must keep records at a minimum for 10 years, for the interim period, and 5 years, for the final period, from the date the record is used to determine compliance with an emissions standard, plan requirement, CO_2 emission performance rate or CO_2 emissions goal. Each record must be in a form suitable and readily available for expeditious review.

§ 60.5870 What are my reporting and notification requirements?

(a) In lieu of the annual report required under § 60.25(e) and (f) of this part, you must report the information in paragraphs (b) through (f) of this section.

(b) You must submit a report covering each interim step within the interim period and each of the final 2-calendar year periods due no later than July 1 of the year following the end of the period. The interim period reporting starts with a report covering interim step 1 due no later than July 1, 2025. The final period reports start with a biennial report covering the first final reporting period (which is due by July 1, 2032), a 2-calendar year average of emissions or cumulative sum of emissions used to determine compliance with the final CO_2 emission performance rate or CO_2 emission goal (as applicable). The report must include the information in paragraphs (b)(1) through (4) of this section.

(1) The report must include the emissions performance achieved by all affected EGUs during the reporting period, consistent with the plan approach according to § 60.5745(a), and identification of whether each affected EGU is in compliance with its emission standard and whether the collective of all affected EGUs covered by the State are on schedule to meet the applicable CO_2 emission performance rate or emission goal during the performance periods and compliance periods, as specified in the plan.

(2) The report must include a comparison of the CO_2 emission performance rate or CO_2 emission goal identified in the State plan for the applicable interim step period versus the actual average, cumulative, or adjusted CO_2 emission performance (as applicable) achieved by all affected EGUs.

(i) For interim step 3, you do not need to include a comparison between the applicable interim step 3 CO_2 emission performance rate or emission goal; you must only submit the average, cumulative or adjusted CO_2 emission performance (as applicable) of your affected EGUs during that period in units of your applicable CO_2 emission performance rate or emission goal.

(3) The report must include all other required information, as specified in your State plan according to § 60.5740(a)(5).

(4) If applicable, the report must include a program review that your State has conducted that addresses all aspects of the administration of the State plan and overall program, including State evaluations and regulatory decisions regarding eligibility applications for ERC resources and M&V reports (and associated EM&V activities), and State issuance of ERCs. The program review must assess whether the program is being administered properly in accordance with the approved plan, whether reported annual MWh of generation and savings from qualified ERC resources are being properly quantified, verified, and reported in accordance with approved EM&V plans, and whether appropriate records are being maintained. The program review must also address determination of the eligibility of verifiers by the State and the conduct of independent verifiers, including the quality of verifier reviews.

(c) If your plan relies upon State measures, in lieu of or in addition to emission standards, then you must submit an annual report to the EPA in addition to the reports required under paragraph (b) of this section for the interim period. In the final period, you must submit biennial reports consistent with those required under paragraph (b) of this section. The annual reports in the interim period must be submitted no later than July 1 following the end of each calendar year starting with 2022.

The annual and biennial reports must include the information in paragraphs (c)(1) and (2) of this section for the preceding year or two years, as applicable.

(1) You must include in your report the status of implementation of federally enforceable emission standards (if applicable) and State measures.

(2) You must include information regarding the status of the periodic programmatic milestones to show progress in program implementation. The programmatic milestones with specific dates for achievement must be consistent with the State measures included in the State plan submittal.

(d) If your plan includes the requirement for emission standards on your affected EGUs, then you must submit a notification, if applicable, in the report required under paragraph (b) of this section to the EPA if your affected EGUs trigger corrective measures as described in § 60.5740(a)(2)(i). If corrective measures are required and were not previously submitted with your state plan, you must follow the requirements in § 60.5785 for revising your plan to implement the corrective measures.

(e) If your plan relies upon State measures, in lieu of or in addition to emission standards, than you must submit a notification as required under paragraphs (e)(1) and (2) of this section.

(1) You must submit a notification in the report required under paragraph (c) of this section to the EPA if at the end of the calendar year your State did not meet a programmatic milestone included in your plan submittal. This notification must detail the implementation of the backstop required in your plan to be fully in place within 18 months of the due date of the report required in paragraph (b) of this section. In addition, the notification must describe the steps taken by the State to inform the affected EGUs in its State that the backstop has been triggered.

(2) You must submit a notification in the report required under paragraph (b) of this section to the EPA if you trigger the backstop as described in § 60.5740(a)(3)(i). This notification must detail the steps that will be taken by you to implement the backstop so that it is fully in place within 18 months of the due date of the report required in paragraph (b) of this section. In addition, the notification must describe the steps taken by the State to inform the affected EGUs that the backstop has been triggered.

(f) You must include in your 2029 report (which is due by July 1, 2030) the calculation of average CO_2 emissions rate, cumulative sum of CO_2 emissions, or adjusted CO_2 emissions rate (as applicable) over the interim period and a comparison of those values to your interim CO_2 emission performance rate or emission goal. The calculated value must be in units consistent with the approach you set in your plan for the interim period.

(g) The notifications listed in paragraphs (g)(1) through (3) of this section are required for the reliability safety valve allowed in § 60.5785(e).

(1) As required under § 60.5785(e), you must submit an initial notification to the appropriate EPA regional office within 48 hours of an unforeseen, emergency situation. The initial notification must:

(i) Include a full description, to the extent that it is known, of the emergency situation that is being addressed;

(ii) Identify the affected EGU or EGUs that are required to run to assure reliability; and

(iii) Specify the modified emission standards at which the identified EGU or EGUs will operate.

(2) Within 7 days of the initial notification in § 60.5870(g)(1), the State must submit a second notification to the appropriate EPA regional office that documents the initial notification. If the State fails to submit this documentation on a timely basis, the EPA will notify the State, which must then notify the affected EGU(s) that they must operate or resume operations under the original approved State plan emission standards. This notification must include the following:

(i) A full description of the reliability concern and why an unforeseen, emergency situation that threatens reliability requires the affected EGU or EGUs to operate under modified emission standards from those originally required in the State plan including discussion of why the flexibilities provided under the state's plan are insufficient to address the concern;

(ii) A description of how the State is coordinating or will coordinate with relevant reliability coordinators and planning authorities to alleviate the problem in an expedited manner;

(iii) An indication of the maximum time that the State anticipates the affected EGU or EGUs will need to operate in a manner inconsistent with its or their obligations under the State's approved plan;

(iv) A written concurrence from the relevant reliability coordinator and/or planning authority confirming the existence of the imminent reliability threat and supporting the temporary modification request or an explanation of why this kind of concurrence cannot be provided;

(v) The modified emission standards or levels that the affected EGU or EGU will be operating at for the remainder of the 90-day period if it has changed from the initial notification; and

(vi) Information regarding any system-wide or other analysis of the reliability concern conducted by the relevant planning authority, if any.

(3) At least 7 days before the end of the 90-day reliability safety valve period, the State must notify the appropriate EPA regional office that either:

(i) The reliability concern has been addressed and the affected EGU or EGUs can resume meeting the original emission standards in the State plan approved prior to the short-term modification; or

(ii) There still is a serious, ongoing reliability issue that necessitates the affected EGU or EGUs to emit beyond the amount allowed under the State plan. In this case, the State must provide a notification to the EPA that it will be submitting a State plan revision according to paragraph § 60.5785(a) of this section to address the reliability issue. The notification must provide the date by which a revised State plan will be submitted to EPA and documentation of the ongoing emergency with a written concurrence from the relevant reliability coordinator and/or planning authority confirming the continuing urgent need for the affected EGU or EGUs to operate beyond the requirements of the State plan and that there is no other reasonable way of addressing the ongoing reliability emergency but for the affected EGU or EGUs to operate under an alternative emission standard than originally approved under the State plan. After the initial 90-day period, any excess emissions beyond what is authorized in the original approved State plan will count against the State's overall CO_2 emission goal or emission performance rate for affected EGUs.

§ 60.5875 How do I submit information required by these Emission Guidelines to the EPA?

(a) You must submit to the EPA the information required by these emission guidelines following the procedures in paragraphs (b) through (e) of this section.

(b) All negative declarations, State plan submittals, supporting materials that are part of a State plan submittal, any plan revisions, and all State reports required to be submitted to the EPA by the State plan must be reported through EPA's State Plan Electronic Collection

System (SPeCS). SPeCS is a web accessible electronic system accessed at the EPA's Central Data Exchange (CDX) (*http://www.epa.gov/cdx/*). States who claim that a State plan submittal or supporting documentation includes confidential business information (CBI) must submit that information 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: State and Local Programs Group, MD C539–01, 4930 Old Page Rd., Durham, NC 27703.

(c) Only a submittal by the Governor or the Governor's designee by an electronic submission through SPeCS shall be considered an official submittal to the EPA under this subpart. If the Governor wishes to designate another responsible official the authority to submit a State plan, the EPA must be notified via letter from the Governor prior to the September 6, 2016, deadline for plan submittal so that the official will have the ability to submit the initial or final plan submittal in the SPeCS. If the Governor has previously delegated authority to make CAA submittals on the Governor's behalf, a State may submit documentation of the delegation in lieu of a letter from the Governor. The letter or documentation must identify the designee to whom authority is being designated and must include the name and contact information for the designee and also identify the State plan preparers who will need access to SPeCS. A State may also submit the names of the State plan preparers via a separate letter prior to the designation letter from the Governor in order to expedite the State plan administrative process. Required contact information for the designee and preparers includes the person's title, organization and email address.

(d) The submission of the information by the authorized official must be in a non-editable format. In addition to the non-editable version all plan components designated as federally enforceable must also be submitted in an editable version. Following initial plan approval, States must provide the EPA with an editable copy of any submitted revision to existing approved federally enforceable plan components, including State plan backstop measures. The editable copy of any such submitted plan revision must indicate the changes made at the State level, if any, to the existing approved federally enforceable plan components, using a mechanism such as redline/strikethrough. These changes are not part of the State plan until formal approval by EPA.

(e) You must provide the EPA with non-editable and editable copies of any submitted revision to existing approved federally enforceable plan components, including State plan backstop measures. The editable copy of any such submitted plan revision must indicate the changes made at the State level, if any, to the existing approved federally enforceable plan components, using a mechanism such as redline/strikethrough. These changes are not part of the State plan until formal approval by EPA.

Definitions

§ 60.5880 What definitions apply to this subpart?

As used in this subpart, all terms not defined herein will have the meaning given them in the Clean Air Act and in subparts A, B, and TTTT, of this part.

Adjusted CO_2 Emission Rate Means

(1) For an affected EGU, the reported CO_2 emission rate of an affected EGU, adjusted as described in § 60.5790(c)(1) to reflect any ERCs used by an affected EGU to demonstrate compliance with its CO_2 emission standards; or

(2) For a State (or states in a multi-state plan) calculating a collective CO_2 emission rate achieved under the plan, the actual CO_2 emission rate during a plan reporting period of the affected EGUs subject to the rate specified in the plan, adjusted by the ERCs used for compliance by those EGUs (total CO_2 mass divided by the sum of the total MWh and ERCs).

Affected electric generating unit or *Affected EGU* means a steam generating unit, integrated gasification combined cycle (IGCC), or stationary combustion turbine that meets the relevant applicability conditions in section § 60.5845.

Allowance means an authorization for each specified unit of actual CO_2 emitted from an affected EGU or a facility during a specified period.

Allowance system means a control program under which the owner or operator of each affected EGU is required to hold an allowance for each specified unit of CO_2 emitted from that affected EGU or facility during a specified period and which limits the total amount of such allowances for a specified period and allows the transfer of such allowances.

Annual capacity factor means the ratio between the actual heat input to an EGU during a calendar year and the potential heat input to the EGU had it been operated for 8,760 hours during a calendar year at the base load rating.

Base load rating means the maximum amount of heat input (fuel) that an EGU can combust on a steady-state basis, as determined by the physical design and characteristics of the EGU at ISO conditions. For a stationary combustion turbine, *base load rating* includes the heat input from duct burners.

Biomass means biologically based material that is living or dead (*e.g.,* trees, crops, grasses, tree litter, roots) above and below ground, and available on a renewable or recurring basis. Materials that are biologically based include non-fossilized, biodegradable organic material originating from modern or contemporarily grown plants, animals, or microorganisms (including plants, products, byproducts and residues from agriculture, forestry, and related activities and industries, as well as the non-fossilized and biodegradable organic fractions of industrial and municipal wastes, including gases and liquids recovered from the decomposition of non-fossilized and biodegradable organic material).

CO_2 emission goal means a statewide rate-based CO_2 emission goal or mass-based CO_2 emission goal specified in § 60.5855.

Combined cycle unit means an electric generating unit that uses a stationary combustion turbine from which the heat from the turbine exhaust gases is recovered by a heat recovery steam generating unit to generate additional electricity.

Combined heat and power unit or *CHP unit, (*also known as ''cogeneration'') means an electric generating unit that uses a steam-generating unit or stationary combustion turbine to simultaneously produce both electric (or mechanical) and useful thermal output from the same primary energy source.

Compliance period means a discrete time period for an affected EGU to comply with either an emission standard or State measure.

Demand-side energy efficiency project means an installed piece of equipment or system, a modification of an existing piece of equipment or system, or a strategy intended to affect consumer electricity-use behavior, that results in a reduction in electricity use (in MWh) at an end-use facility, premises, or equipment connected to the electricity grid.

Derate means a decrease in the available capacity of an electric generating unit, due to a system or equipment modification or to discounting a portion of a generating unit's capacity for planning purposes.

Eligible resource means a resource that meets the requirements of § 60.5800(a).

Emission Rate Credit or ERC means a tradable compliance instrument that meets the requirements of § 60.5790(c).

EM&V plan means a plan that meets the requirements of § 60.5830.

ERC tracking system means a system for the issuance, surrender and retirement of ERCs that meets the requirements of § 60.5810.

Final period means the period that begins on January 1, 2030, and continues thereafter. The final period is comprised of final reporting periods, each of which may be no longer than two calendar years (with a calendar year beginning on January 1 and ending on December 31).

Final reporting period means an increment of plan performance within the final period, with each final reporting period being no longer than two calendar years (with a calendar year beginning on January 1 and ending on December 31), with the first final reporting period in the final period beginning on January 1, 2030, and ending no later than December 31, 2031.

Fossil fuel means natural gas, petroleum, coal, and any form of solid fuel, liquid fuel, or gaseous fuel derived from such material for the purpose of creating useful heat.

Heat recovery steam generating unit (HRSG) means a unit in which hot exhaust gases from the combustion turbine engine are routed in order to extract heat from the gases and generate useful output. Heat recovery steam generating units can be used with or without duct burners.

Independent verifier means a person (including any individual, corporation, partnership, or association) who has the appropriate technical and other qualifications to provide verification reports. The independent verifier must not have, or have had, any direct or indirect financial or other interest in the subject of its verification report or ERCs that could impact their impartiality in performing verification services.

Integrated gasification combined cycle facility or *IGCC* means a combined cycle facility that is designed to burn fuels containing 50 percent (by heat input) or more solid-derived fuel not meeting the definition of natural gas plus any integrated equipment that provides electricity or useful thermal output to either the affected facility or auxiliary equipment. The Administrator may waive the 50 percent solid-derived fuel requirement during periods of the gasification system construction, startup and commissioning, shutdown, or repair. No solid fuel is directly burned in the unit during operation.

Interim period means the period of eight calendar years from January 1, 2022, to December 31, 2029. The interim period is composed three interim steps, interim step 1, interim step 2, and interim step 3.

Interim step means an increment of plan performance within the interim period.

Interim step 1 means the period of three calendar years from January 1, 2022, to December 31, 2024.

Interim step 2 means the period of three calendar years from January 1, 2025, to December 31, 2027.

Interim step 3 means the period of two calendar years from January 1, 2028, to December 31, 2029.

ISO conditions means 288 Kelvin (15 °C), 60 percent relative humidity and 101.3 kilopascals pressure.

M&V report means a report that meets the requirements of § 60.5835.

Mechanical output means the useful mechanical energy that is not used to operate the affected facility, generate electricity and/or thermal output, or to enhance the performance of the affected facility. Mechanical energy measured in horsepower hour must be converted into MWh by multiplying it by 745.7 then dividing by 1,000,000.

Nameplate capacity means, starting from the initial installation, the maximum electrical generating output that a generator, prime mover, or other electric power production equipment under specific conditions designated by the manufacturer is capable of producing (in MWe, rounded to the nearest tenth) on a steady-state basis and during continuous operation (when not restricted by seasonal or other deratings) as of such installation as specified by the manufacturer of the equipment, or starting from the completion of any subsequent physical change resulting in an increase in the maximum electrical generating output that the equipment is capable of producing on a steady-state basis and during continuous operation (when not restricted by seasonal or other deratings), such increased maximum amount (in MWe, rounded to the nearest tenth) as of such completion as specified by the person conducting the physical change.

Natural gas means a fluid mixture of hydrocarbons (*e.g.,* methane, ethane, or propane), composed of at least 70 percent methane by volume or that has a gross calorific value between 35 and 41 megajoules (MJ) per dry standard cubic meter (950 and 1,100 Btu per dry standard cubic foot), that maintains a gaseous State under ISO conditions. In addition, natural gas contains 20.0 grains or less of total sulfur per 100 standard cubic feet. Finally, natural gas does not include the following gaseous fuels: Landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable sulfur content or heating value.

Net allowance export/import means a net transfer of CO_2 allowances during an interim step, the interim period, or a final reporting period which represents the net number of CO_2 allowances (issued by a State) that are transferred from the compliance accounts of affected EGUs in that state to the compliance accounts of affected EGUs in another State. This net transfer is determined based on compliance account holdings at the end of the plan performance period. Compliance account holdings, as used here, refer to the number of CO_2 allowances surrendered for compliance during a plan performance period, as well as any remaining CO_2 allowances held in a compliance account as of the end of a plan performance period.

Net electric output means the amount of gross generation the generator(s) produce (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)), as measured at the generator terminals, less the electricity used to operate the plant (*i.e.,* auxiliary loads); such uses include fuel handling equipment, pumps, fans, pollution control equipment, other electricity needs, and transformer losses as measured at the transmission side of the step up transformer (*e.g.,* the point of sale).

Net energy output means:

(1) The net electric or mechanical output from the affected facility, plus 100 percent of the useful thermal output measured relative to SATP conditions that is not used to generate additional electric or mechanical output or to enhance the performance of the unit (*e.g.,* steam delivered to an industrial process for a heating application).

(2) For combined heat and power facilities where at least 20.0 percent of the total gross or net energy output consists of electric or direct mechanical output and at least 20.0 percent of the total gross or net energy output consists of useful thermal output on a 12-operating month rolling average basis, the net electric or mechanical output from the affected EGU divided by 0.95, plus 100 percent of the useful thermal output; (*e.g.,* steam delivered to an industrial process for a heating application).

Programmatic milestone means the implementation of measures necessary for plan progress, including specific dates associated with such implementation. Prior to January 1, 2022, programmatic milestones are applicable to all state plan approaches and measures. Subsequent to January 1, 2022, programmatic milestones are applicable to state measures.

Qualified biomass means a biomass feedstock that is demonstrated as a method to control increases of CO_2 levels in the atmosphere.

Standard ambient temperature and pressure (SATP) conditions means 298.15 Kelvin (25 °C, 77 °F)) and 100.0 kilopascals (14.504 psi, 0.987 atm) pressure. The enthalpy of water at SATP conditions is 50 Btu/lb.

State agent means an entity acting on behalf of the State, with the legal authority of the State.

State measures means measures that are adopted, implemented, and enforced as a matter of State law. Such measures are enforceable only per State law, and are not included in and codified as part of the federally enforceable State plan.

Stationary combustion turbine means all equipment, including but not limited to the turbine engine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), heat recovery system, fuel compressor, heater, and/or pump, post-combustion emissions control technology, and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any combined cycle combustion turbine, and any combined heat and power combustion turbine based system plus any integrated equipment that provides electricity or useful thermal output to the combustion turbine engine, heat recovery system or auxiliary equipment. Stationary means that the combustion turbine is not self-propelled or intended to be propelled while performing its function. It may, however, be mounted on a vehicle for portability. If a stationary combustion turbine burns any solid fuel directly it is considered a steam generating unit.

Steam generating unit means any furnace, boiler, or other device used for combusting fuel and producing steam (nuclear steam generators are not included) plus any integrated equipment that provides electricity or useful thermal output to the affected facility or auxiliary equipment.

Uprate means an increase in available electric generating unit power capacity due to a system or equipment modification.

Useful thermal output means the thermal energy made available for use in any heating application (*e.g.,* steam delivered to an industrial process for a heating application, including thermal cooling applications) that is not used for electric generation, mechanical output at the affected EGU, to directly enhance the performance of the affected EGU (*e.g.,* economizer output is not useful thermal output, but thermal energy used to reduce fuel moisture is considered useful thermal output), or to supply energy to a pollution control device at the affected EGU. Useful thermal output for affected EGU(s) with no condensate return (or other thermal energy input to the affected EGU(s)) or where measuring the energy in the condensate (or other thermal energy input to the affected EGU(s)) would not meaningfully impact the emission rate calculation is measured against the energy in the thermal output at SATP conditions. Affected EGU(s) with meaningful energy in the condensate return (or other thermal energy input to the affected EGU) must measure the energy in the condensate and subtract that energy relative to SATP conditions from the measured thermal output.

Valid data means quality-assured data generated by continuous monitoring systems that are installed, operated, and maintained according to part 75 of this chapter. For CEMS, the initial certification requirements in § 75.20 of this chapter and appendix A to part 75 of this chapter must be met before quality-assured data are reported under this subpart; for on-going quality assurance, the daily, quarterly, and semiannual/annual test requirements in sections 2.1, 2.2, and 2.3 of appendix B to part 75 of this chapter must be met and the data validation criteria in sections 2.1.5, 2.2.3, and 2.3.2 of appendix B to part 75 of this chapter apply. For fuel flow meters, the initial certification requirements in section 2.1.5 of appendix D to part 75 of this chapter must be met before quality-assured data are reported under this subpart (except for qualifying commercial billing meters under section 2.1.4.2 of appendix D), and for on-going quality assurance, the provisions in section 2.1.6 of appendix D to part 75 of this chapter apply (except for qualifying commercial billing meters).

Waste-to-Energy means a process or unit (*e.g.,* solid waste incineration unit) that recovers energy from the conversion or combustion of waste stream materials, such as municipal solid waste, to generate electricity and/or heat.

TABLE 1 TO SUBPART UUUU OF PART 60—CO_2 EMISSION PERFORMANCE RATES

[Pounds of CO_2 per net MWh]

Affected EGU	Interim rate	Final rate
Steam generating unit or integrated gasification combined cycle (IGCC)	1,534	1,305
Stationary combustion turbine	832	771

TABLE 2 TO SUBPART UUUU OF PART 60—STATEWIDE RATE-BASED CO_2 EMISSION GOALS

[Pounds of CO_2 per net MWh]

State	Interim emission goal	Final emission goal
Alabama	1,157	1,018
Arizona	1,173	1,031
Arkansas	1,304	1,130
California	907	828
Colorado	1,362	1,174
Connecticut	852	786
Delaware	1,023	916
Florida	1,026	919
Georgia	1,198	1,049
Idaho	832	771
Illinois	1,456	1,245

TABLE 2 TO SUBPART UUUU OF PART 60—STATEWIDE RATE-BASED CO_2 EMISSION GOALS—Continued

[Pounds of CO_2 per net MWh]

State	Interim emission goal	Final emission goal
Indiana	1,451	1,242
Iowa	1,505	1,283
Kansas	1,519	1,293
Kentucky	1,509	1,286
Lands of the Fort Mojave Tribe	832	771
Lands of the Navajo Nation	1,534	1,305
Lands of the Uintah and Ouray Reservation	1,534	1,305
Louisiana	1,293	1,121
Maine	842	779
Maryland	1,510	1,287
Massachusetts	902	824
Michigan	1,355	1,169
Minnesota	1,414	1,213
Mississippi	1,061	945
Missouri	1,490	1,272
Montana	1,534	1,305
Nebraska	1,522	1,296
Nevada	942	855
New Hampshire	947	858
New Jersey	885	812
New Mexico	1,325	1,146
New York	1,025	918
North Carolina	1,311	1,136
North Dakota	1,534	1,305
Ohio	1,383	1,190
Oklahoma	1,223	1,068
Oregon	964	871
Pennsylvania	1,258	1,095
Rhode Island	832	771
South Carolina	1,338	1,156
South Dakota	1,352	1,167
Tennessee	1,411	1,211
Texas	1,188	1,042
Utah	1,368	1,179
Virginia	1,047	934
Washington	1,111	983
West Virginia	1,534	1,305
Wisconsin	1,364	1,176
Wyoming	1,526	1,299

TABLE 3 TO SUBPART UUUU OF PART 60—STATEWIDE MASS-BASED CO_2 EMISSION GOALS

[Short tons of CO_2]

State	Interim emission goal (2022–2029)	Final emission goals (2 year blocks starting with 2030–2031)
Alabama	497,682,304	113,760,948
Arizona	264,495,976	60,341,500
Arkansas	269,466,064	60,645,264
California	408,216,600	96,820,240
Colorado	267,103,064	59,800,794
Connecticut	57,902,920	13,883,046
Delaware	40,502,952	9,423,650
Florida	903,877,832	210,189,408
Georgia	407,408,672	92,693,692
Idaho	12,401,136	2,985,712
Illinois	598,407,008	132,954,314
Indiana	684,936,520	152,227,670
Iowa	226,035,288	50,036,272
Kansas	198,874,664	43,981,652
Kentucky	570,502,416	126,252,242
Lands of the Fort Mojave Tribe	4,888,824	1,177,038
Lands of the Navajo Nation	196,462,344	43,401,174
Lands of the Uintah and Ouray Reservation	20,491,560	4,526,862
Louisiana	314,482,512	70,854,046
Maine	17,265,472	4,147,884
Maryland	129,675,168	28,695,256
Massachusetts	101,981,416	24,209,494
Michigan	424,457,200	95,088,128

TABLE 3 TO SUBPART UUUU OF PART 60—STATEWIDE MASS-BASED CO_2 EMISSION GOALS—Continued

[Short tons of CO_2]

State	Interim emission goal (2022–2029)	Final emission goals (2 year blocks starting with 2030–2031)
Minnesota	203,468,736	45,356,736
Missouri	500,555,464	110,925,768
Mississippi	218,706,504	50,608,674
Montana	102,330,640	22,606,214
Nebraska	165,292,128	36,545,478
Nevada	114,752,736	27,047,168
New Hampshire	33,947,936	7,995,158
New Jersey	139,411,048	33,199,490
New Mexico	110,524,488	24,825,204
New York	268,762,632	62,514,858
North Carolina	455,888,200	102,532,468
North Dakota	189,062,568	41,766,464
Ohio	660,212,104	147,539,612
Oklahoma	356,882,656	80,976,398
Oregon	69,145,312	16,237,308
Pennsylvania	794,646,616	179,644,616
Rhode Island	29,259,080	7,044,450
South Carolina	231,756,984	51,997,936
South Dakota	31,591,600	7,078,962
Tennessee	254,278,880	56,696,792
Texas	1,664,726,728	379,177,684
Utah	212,531,040	47,556,386
Virginia	236,640,576	54,866,222
Washington	93,437,656	21,478,344
West Virginia	464,664,712	102,650,684
Wisconsin	250,066,848	55,973,976
Wyoming	286,240,416	63,268,824

TABLE 4 TO SUBPART UUUU OF PART 60— STATEWIDE MASS-BASED CO_2 GOALS PLUS NEW SOURCE CO_2 EMISSION COMPLEMENT

[Short tons of CO_2]

State	Interim emission goal (2022–2029)	Final emission goals (2 year blocks starting with 2030–2031)
Alabama	504,534,496	115,272,348
Arizona	275,895,952	64,760,392
Arkansas	272,756,576	61,371,058
California	430,988,824	105,647,270
Colorado	277,022,392	63,645,748
Connecticut	58,986,192	14,121,986
Delaware	41,133,688	9,562,772
Florida	917,904,040	213,283,190
Georgia	412,826,944	93,888,808
Idaho	13,155,256	3,278,026
Illinois	604,953,792	134,398,348
Indiana	692,451,256	153,885,208
Iowa	228,426,760	50,563,762
Kansas	200,960,120	44,441,644
Kentucky	576,522,048	127,580,002
Lands of the Fort Mojave Tribe	5,186,112	1,292,276
Lands of the Navajo Nation	202,938,832	45,911,608
Lands of the Uintah and Ouray Reservation	21,167,080	4,788,708
Louisiana	318,356,976	71,708,642
Maine	17,592,128	4,219,936
Maryland	131,042,600	28,996,872
Massachusetts	103,782,424	24,606,744
Michigan	429,446,408	96,188,604
Minnesota	205,761,008	45,862,346
Mississippi	221,990,024	51,332,926
Missouri	505,904,560	112,105,626
Montana	105,704,024	23,913,816
Nebraska	167,021,320	36,926,888
Nevada	120,916,064	29,436,214
New Hampshire	34,519,280	8,121,182
New Jersey	141,919,248	33,752,728
New Mexico	114,741,592	26,459,850

TABLE 4 TO SUBPART UUUU OF PART 60— STATEWIDE MASS-BASED CO_2 GOALS PLUS NEW SOURCE CO_2 EMISSION COMPLEMENT—Continued

[Short tons of CO_2]

State	Interim emission goal (2022–2029)	Final emission goals (2 year blocks starting with 2030–2031)
New York	272,940,440	63,436,364
North Carolina	461,424,928	103,753,712
North Dakota	191,025,152	42,199,354
Ohio	667,812,080	149,215,950
Oklahoma	361,531,056	82,001,704
Oregon	72,774,608	17,644,106
Pennsylvania	804,705,296	181,863,274
Rhode Island	29,819,360	7,168,032
South Carolina	234,516,064	52,606,510
South Dakota	31,963,696	7,161,036
Tennessee	257,149,584	57,329,988
Texas	1,707,356,792	396,210,498
Utah	220,386,616	50,601,386
Virginia	240,240,880	55,660,348
Washington	97,691,736	23,127,324
West Virginia	469,488,232	103,714,614
Wisconsin	252,985,576	56,617,764
Wyoming	295,724,848	66,945,204

[FR Doc. 2015–22842 Filed 10–22–15; 8:45 am]

BILLING CODE 6560–50–P

FEDERAL REGISTER

Vol. 80 Friday,
No. 205 October 23, 2015

Part IV

Environmental Protection Agency

40 CFR Parts 60, 62, and 78
Federal Plan Requirements for Greenhouse Gas Emissions From Electric Utility Generating Units Constructed on or Before January 8, 2014; Model Trading Rules; Amendments to Framework Regulations; Proposed Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 60, 62, and 78

[EPA–HQ–OAR–2015–0199; FRL 9930–67–OAR]

RIN 2060–AS47

Federal Plan Requirements for Greenhouse Gas Emissions From Electric Utility Generating Units Constructed on or Before January 8, 2014; Model Trading Rules; Amendments to Framework Regulations

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: In this action, the Environmental Protection Agency (EPA) is proposing a federal plan to implement the greenhouse gas (GHG) emission guidelines (EGs) for existing fossil fuel-fired electric generating units (EGUs) under the Clean Air Act (CAA). The EGs were proposed in June 2014 and finalized on August 3, 2015 as the Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units (also known as the Clean Power Plan or EGs). This proposal presents two approaches to a federal plan for states and other jurisdictions that do not submit an approvable plan to the EPA: a rate-based emission trading program and a mass-based emission trading program. These proposals also constitute proposed model trading rules that states can adopt or tailor for implementation of the final EGs. The federal plan is an important measure to ensure that congressionally mandated emission standards under the authority of the CAA are implemented. The proposed federal plan is related to but separate from the final EGs. The final EGs establish the best system of emission reduction (BSER) for applicable fossil fuel-fired EGUs in the form of a carbon dioxide (CO_2) emission performance rate for steam-fired EGUs and a CO_2 emission performance rate for natural gas-fired combined cycle (NGCC) units, and provide guidance and criteria for the development of approvable state plans. The purpose of the proposed federal plan is to establish requirements directly applicable to a state's affected EGUs that meet these emission performance levels, or the equivalent statewide goal, in order to achieve reductions in CO_2 emissions in the case where a state or other jurisdiction does not submit an approvable plan. The stringency of the emission performance levels established in the final EGs will be the same whether implemented through a state plan or a federal plan. The EPA is also proposing enhancements to the CAA section 111(d) framework regulations related to the process and timing for state plan submissions and EPA actions. The EPA intends to finalize both the rate-based and mass-based model trading rules in summer 2016.

DATES: *Comments.* Comments must be received on or before January 21, 2016.

Public Hearing. The EPA will hold public hearings on the proposal. Details will be announced in a separate **Federal Register** document.

ADDRESSES: Submit your comments, identified by Docket ID No. EPA–HQ–OAR–2015–0199, 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 on the federal plan requirements proposed rule to Docket ID No. EPA–HQ–OAR–2015–0199. The EPA's policy is that all comments received will be included in the public docket 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 disk or CD–ROM you submit. If the EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, the EPA may not be able to consider your comment. Electronic files should avoid the use of special characters, any form of encryption and be free of any defects or viruses.

Docket: The EPA has established a docket for this action under Docket ID No. EPA–HQ–OAR–2015–0199. The EPA has previously established a docket for the January 8, 2014, Clean Power Plan proposal under Docket ID No. EPA–HQ–OAR–2009–0559. 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 form. Publicly available docket materials are available either electronically at *http://www.regulations.gov* or in hard copy at the EPA Docket Center EPA/DC, 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 holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the EPA Docket Center is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: Ms. Toni Jones, Fuels and Incineration Group, Sector Policies and Programs Division (E143–05), Environmental Protection Agency, Research Triangle Park, North Carolina 27711; telephone number: (919) 541–0316; fax number: (919) 541–3470; email address: *jones.toni@epa.gov.*

SUPPLEMENTARY INFORMATION:

Acronyms and Abbreviations. The following acronyms and abbreviations are used in this document.

ANSI American National Standards Institute
ARP Acid Rain Program

ATCS Allowance Tracking and Compliance System
BSER Best system of emission reduction
CAA Clean Air Act
CAIR Clean Air Interstate Rule
CARB California Air Resources Board
CBI Confidential Business Information
CEIP Clean Energy Incentive Program
CEMS Continuous emissions monitoring system
CFCs Chlorofluorocarbons
CISWI Commercial Industrial Solid Waste Incinerators
CFR Code of Federal Regulations
CHP Combined heat and power
CO_2 Carbon dioxide
CO_2e Carbon dioxide equivalent
CSAPR Cross-state Air Pollution Rule
DOE U.S. Department of Energy
DOI U.S. Department of the Interior
DOL U.S. Department of Labor
DS–EE Demand-Side Energy Efficiency
EE Energy efficiency
EGs Emission Guidelines
EGU Electric generating unit
EIA Energy Information Administration
EJ Environmental justice
EM&V Evaluation, measurement, and verification
EPA Environmental Protection Agency
EO Executive Order
ERC Emission rate credit
FERC Federal Energy Regulatory Commission
FIP Federal implementation plan
FR Federal Register
GHG Greenhouse gas
GHGRP Greenhouse Gas Reporting Program
GJ/h Gigajoule per hour
HAP Hazardous air pollutants
ICR Information collection request
IGCC Integrated gasification combined cycle facility
IPM Integrated Planning Model
IPCC Intergovernmental Panel on Climate Change
ISO/RTO Independent System Operator/ Regional Transmission Organization
lbs Pounds
LML Lowest measured $PM_{2.5}$ levels
MATS Mercury and Air Toxics Standards
M&V Measurement and verification
MMBtu/h Million British Thermal units per hour
MSW Municipal solid waste
MW Megawatts
MWh Megawatt-hours
NAAQS National Ambient Air Quality Standards
NAICS North American Industrial Classification System
NERC North American Electric Reliability Corporation
NGCC Natural gas combined cycle
NSPS New source performance standards
NSR New Source Review
NTTAA National Technology Transfer and Advancement Act
NODA Notice of data availability
NO_X Nitrogen oxides
OAP Office of Atmospheric Programs
OAQPS Office of Air Quality Planning and Standards
PRA Paperwork Reduction Act
PSD Prevention of significant deterioration
PUC Public Utility Commission
RCT Randomized control trials
RE Renewable energy
REC Renewable Energy Certificate
RFA Regulatory Flexibility Act
RGGI Regional Greenhouse Gas Initiative
RIA Regulatory impact analysis
RPS Renewable Portfolio Standard
SCT Stationary combustion turbine
SGU Steam generating unit
SIP State implementation plan
SO_2 Sulfur dioxide
TRM Technical Reference Manual
TSD Technical support document
The Court U.S. Court of Appeals for the District of Columbia Circuit
TTN Technology Transfer Network
UMRA Unfunded Mandates Reform Act
UNFCCC United Nations Framework Convention on Climate Change
U.S. United States
WWW World Wide Web

Organization of This Document. The following outline is provided to aid in locating information in this preamble.

I. General Information

A. Executive Summary

In the CAA, Congress created a partnership between the EPA and the states. Under section 111(d) of the CAA, the EPA establishes emission performance levels based on its determination of the BSER for existing sources of air pollution and provides guidelines for state plans to apply standards of performance to their sources that meet the BSER level of performance. The EPA promulgated EGs under CAA section 111(d) which set source-level CO_2 emission performance rates for the EGUs at certain large fossil fuel-fired power plants (''affected EGUs''). States then apply these EGs to their sources in developing state plans to achieve these emission performance levels for EPA approval, or initial submittals, by September 6, 2016. The amount of reductions in CO_2 that the EPA determined to be achievable for these sources is based on its determination of what constitutes the BSER. This determination is finalized in the EGs, which are designed to maximize the flexibility of both states and affected EGUs in meeting CO_2 emissions performance rates. While states may impose the emission rates directly on their affected EGUs, states also have the option of submitting more tailored plans that meet state-specific emissions goals. The EGs also provide flexibility by allowing for emissions trading and multi-state compliance options.

While it has been the EPA's longstanding view that the statute identifies states as the preferred implementers of CAA programs, the agency makes clear in the EGs that states cannot and will not be penalized for failing to participate in this program. However, if a state does not submit an approvable plan under section 111(d) of the CAA, the EPA will develop, implement, and enforce a federal plan to reduce CO_2 from the fossil fuel-fired power plants in that state. This is wholly consistent with the ''cooperative federalism'' structure of the CAA and many of our nation's other environmental laws. In addition, we have heard from states and other stakeholders that it would be helpful for the agency to present model designs for state plans, and a federal plan would be an appropriate means of doing that.

Accordingly, the EPA proposes a federal plan under section 111(d) of the CAA for the control of CO_2, a GHG pollutant, from certain emitting fossil fuel-fired power plants, in the event that some states do not adopt their own plans. Specifically, the EPA is proposing approaches in the form of mass- and rate-based trading options that provide flexibility in implementing emission standards for a state's affected EGUs. Both proposed approaches to the federal plan would require affected EGUs to meet emission standards set using the CO_2 emission performance rates in the EGs. The federal plan will achieve the same levels of emissions performance as required of state plans under the EGs. The EPA will promulgate a final federal plan for only the affected EGUs in states that the EPA determines did not submit an approvable plan.

At the same time, these two proposed options offer states model trading rules that the states can follow in developing their own plans in order to capitalize on the flexibility built into the final EGs. Thus, this document proposes four discrete actions: (1) A rate-based federal plan for each state with affected EGUs; (2) a mass-based federal plan for each state with affected EGUs; (3) a rate-based model trading rule for potential use by any state; and (4) a mass-based model trading rule for potential use by any state. The regulatory text of each federal plan and corresponding model trading rule is identical, except as indicated otherwise within the text of the model rule (for instance, the EPA is providing model rule text for states to use related to the crediting of a broader set of clean energy resources than is being proposed in the federal plan).

The EPA intends to finalize both the rate-based and mass-based model trading rules in summer 2016. The EPA will finalize a federal plan for only a given state in the event that the state does not submit an approvable plan by the deadlines specified in the final EGs and the EPA takes action finding that the state has failed to submit a plan, or disapproving a submitted plan because it does not meet the requirements of the EGs.[1] Indeed, states may simply choose to accept a federal plan for their sources rather than undertake the development of a plan of their own by not submitting a state plan. Under this proposed rule, a federal plan promulgated for a particular state would take the form of either the mass-based model trading rule or the rate-based model trading rule. The EPA currently intends to finalize a single approach (*i.e.,* either the mass-based or rate-based approach) for every state in which it promulgates a federal plan, given the benefits of a broad trading program, as discussed in

[1] For simplicity, at times this document may refer to the co-proposed federal plans as ''the federal plan.'' (It may refer to the model trading rules in the singular as well.) Even though the singular is used, this term is meant to encompass both the rate-based approach and the mass-based approach. The use of the singular when referring to this proposed federal plan also is intended to encompass all state-specific federal plans. In other words, the EPA intends to finalize ''the federal plan'' as a series of state-specific ''federal plans.'' This is consistent with the agency's prior practice in other multi-state trading programs such as the NO_X Budget Trading Program, the Clean Air Interstate Rule (CAIR), and the Cross-State Air Pollution Rule (CSAPR), where a single rule promulgated multiple FIPs.

section I.B of this preamble. We invite comment on which approach, *i.e.,* either mass-based or rate-based trading, should be selected if we opt to finalize a single approach.

It is the EPA's intention to give the states as much opportunity as possible to set their own course for carrying out the EGs. Even where a federal plan is put in place for a particular state, that state will still be able to submit a plan, which, upon approval, will allow the state and its sources to exit the federal plan. In addition, as discussed in section VI.A of this preamble, states may take delegation of administrative aspects of the federal plan in order to become the primary implementers. And as discussed in sections V.E and VII.A of this preamble, states may submit partial state plans in order to take over the implementation of a portion of a federal plan. For instance, in a mass-based trading program, the agency proposes to allow states to submit partial state plans to replace the federal plan allowance-distribution provisions with their own allowance-distribution provisions, similar to the approach we have taken in prior trading programs. Finally, even in states in which the affected EGUs are operating under a federal plan, the agency recognizes that states may adopt complementary measures outside of CAA programming to facilitate compliance and lower costs that could benefit power generators and consumers, directly or indirectly.

A state program that adheres to the model trading rule provisions specified in this rulemaking would be presumptively approvable. States may submit means of meeting the EGs' requirements that differ from the model trading rule provisions, so long as the state demonstrates to the EPA's satisfaction in the state plan submittal that such alternative means of addressing requirements are at least as stringent as the presumptively approvable approach described here.[2] Additionally, there are stand-alone portions of the model trading rules, such as the evaluation, measurement, and verification (EM&V) procedures, that would be approvable even if a state adopted an approach that differs from the federal plan. The model trading rules serve as a mechanism to facilitate larger trading markets since consistency with the federal plan allows trading across both the state and federal programs. The EPA expects a larger trading region is likely to result in lower overall costs. These and other aspects of the model trading rules and federal plan provide additional support for this rule as proposed. Thus, the proposed rule would ensure that congressionally mandated emission standards under authority of section 111 of the CAA are implemented, either by the states in the first instance, or by the EPA where needed.

The agency is proposing a finding that it is necessary or appropriate to implement a CAA section 111(d) federal plan for the affected EGUs located in Indian country. CO_2 emission performance rates for these facilities were finalized in the EGs. Tribes generally may seek ''treatment as a state'' (TAS) and submit a tribal plan to implement CAA programs, including programs under CAA section 111(d), and this proposed finding does not preclude tribes from doing that. However, tribes are not subject to the deadlines applicable to state action under the EGs and in the absence of a federal plan, CO_2 emissions from these EGUs could go unregulated. Therefore, as discussed in section VI.D of this preamble, we are proposing a necessary or appropriate finding.

This document also proposes certain enhancements to the process and timing for state submittals and EPA action in the CAA section 111(d) framework regulations of 40 CFR part 60, subpart B (these proposals are not a part of the federal plan or model trading rules). These changes, if finalized, would be applicable under the Clean Power Plan and other CAA section 111(d) rules. These changes clarify the availability of certain procedural mechanisms similar to those available under CAA section 110 (such as calls for plan revisions and the availability of ''conditional approvals,'' etc.). They also extend the deadlines for EPA action, in part to conform with the timelines in the EGs. These changes do not alter the timelines for state action under the EGs and do not alter the submission requirements established in the EGs. Finally, the agency proposes to clarify and request comment on an interpretive issue raised in the Clean Power Plan proposal regarding whether a reconstruction or modification that is subject to a CAA section 111(b) standard moves an existing source out of a CAA section 111(d) program. These proposed changes are discussed in section VII of this preamble. The agency intends to finalize these changes earlier than the finalization of the model trading rules.

In proposing a federal plan, the EPA considered a variety of potential impacts that its action might have on the environment, on businesses, particularly in the energy sector, and on the reliability of the electrical grid. The agency gave extensive consideration to impacts on vulnerable communities, particularly low-income communities, communities of color, and indigenous communities. These considerations are discussed in sections III, VIII, IX, and X of this preamble.

The agency convened a Small Business Advocacy Review Panel under the Regulatory Flexibility Act and has completed an Initial Regulatory Flexibility Analysis (IRFA). Various recommendations from the Panel are found reflected throughout this proposal. In section X of this preamble, the agency explains how it has conducted or intends to conduct all other statutory or executive order (EO) reviews that apply to this proposed action. The EPA also explains in this document how it proposes to take into consideration the ''remaining useful lives'' of affected EGUs in the design of the proposed federal plan, as discussed below in section III.G of this preamble.

The agency considered the impacts this action could have on the electricity grid and developed options for compliance that are cost-effective and that provide substantial flexibility for the affected EGUs that will accommodate the parties charged with maintaining the reliability of electrical power. A key feature of the proposed federal plan and model trading rule is that the flexibility inherent in both of the two approaches (*i.e.,* rate-based or mass-based trading) enables the EPA and the states to create a level of flexibility for affected EGUs that allows owners and operators to determine the best way to achieve emission reductions, at the EGU-, state-, multi-state-, regional-, or national level. As a result, compliance strategies can mirror, or be integrated with, the ongoing operations of the current electricity grid as it continues to serve its primary critical function of ensuring an uninterrupted supply of affordable and reliable electricity. This flexibility is especially valuable whenever the need to address specific reliability concerns arises. It allows owners and operators of reliability-critical EGUs to continue to meet their compliance obligations while operating to maintain electric reliability.

The EPA outlined and initiated the Clean Energy Incentive Program (CEIP) in the final EGs (see section VIII of the final EGs). The program is designed to

[2] For example, in the context of a mass- or rate-based trading program, a state may submit a plan with alternative components other than those described, so long as the program includes each of the requirements and the state satisfactorily demonstrates in the state plan submittal that such alternative means of addressing the requirements are as stringent as the presumptively approvable approach as described, and therefore provide for the implementation of the state plan's emission standards.

incentivize investment in certain types of renewable energy (RE) projects, as well as demand-side energy efficiency (EE) projects implemented in low-income communities, that generate MWh or reduce end-use energy demand during 2020 and/or 2021. The EPA proposes to apply the CEIP in all states subject to either a rate-based or mass-based federal plan.

We also reviewed impacts that this action could have on the environment and the need to ensure environmental integrity of the program as well as avoid unintended environmental impacts. We took measures to ensure that the reductions in carbon emissions this plan will achieve are real, and not just apparent. As in the EGs, in both the rate- and mass-based approaches, the EPA has incorporated components to address the concern that the dynamics of either a rate- or mass-based trading program could incentivize shifting generation from existing units in ways that would result in more CO_2 emissions than would otherwise be expected, or that undermine the purpose of the CAA section 111(d) program.

We considered whether compliance choices under a federal plan could lead to an unintended concentration of other air pollutants in certain overburdened communities, particularly low-income communities and communities of color. As discussed below, our analysis shows why we do not expect this to occur at any significant level. In general, as in the EGs, we anticipate that the federal plan will result in overall reductions of co-pollutants, in addition to reductions in CO_2, with corresponding co-benefits to public health. We also reviewed whether this action could trigger an obligation to consult with other agencies responsible for implementing the Endangered Species Act, and propose to conclude that it will not.

In the final EGs, the EPA emphasized the importance of state actions to ensure that in developing their respective compliance plans the states addressed the concerns and priorities of vulnerable communities. In the process of developing a final federal plan, the EPA will take actions to address those concerns as well. In addition to the public hearings that the EPA will be holding for all members of the American public on this proposed rulemaking, we will also be conducting a national webinar and outreach meeting(s) in all ten regions on this proposed rulemaking for communities. The goal of these outreach activities is to provide communities with the information they need to understand how the proposed rulemaking will potentially impact their respective communities. At the same time, this information will be useful in helping communities engage the EPA during our comment period, as well as with their states during the state plan development process. We will also be providing other outreach and support activities for vulnerable communities, which are outlined in the community and environmental justice (EJ) considerations in section IX.B of this preamble.

B. Organization and Approach for This Proposed Rule

In this action, the EPA is proposing a federal plan to implement the Clean Power Plan EGs for affected fossil fuel-fired EGUs operating in states that do not have approved state plans. Specifically, the EPA is co-proposing two different approaches to a federal plan to implement the Clean Power Plan EGs—a rate-based trading approach and a mass-based trading approach. While establishing emission standards for affected EGUs that would be directly enforceable against the owners and operators of the source, both approaches would grant EGUs substantial flexibility in meeting their compliance obligations. For this reason, among others, these proposed approaches also serve as two proposed model trading rules that states may adopt or tailor in designing their own plans.

The EGs provide that states have until September 6, 2016 (or upon making an initial submittal, until September 6, 2018) to submit state plans, and the EPA does not intend to finalize and implement the federal plan for any states prior to the agency's action of determining a failure to submit a state plan or disapproving a state plan. At the same time, in order to support states' consideration of adoption of one of the model trading rules as an approvable state plan, the agency intends to finalize either or both model rule options presented in this proposed rule by summer 2016, prior to the deadline for state submittals.

The EPA currently intends to finalize a single approach—*i.e.,* either a rate-based or a mass-based approach—in all promulgated federal plans for particular states in order to enhance the consistency of the federal trading program, achieve economies of scale through a single, broad trading program, ensure efficient administration of the program, and simplify compliance planning for affected EGUs. The EPA recognizes that the mass-based trading approach would be more straightforward to implement compared to the rate-based trading approach, both for industry and for the implementing agency. The EPA, industry, and many state agencies have extensive knowledge of and experience with mass-based trading programs. The EPA has more than two decades of experience implementing federally-administered mass-based emissions budget trading programs including the Acid Rain Program (ARP) sulfur dioxide (SO_2) trading program, the Nitrogen Oxides (NO_X) Budget Trading Program, CAIR, and CSAPR. The tracking system infrastructure exists and is proven effective for implementing such programs. The EPA requests comment on which approach—mass-based or rate-based trading—is preferred for the federal plan. Some stakeholders have suggested there could be utility in the availability of both approaches based on the unique circumstances of particular states. The EPA recognizes that it remains potentially possible to finalize a different approach to a federal plan in some circumstances, but believes that in general, and consistent with prior federal trading programs such as CSAPR, creating a single, broad program has the most advantages.

The stringency of the proposed federal plan is the same as the CO_2 emission performance rates established for affected EGUs in the EGs. As explained in the final EGs, the EPA determined the CO_2 emission performance rates through the application of the BSER. In the EGs, the EPA has taken final action on the BSER for CO_2 emissions from existing fossil fuel-fired EGUs. Any comments on this proposed rule relating to the BSER, its stringency, rationale, or legal basis, will not be considered as, by definition, they will be beyond the scope of this action.[3]

1. The Rate-Based Approach

In the first approach, the EPA would implement a rate-based emissions trading program. In a rate-based program, affected EGUs must meet an emission standard, derived from the EGs, expressed as a rate of pounds of CO_2 per megawatt hour (lbs/MWh). If sources emit above their assigned rate, they must acquire a sufficient number of emission rate credits (ERC), each representing a zero-emitting megawatt hour (MWh), to bring their rate of emissions into compliance. Emission rate credits (ERCs) may be generated by affected EGUs or by other entities that supply zero- or low-emitting electricity resources to the grid through an approval and recognition process that

[3] The agency recognizes that the ''remaining useful lives'' of facilities subject to a CAA section 111(d) federal plan is a factor that it must consider at the time it implements the federal plan. This factor, and how the agency proposes to consider it, is discussed in section III.G of this preamble below.

the EPA will administer. ERCs may be bought and sold, or banked for use in later years. The rate-based approach is explained in greater detail in section IV of this preamble.

2. The Mass-Based Approach

The second approach to a federal plan that the EPA is proposing in this action is a mass-based trading program. In a mass-based program, the EPA would create a state emissions budget equal to the total tons of CO_2 allowed to be emitted by the affected EGUs in each state, consistent with the mass goals established in the EGs. The EPA would initially distribute the allowances within each state budget—less three proposed allowance set-asides—to the affected EGUs based on their historical generation. Allowances may then be transferred, bought, and sold on the open market, or banked for future use. The compliance obligation on each of the affected EGUs is to surrender the number of allowances sufficient to cover the EGU's respective emissions at the end of a given compliance period. The EPA is also proposing as a part of the mass-based approach three set-asides of allowances: (1) For a Clean Energy Incentive Program; (2) to support renewable energy (RE) projects; and (3) to allocate allowances based on an updating measurement of affected-EGU generation. The EPA is also proposing that a jurisdiction may choose to replace the federal plan allocation provisions with its own allowance allocation provisions. The mass-based approach is explained in greater detail in section V of this preamble.

3. Other Proposed Actions

The EPA is proposing in this action a finding that it is necessary or appropriate to regulate affected EGUs in certain parts of Indian country via a federal plan. This is discussed in section VI.D of this preamble.

In this action, the EPA is also proposing a number of changes to the framework CAA section 111(d) regulations of 40 CFR part 60, subpart B. These changes generally are intended to provide enhancements to the process for state plan submissions and the timing of EPA actions related to state plans and the federal plan. Specifically, the EPA proposes six changes, to include: (1) Partial approval/disapproval mechanisms similar to CAA section 110(k)(3); (2) a conditional approval mechanism similar to CAA section 110(k)(4); (3) a mechanism for the EPA to make calls for plan revisions similar to the ''SIP-call'' provisions of CAA section 110(k)(5); (4) an error correction mechanism similar to CAA section 110(k)(6); (5) completeness criteria and a process for determining completeness of state plans and submittals similar to CAA section 110(k)(1) and (2); and (6) updates to the deadlines for EPA action. These proposed changes are explained in greater detail in section VII of this preamble. They are not a component of the proposed federal plan, or changes in the EGs. If these changes are finalized, they will be applicable to other CAA section 111(d) rules. The EPA intends to finalize these changes earlier than the finalization of the model trading rules.

C. Who does the Proposed Action apply to?

Regulated Entities. Existing fossil fuel-fired EGUs (or affected EGUs) covered by the final Clean Power Plan that are located in a state that does not have an EPA-approved state plan are potentially subject to this proposed action. Affected EGUs are those that were in operation, or had commenced construction, on or before January 8, 2014.[4] The following North American Industrial Classification System (NAICS) codes apply as shown in Table 1 of this preamble:

TABLE 1—EXAMPLES OF POTENTIALLY REGULATED ENTITIES [a]

Category	NAICS code	Examples of potentially regulated entities
Industry	221112	Fossil fuel electric power generating units.
State/Local Government	[b] 221112	Fossil fuel electric power generating units owned by municipalities.

[a] Includes NAICS categories for source categories that own and operate electric power generating units (includes boilers and stationary combined cycle combustion turbines).

[b] State or local government-owned and operated establishments are classified according to the activity in which they are engaged.

This table is not intended to be exhaustive, but rather provides a general guide for identifying entities likely to be affected by the proposed action. Whether an affected EGU is affected by this action is described in the applicability criteria in 40 CFR 60.5845 and 60.5850 of subpart UUUU. Questions regarding the applicability of this action to a particular entity should be directed to the person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section of this preamble.

1. What is an affected electric utility generating unit?

For the federal plan, the definition of an affected EGU is identical to the definition in the final Clean Power Plan. Additionally, the applicability of the federal plan is consistent with the EGs, where an affected EGU subject to the federal plan is any steam generating unit (SGU), integrated gasification combined cycle (IGCC), or stationary combustion turbine (SCT) that was in operation or had commenced construction as of January 8, 2014,[5] and that meets certain criteria, which differ depending on the type of unit. The criteria to be an affected EGU are as follows: A unit, if it is a SGU or IGCC, must serve a generator capable of selling greater than 25 MW (Megawatts) to a utility power distribution system, have a base load rating greater than 260 GJ/h (250 MMBtu/h) heat input of fossil fuel (either alone or in combination with any other fuel), and historically have supplied more than ⅓ of its potential electric output and 219,000 MWh as net-electric sales on any 3 calendar year basis. If a unit is a SCC, the unit must meet the definition of a combined cycle or combined heat and power (CHP) combustion turbine, serve a generator capable of selling greater than 25 MW to a utility power distribution system, have a base load rating of greater than 260 GJ/h (250 MMBtu/h), and historically have combusted more than 90 percent natural gas on a heat input basis on an annual basis.

[4] An affected EGU is any fossil fuel-fired EGU that was in operation or had commenced construction as of January 8, 2014, and is therefore an ''existing source'' for purposes of CAA section 111, but in all other respects would meet the applicability criteria for coverage under the GHG standards for new fossil fuel-fired EGUs.

[5] January 8, 2014 is the date the proposed GHG standards of performance for new fossil fuel-fired EGUs were published in the **Federal Register** (79 FR 1430).

2. How To Determine if a Unit Is Covered By an Approved and Effective State Plan

Section 111(d) of the CAA, as amended, 42 U.S.C. 7411(d), authorizes the EPA to develop and implement a federal plan for affected EGUs upon the EPA's action finding a failure to submit or disapproving a state plan.[6] The affected EGUs covered in EPA-approved state plans are not subject to the federal plan. If the federal plan has been put in place in a state, but is later replaced by an EPA-approved state plan, the affected EGUs would become subject to the state plan as of the effective date specified in a **Federal Register** notice regarding the EPA's approval of the state plan. The EPA is not expecting state plans to be submitted by the states that submit negative declarations. However, in the event that there are later determined to be affected EGUs located in these states, the final federal plan would be applied to such EGUs through a future action. Part 62 of title 40 of the CFR identifies the status of approval and promulgation of CAA section 111(d) state plans for designated facilities in each state. Recognizing the urgent need for actions to reduce GHG emissions, and in accordance with the Presidential Memorandum,[7] as well as the benefit of providing states with model trading rule options to consider as they prepare their state plans, the EPA is proposing this rulemaking concurrently with the Administrator's signing and promulgation of the final Clean Power Plan EGs. 40 CFR part 62 is updated only once per year. Thus, if 40 CFR part 62 does not indicate that your state has an approved and effective plan after the compliance date has passed requiring state plan submittal, you should contact your state environmental agency's Air Director or your EPA Regional Office (see Table 2 in section II.B of this preamble) to determine if approval occurred since publication of the most recent version of 40 CFR part 62.

D. What should I consider as I prepare my comments?

Do not submit information that you consider to be CBI electronically through *http://www.regulations.gov* or email. Send or deliver information identified as CBI to only the following address: OAQPS Document Control Officer (Room C404–02), U.S. EPA, Research Triangle Park, NC 27711, Attention Docket ID No. EPA–HQ–OAR–2015–0199. Clearly mark the part or all of the information that you claim to be CBI. For CBI on 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 marked as CBI will not be disclosed except in accordance with procedures set forth in 40 CFR part 2.

If you have any questions about CBI or the procedures for claiming CBI, please consult the person identified in the **FOR FURTHER INFORMATION CONTACT** section of this preamble.

Docket. The docket number for the proposed action (40 CFR part 62, subpart MMM) is Docket ID No. EPA–HQ–OAR–2015–0199.

World Wide Web (WWW). In addition to being available in the docket, an electronic copy of the proposed action is available on the Internet through the EPA's 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 the proposed action at *http://www2.epa.gov/cleanpowerplan/regulatory-actions#regulations.* Following publication in the **Federal Register** (FR) the EPA will post the *FR* version of the proposed rule and key technical documents on the same Web site.

II. Background Information

A. What is the regulatory development background for this proposed rule?

On August 3, 2015, the EPA finalized the Clean Power Plan EGs for existing fossil fuel-fired EGUs (40 CFR part 60, subpart UUUU) under authority of section 111 of the CAA (79 FR 34950). The Guidelines apply to existing fossil fuel-fired EGUs, *i.e.,* those that were in operation or had commenced construction before January 8, 2014. States with existing EGUs subject to the EGs are required to submit to the EPA by September 6, 2016, a state plan that implements the EGs. States may also make initial plan submittals in lieu of a complete state plan, in which case extensions will be granted until September 6, 2018 (40 CFR part 60, subpart UUUU).[8] As discussed in section VI.D of this preamble, Indian Tribes may, but are not required to, submit tribal plans. Once the EPA finds that a state has failed to submit a plan, or disapproves a state plan,[9] section 111 of the CAA and 40 CFR 60.27 require the EPA to develop, implement, and enforce a federal plan for existing EGUs located in that state. In addition, CAA section 301(d)(2) authorizes the Administrator to treat an Indian Tribe in the same manner as a state for this EGU requirement. *See* 40 CFR 49.3; *see also* ''Indian Tribes: Air Quality Planning and Management,'' hereafter ''Tribal Authority Rule,'' (63 FR 7254, February 12, 1998). As discussed in section VI.D of this preamble, the agency in this action is proposing a necessary or appropriate finding for the affected EGUs in several areas of Indian country and is proposing the federal plan for these affected EGUs.

The agency believes it is appropriate to propose the federal plan at this time for any states that may ultimately be found to have failed to submit a plan, or had their plan disapproved by the EPA. For some states in this situation, the federal plan may be no more than an interim measure to ensure that congressionally mandated emission standards under authority of section 111 of the CAA are implemented until they can get an approved plan in place. Other states may choose to rely on the federal plan and would not need to develop their own plan. This proposal also serves as two proposed model trading rules which states can adopt or tailor for adoption as their state plan. The role of the model rules is discussed in section II.B of this preamble.

In this proposal, the EPA is soliciting public comment only on the proposed approaches for a federal plan and model trading rule for the implementation of the Clean Power Plan EGs. Comments on the underlying Clean Power Plan rule will be considered outside the scope for this proposed rule.

B. What is the purpose of this proposed rule?

The purpose of this action is two-fold: (1) To co-propose two approaches to a

[6] In this Preamble, the term ''state'' generally encompasses the 50 states and the District of Columbia, U.S. territories, and any Indian Tribe that has been approved by the EPA pursuant to 40 CFR 49.9 as eligible to develop and implement a CAA section 111(d) plan. However, the federal plan is not proposed for affected EGUs in certain states or territories where the EGs did not finalize emission performance rates.

[7] Presidential Memorandum—Power Sector Carbon Pollution Standards, June 25, 2013. *http://www.whitehouse.gov/the-press-office/2013/06/25/presidential-memorandum-power-sector-carbon-pollution-standards.*

[8] See section VII of this preamble for additional information on proposed changes to 40 CFR 60.27 to provide enhancements and flexibilities to the agency's process for review and action on state plans and promulgation of federal plans.

[9] If a state has submitted a complete plan, then the EPA will go through a public notice and comment process to fully or partially approve or disapprove the state plan.

federal plan to implement the Clean Power Plan EGs for affected EGUs operating in any state lacking an approved state plan by the relevant deadlines; and (2) to propose these same approaches as model trading rules for states to consider in developing their own plans.

1. Federal Plan

Section 111 of the CAA and 40 CFR 60.27 require the EPA to develop, implement and enforce a federal plan to cover existing EGUs located in states that do not have an approved plan. Section 111(d) of the CAA relies upon states as the preferred implementers of EGs for existing EGUs. States with affected EGUs are to submit state plans or make initial submittals to the EPA by September 6, 2016 pursuant to the EGs.[10] States without any existing EGUs are directed to submit to the Administrator a letter of negative declaration certifying that there are no affected EGUs in the state. No plan is required for states that do not have any affected EGUs. Affected EGUs located in states that mistakenly submit a letter of negative declaration will become subject to the federal plan until a state plan covering those EGUs becomes approved. The EPA intends to finalize the federal plan only for those states that the EPA finds failed to submit plans or whose plans the EPA disapproves. For more information on the timing and mechanics of EPA action on state plans and finalization of this federal plan, see section II.D of this preamble below.

2. Model Trading Rule

The EPA is also proposing the federal plan approaches as two forms of a model trading rule (mass-based and rate-based), which states can adopt or tailor for implementation as a state plan under the EGs. The EPA intends to finalize the model trading rules earlier than it promulgates a federal plan for a state. When the EPA finalizes one or both of its proposed approaches as a final model trading rule, and a state adopts a final model trading rule in its entirety as its state plan, it would be presumptively approvable.

The EPA has designed these rules so that they meet the requirements of the final EGs. If one of the model rules is adopted by a state without any change, it would be presumptively approvable. We use the term ''presumptively'' in recognition that a state plan submission must be accompanied by other materials in addition to the regulatory provisions. These requirements are set forth in the final Clean Power Plan and framework regulations of 40 CFR part 60, subpart B. For instance, they include a formal letter of submittal from the Governor or his or her designee, evidence that the rule has been adopted into state law and that the state has necessary legal authority to implement and enforce the rule, and evidence that procedural requirements, including public participation under 40 CFR 60.23, have been met.

In further support of state use of the model rules, we are drafting the model trading rule so that it can be adopted or incorporated by reference with a minimum of changes that would be necessary to make the rule appropriate for use by states. This way, a state may incorporate by reference the model rule as the state plan, or as the backstop to a state measures plan with few if any adjustments. States may make changes to the model trading rule, so long as they still meet the requirements of the EGs. If the state chooses to tailor or modify the model trading rule such as by expanding the scope of eligibility of projects that may generate ERCs in a rate-based trading program, the EPA may still approve the plan, but the EPA would conduct appropriate review of such provisions for consistency with the EGs and the state would have to demonstrate to the EPA's satisfaction that its alternative provisions are as stringent as the presumptively approvable approach described. We note here, and in the regulatory text of the model trading rule, that the scope of eligibility of proposed ''ERC resources'' for the federal plan is different than the scope of eligibility provided for in the model rule. Thus, all of the language and provisions in the regulatory text relevant to these other ERC resources is relevant only to the proposed model trading rule and not to the federal plan as such (*i.e.,* those ERC resources discussed in section IV.C.3 of this preamble are applicable to the model rule and only metered RE and applicable nuclear are applicable to the federal plan).

The EPA's approval of a state plan, including a plan that adopts the model trading rule, will be the result of an independent notice-and-comment rulemaking process. Without prejudging the outcome of that process, the EPA recognizes that it may be able to approve or ''conditionally approve'' state plans that are substantially similar, but not identical to, the final model trading rules. Ultimately, state plans must meet the requirements of the EGs for approvability. Thus, a conditional approval would be based on a condition that the state take such actions as may be necessary by a date certain to meet the requirements of the EGs. (The EPA is proposing to explicitly provide for conditional approvals in the CAA section 111(d) framework regulations. See section VII.B of this preamble.)

In accordance with the EGs, the process for review and approval (or disapproval) of state plans, whether based on the model trading rules or otherwise, would occur once the states have made their submissions by September 6, 2016. As provided in the EGs, states have the option of not submitting a full state plan, but rather making an initial submittal, in order to obtain an extension of 2 years before submitting a full state plan for EPA approval. It could be beneficial for coordination purposes if a state that is interested in adopting one of the model trading rules but intends to make an initial submittal next year were to indicate which model trading rule they intend to adopt. This is not an additional requirement beyond what the EGs require for initial submittals, however.

The EPA strongly encourages states to consider adopting one of the model trading rules, which are designed to be referenced by states in their rulemakings. Use of the model trading rules by states would help to ensure consistency between and among the state programs, which is useful for the potential operation of a broad trading program that spans multi-state regions or operates on a national scale. As discussed at length in the EGs, EGUs operate less as individual, isolated entities and more as multiple components of a large interconnected system designed to integrate a range of functions that ensure an uninterrupted supply of affordable and reliable electricity while also, for the past several decades, maintaining compliance with air pollution control programs. Since, as a practical matter under both the EGs and any federal plan, emission reductions must occur at the affected EGUs, a broad-scale emissions trading program would be particularly effective in allowing EGUs to operate in a way that achieves pollution control without disturbing the overall system of which they are a part and the critical functions that this system performs. In addition, consistency of requirements benefits the affected EGUs, as well as the states and the EPA in their roles as administrators and implementers of a trading program. States of course remain free to develop a plan of their own choosing to submit to the EPA for approval following the

[10] States may request extensions of up to two years as part of a complete initial CAA section 111(d) submission.

criteria set out in the final Clean Power Plan EGs.

The EPA believes there are compelling policy reasons that support the provision of a proposed model trading rule at this time. The EPA has heard from multiple stakeholders and in public comments submitted on the proposed EGs that there is a strong interest in seeing a model state plan or trading rule prior to the deadline for state submittals under the EGs. According to these stakeholders, model rules can provide predictability for planning purposes, both among states and affected EGUs. In addition, some states have indicated that they may prefer to rely on a federal plan, either temporarily or permanently, rather than develop a plan of their own. This proposal of a model trading rule addresses these policy interests.

The approach of proposing model trading rules that are identical in all key respects to proposed federal plans that may be promulgated later, is consistent with prior CAA section 111(d) and CAA section 110 rulemakings. For example, the NO_X state implementation plan (SIP) Call model rule at 40 CFR part 96 (63 FR 57356; October 27, 1998) was identical in all meaningful respects with the Federal NO_X Budget Trading Program at 40 CFR part 97 (65 FR 2674; January 18, 2000). And the CAIR model rule in 40 CFR part 96 (70 FR 25339; May 12, 2005) was identical in all meaningful respects with the federal CAIR in 40 CFR part 97 (71 FR 25396; April 28, 2006).[11] While these identical programs for model rules and Federal Implementation Plans (FIPs) were finalized in separate parts of the CFR, the EPA does not see any reason that it could not just as easily propose the federal plan as the model trading rule in the same section of the CFR.[12] If a federal plan were to be finalized for a given state at a later time, this would be reflected in 40 CFR part 62 by cross-reference, along with any modifications or adjustments that may be appropriate at the time of actual promulgation of a federal plan.

TABLE 2—REGIONAL OFFICE CONTACTS

Region	Regional contact	Phone	States and protectorates
Region I	Shutsu Wong, *wong.shutsu@epa.gov*	617–918–1078	Connecticut, Massachusetts, Maine, New Hampshire, Rhode Island, Vermont.
Region II	Gavin Lau, *lau.gavin@epa.gov*	212–637–3708	New York, New Jersey, Puerto Rico, Virgin Islands.
Region III	Mike Gordon, *gordon.mike@epa.gov*	215–814–2039	Virginia, Delaware, District of Columbia, Maryland, Pennsylvania, West Virginia.
Region IV	Ken Mitchell, *mitchell.ken@epa.gov*	404–562–9065	Florida, Georgia, North Carolina, Alabama, Kentucky, Mississippi, South Carolina, Tennessee.
Region V.	Alexis Cain, *cain.alexis@epa.gov*	312–886–7018	Minnesota, Wisconsin, Illinois, Indiana, Michigan, Ohio.
Region VI	Rob Lawrence, *lawrence.rob@epa.gov*	214–665–6580	Arkansas, Louisiana, New Mexico, Oklahoma, Texas.
Region VII	Ward Burns, *burns.ward@epa.gov*	913–551–7960	Iowa, Kansas, Missouri, Nebraska.
Region VIII	Laura Farris, *farris.laura@epa.gov*	303–312–6388	Colorado, Montana, North Dakota, South Dakota, Utah, Wyoming.
Region IX	Ray Saracino, *saracino.ray@epa.gov*	415–972–3361	Arizona, California, Hawaii, Nevada, American Samoa, Guam, Northern Mariana Islands.
Region X	Dan Brown, *brown.dan@epa.gov*	503–326–6823	Alaska, Idaho, Oregon, Washington.

C. Legal Authority

Section 111(d)(2) of the CAA, 42 U.S.C. 7411(d)(2) provides the EPA the same authority to prescribe a plan for a state in cases where the state fails to submit a satisfactory plan as the agency would have under CAA section 110(c) in the case of failure to submit an implementation plan. In addition, the EPA has authority under CAA section 111(d)(1) to prescribe regulations that establish procedures similar to CAA section 110 with respect to the submission of state plans, and the EPA also has general rulemaking authority as necessary to implement the CAA under CAA section 301. A federal plan under CAA section 111(d) applies, implements and enforces standards of performance for affected EGUs. Under the Clean Power Plan EGs, state plans will be due on September 6, 2016, but states are also allowed to seek a 2-year extension for a final plan submittal, upon a satisfactory initial plan submittal by the same deadline. *See* 40 CFR 60.5755, 60.5760(b). If a state does not submit a final state plan or initial plan submittal,[13] or if either a final state plan or an initial plan submittal does not meet the requirements of the EG, the agency will take the appropriate steps to finalize and implement a federal plan for that state's EGUs.

Further, states will remain free, and indeed are strongly encouraged, to submit an approvable state plan even after promulgation of the federal plan for their jurisdictions. The EPA will withdraw the federal plan for a state when that state submits, and the EPA approves, a final plan. *See* 40 CFR 60.5720.

D. Timing of EPA Actions on the Model Trading Rules, Federal Plan, and Other Proposed Actions

This action co-proposes two approaches to the federal plan, both of which also constitute proposed model trading rules that states could adopt as state plans for EPA approval. The EPA currently intends to finalize one or both of the model trading rules by next summer so that they may be available to states as soon as possible to help inform their state plan development efforts prior to the initial submittal deadline of September 6, 2016, and 2 years before the states' final plan deadline of September 6, 2018.[14] If the EPA

[11] We also note that historically under the CAA section 111(d)/129 rules, the content of EGs and their corresponding federal plans have had significant overlap.

[12] We propose to include a note in the regulatory text explaining where aspects of the proposed subpart relevant to states as part of the model trading rule are not applicable.

[13] Indeed, states may simply choose to accept a federal plan in lieu of undertaking to develop a state plan at all. While the statute uses the phrase ''fails to submit a satisfactory plan,'' the EPA does not believe this should carry any pejorative connotation. While Congress identified states and local governments as having ''primary responsibility'' for air pollution prevention and control, CAA section 101(a)(3), states are in no way penalized for not submitting a plan under CAA section 111(d). Rather, the EPA steps into the shoes of the state to carry out the CAA section 111(d) program in its stead. To the extent states may be interested in accepting a federal plan, the EPA would be interested in hearing that through the comment process on this proposal.

[14] We anticipate that the model rules' text could be finalized either in a new subpart or subparts of 40 CFR part 62 of title 40 of the CFR as proposed, or in a final document that is not published in the CFR.

finalizes the model trading rules in that timeframe, the only direct consequence will be to provide the states certainty as to one or two particular approaches to the design of their state plan that the EPA will approve if adopted in full. The finalization of a model trading rule will not constitute a final action with respect to a federal plan for the affected EGUs in any state. Rather, the proposed federal plan will remain just that, a proposal. The EPA will promulgate a final federal plan for any state only after it has made a finding on a state's failure to submit a plan, or fully or partially disapproved a submitted state plan. The EPA will go through a public notice and comment process before disapproving a submitted and complete state plan, in whole or part. The EPA invites comments on this staged approach to finalizing one or more model trading rules on the one hand (which we currently intend to do in summer 2016), and finalizing federal plans on the other (which we currently intend to do state-by-state upon our taking predicate action on states' plans).

In this action, the EPA is also proposing enhancements to the process for agency action on state submittals and promulgation of a federal plan under CAA section 111(d). For more detailed discussion of these changes, see section VII of this preamble. This aspect of this proposal is separate from the federal plan and the model trading rules. The EPA intends to finalize these changes on a timeline earlier than both a model trading rule and the federal plan.

Under the framework regulations as proposed to be amended, *see* section VII below, and the final EGs, at 40 CFR 60.27 and 60.5715 and 5760, respectively, the initial timelines for EPA action on state submittals and, potentially, the promulgation of a federal plan will be as follows: The EPA will have 12 months from the date of a state's submission to approve or disapprove that state's plan. The EPA will have 12 months from the date of its action on a state submission to promulgate the federal plan for the EGUs in that state. Under the completeness-criteria process proposed to be added to 40 CFR 60.27, *see* section VII.E below, the EPA would have 6 months from the deadline for a state's submission to notify a state that its submittal does not meet completeness criteria and constitutes a failure to submit a plan. In the case of initial submittals under 40 CFR 60.5765, the EPA will have 90 days from the date the EPA received the initial submittal to notify a state that its initial submittal does not meet the requirements of 40 CFR 60.5765(a). As with state plans, the EPA will have 12 months to promulgate a federal plan from the date of its finding that a state failed to submit a complete and approvable initial submittal. (Formally, such a finding would be that the state failed to submit a state plan.)

The timeframes stated in the previous paragraph reflect the maximum time allowed for EPA action. We note that under CAA section 111(d)(2) and CAA section 110(c), the EPA may promulgate a final federal plan for a state immediately upon making a finding of failure to submit a state plan or initial submittal, or upon making a finding of final disapproval of a state plan. Congress gave the EPA authority in CAA section 111(d)(2), as it did in CAA section 110(c), to promulgate a federal plan at any time after it disapproves or finds a failure to submit a state plan. The Supreme Court has recognized that under this authority, the EPA may promulgate a FIP ''at any time'' within the 2-year limit of CAA section 110(c) ''that begins the moment EPA determines a SIP to be inadequate.'' *EME Homer City* v. *EPA,* 134 S. Ct. 1584, 1601 (2014). ''EPA is not obliged to wait two years or postpone its action even a single day . . . .'' *Id.* It is essential to implement plans for the control of emissions of CO_2 expeditiously and avoid unnecessary delay. Among other reasons, this will provide affected EGUs regulatory certainty and will assist the regulated entities as well as those authorities with responsibility for ensuring grid reliability to have as much time as possible to plan for the 2022 compliance start date set in the EGs. Thus, it is reasonable to propose this federal plan now so that federal plans will be ready to be promulgated quickly in cases where states have failed to submit a plan or their plans are found unsatisfactory.

It is the agency's intention to promulgate federal plans promptly for states who do not submit plans or initial submittals by September 6, 2016. However, the effect of putting the federal plan in place at that time would ultimately be limited in impact upon states. Because the EPA would implement the federal plan, its promulgation does not obligate state officials to take any actions themselves. Further, states remain free—and the EPA in fact encourages states—to submit state plans that can replace the federal plan. States can do so in advance of the beginning of the performance period in 2022, or may transfer to a state plan after that date. However, in doing so, the agency and states should be mindful of the goals of regulatory certainty discussed in the prior paragraph.

Because we are proposing a federal plan that would apply emission standards to affected EGUs in all states that the agency determines not to have an approvable plan, the EPA invites comment from all persons with concerns about or comments on the proposed federal plan as it may apply in any state, whether or not that state has submitted, or intends to submit, its own plan on which the EPA has yet to take action.

In this document, the EPA is proposing regulatory text setting out the substantive provisions for both of the proposed federal plans/model trading rules. The EPA is not providing specific regulatory text that would, if finalized, actually promulgate a federal plan for each state for which this proposed federal plan might be applied.[15] We currently envision that this language would be in the form of a new section to the state-specific subparts of part 62 and would be ministerial in nature. It would likely provide that the affected EGUs in each such state are subject to a federal plan and would then cross-reference or incorporate by reference the substantive provisions of one of the two subparts proposed in this action (if finalized), along with any applicable modifications or adjustments as may be necessary, either based on new information or in response to comments regarding the application of the federal plan to that particular state. This text may appear similar to the FIP language found in the final CSAPR rule (76 FR 48208, 48361–78; August 8, 2011).

E. Use of the Model Trading Rule as a Backstop

As discussed in the final EGs, the EPA believes that either a mass-based or rate-based model trading rule could function well as the federally enforceable ''backstop'' that the EGs require to be included in ''state measures'' type state plans.[16] (The proposed federal plan does not itself require a ''backstop'' because it relies on an ''emission standards'' approach, rather than a ''state measures'' approach, as delineated in the final EGs.) The conditions and requirements for the federally enforceable backstop in a state measures approach are discussed in

[15] The minimum contents of a notice of proposed rulemaking under the CAA are set forth at CAA section 307(d)(3) and 5 U.S.C. 553(b).

[16] We are aware of at least one case in which a court has upheld the use of a trading program as a backstop to ensure CAA requirements are met. *See WildEarth Guardians* v. *U.S. EPA,* No. 12–9596 (10th Cir. filed October 21, 2014) (upholding use of backstop cap-and-trade program under 40 CFR 41.309 of the Regional Haze Rule).

detail in the final EGs. *See* sections VIII.C.3.b and VIII.C.6.c of the final EGs. To summarize those provisions, without reopening them for comment, the federally enforceable backstop must fully achieve the CO_2 emission performance rates or the state's interim and final CO_2 emission goals if the state plan fails to achieve the intended level of CO_2 emission performance. The state plan submittal must identify the federally enforceable emission standards for affected EGUs that would be used in the backstop, demonstrate that those emission standards meet the requirements that apply in the context of an emission standards approach, identify a schedule and trigger for implementation of the backstop that is consistent with the requirements in the EGs, and identify all necessary state administrative and technical procedures for implementing the backstop (*e.g.,* how and when the state would notify affected EGUs that the backstop has been triggered). In addition, the backstop emission standards must make up for any shortfall in CO_2 emission performance during a prior plan performance period that led to triggering of the backstop.

The EGs explicitly recognized that the backstop emission standards could be based on one of the model trading rules that the EPA is proposing in this action. As discussed in section II.B of this preamble above, we are drafting the model trading rule so that it can be adopted or incorporated by reference with a minimum of changes necessary to make the rule appropriate for use by states, and this includes its use as a backstop. Instances of this approach are throughout the proposed rule text and reflect our desire to ease the use of the model rule for states, as a full state plan, or as a backstop to a ''state measures'' plan.

One way in which a backstop may need to differ from the model trading rules proposed in this action is the requirement to make up for a shortfall in emissions performance in a state's prior plan performance period. The model trading rules do not provide provisions that would automatically adjust the emission standards to account for any prior emission performance shortfall (which is an option states have if designing their own backstop). Thus, a state relying on the model trading rule as its backstop would likely need to submit an appropriate revision to the backstop emission standards adjusting for the shortfall through the state plan revision process. This would likely be done in conjunction with the process for putting the backstop into effect.

If a state chooses to use the model rule as its federally enforceable backstop in a state measures plan, this does not mean that the backstop is itself the federal plan. Rather, the model rule becomes adopted as a part of the state plan. Both approaches to the model trading rule are ''emission standard'' approaches under the EGs where an emission standard is imposed and federally enforceable on the affected EGUs: In the rate-based approach the emissions standard is an allowable rate of emissions; in the mass-based approach the emission standard is the requirement to hold allowances equal to reported emissions. The EPA may also handle the administration of the trading program for states utilizing the model trading rule. However, even though the backstop may take the form of an EPA-administered, federally-enforceable trading rule, this does not mean that a federal plan has been put into effect. The state retains all of its rights and responsibilities with respect to the implementation and enforcement of the backstop as a component of its state plan.

Applicability and Enforceability. If promulgated for the affected EGUs in a particular state, this federal plan will require affected EGUs to meet specific emission standards for CO_2 and related requirements. These enforceable compliance obligations will apply to the owners and operators of those affected EGUs. *See* 40 CFR 62.13. No obligation falls on states or state officials (except to the extent they may be owners and operators of affected EGUs).[17] In the event of noncompliance, the provisions in the federal plan are federally enforceable against an affected EGU, in the same manner as the provisions of an approved state plan under CAA section 111(d), and similar to a FIP or an approved SIP under CAA section 110. *See* CAA section 111(d)(2)(B), 42 U.S.C. 7411(d)(2)(B) (power to enforce state and federal plans), section 113(a)–(h), 42 U.S.C. 7413(a)–(h), and section 304, 42 U.S.C. 7604. This means that the Administrator has the ability to enforce against violations and secure appropriate corrective actions pursuant to CAA sections 113(a)–(h), and states and other third parties maintain the ability to enforce against violations and secure appropriate corrective actions pursuant to CAA section 304.

[17] *See Reno* v. *Condon,* 528 U.S. 141, 151 (2000). State officials responsible for developing state plans, however, should be aware of the procedural enhancements being proposed to the framework regulations of 40 CFR part 60, subpart B, in this rulemaking document. These changes are discussed in section VII of this preamble below. These changes are not a component of the proposed federal plan or the EGs. Although these changes do not alter the deadlines or submission obligations provided in the Clean Power Plan Emission Guidelines, state officials and other interested parties are encouraged to review and comment on these changes.

III. Federal Plan Structure To Achieve Reductions

A. Overview

1. Interactions With State Plans and Scope of Trading

The EPA intends to set up and administer a program to track trading programs—both rate-based and mass-based—that will be available for all states that choose it. The EPA proposes that affected EGUs in any state covered by a federal plan could trade compliance instruments with affected EGUs in any other state covered by a federal plan or a state plan meeting the conditions for linkage to the federal plan. In the proposed mass-based federal plan trading program, this would mean that affected EGUs in a state covered by the federal plan or a state meeting the conditions for linkage to the federal plan could use, as a compliance instrument, an allowance distributed in any other state covered by the federal plan or a state meeting the conditions for linkage to the federal plan. Similarly, in the proposed rate-based federal plan trading program approach, this would mean that affected EGUs in a state covered by the federal plan or a state meeting the conditions for linkage to the federal plan could use, as a compliance instrument, an ERC issued in any other state covered by the federal plan or a state meeting the conditions for linkage to the federal plan. We propose that an affected EGU in a state covered by the mass-based trading federal plan must use allowances for compliance (not ERCs). Similarly, an affected EGU in a state covered by the rate-based trading federal plan must use ERCs for compliance (not allowances).

The agency promulgated provisions for ''ready-for-interstate-trading'' plans in the EGs. The EPA is proposing the federal plans as ready-for-interstate-trading plans. State plans that adopt the model rule are also considered ready-for-interstate-trading. The EPA proposes to allow interstate trading between affected EGUs in states covered by the proposed federal plans and affected EGUs in states covered by state plans (referred to below as ''linking'' states, or ''linkages'') under the following conditions, which are discussed further below the list:

- The state plan must be approved.
- The state plan must implement the same type of trading program as the federal plan trading program in order to

be linked for interstate trading, *i.e.,* mass-based trading programs can link to mass-based trading programs only, and rate-based trading programs can link to rate-based trading programs only.

- The state plan must use the identical compliance instrument as the federal plan (this requirement is detailed below).
- The state plan must be approved as a ready-for-interstate-trading plan.
- The state plan must use an EPA-administered tracking system (we are also requesting comment on expanding this to include a state plan that uses an EPA-designated tracking system that is interoperable with an EPA-administered system, as detailed below).

The EPA proposes that interstate ERC trading could occur both (1) from affected EGUs in states covered by the rate-based trading federal plan to affected EGUs in states with approved rate-based trading state plans meeting the proposed conditions for linkages (including the conditions for being ''ready-for-interstate-trading'' that were finalized in the EG), and (2) from affected EGUs in such state-plan-covered states to affected EGUs in federal-plan-covered states. The EPA also requests comment on expanding the scope of interstate trading to include linking states covered by the rate-based trading federal plan with any state that has an approved rate-based trading state plan meeting the proposed conditions for linkages and that uses an EPA-designated ERC tracking system that is interoperable with an EPA-administered ERC tracking system. The EPA also requests comment on allowing a state that has an approved rate-based trading state plan meeting the proposed conditions for linkages and that uses an EPA-designated ERC tracking system to register with the EPA, and after registration, to link with states covered by the rate-based trading federal plan. There are multiple benefits to a registration requirement, which include ensuring that the tracking systems are functionally interoperable.

For the mass-based federal plan, the EPA proposes that interstate allowance trading could occur in both directions, *i.e.,* from affected EGUs in states covered by the mass-based trading federal plan to affected EGUs in states with approved mass-based trading state plans meeting the proposed conditions for linkages, and from affected EGUs in such state-plan-covered states to sources in federal-plan-covered states.

The EPA proposes that a condition of linkage between a state plan and the federal plan is the use of an identical compliance instrument. In the mass-based federal plan the EPA proposes to issue allowances in short tons; as a result, the EPA is proposing in this rule that linkage for the mass-based federal plan is limited to state plans that issue allowances in short tons. The agency also requests comment on whether to extend linkage to state plans that issue allowances in metric tons and on what provisions would be necessary to implement such linkages. The EPA believes that considerations for linkages to state plans that use metric tons may include tracking system design, and stipulation of which parties convert state plan allowances denominated in metric tons to allowances denominated in short tons and at what stage of compliance operations the conversion occurs. The agency requests comment on these and any other considerations for linkages between the federal plan and state plans that issue allowances in metric tons.[18]

The EPA also requests comment on expanding the scope of interstate trading to include linking states covered by the mass-based trading federal plan with any state that has an approved mass-based trading state plan meeting the proposed conditions for linkages and that uses an EPA-designated allowance tracking system that is interoperable with an EPA-administered allowance tracking system. The EPA also requests comment on allowing a state that has an approved mass-based trading state plan meeting the proposed conditions for linkages and that uses an EPA-designated allowance tracking system to register with the EPA, and after registration, to link with states covered by the mass-based trading federal plan.

In the Clean Power Plan EGs, the EPA promulgated requirements that apply to an emissions budget trading state plan that includes non-affected EGU emission sources, to provide the opportunity for such a state plan to be potentially approvable for linking to other state plans (see Clean Power Plan EGs, section VIII). In this proposed rule, the proposed approach to link from the mass-based trading federal plan to state plans could result in linking of the federal plan to state plans that include non-affected emission sources. The EPA requests comment on this proposed approach.

The EPA believes that a broad trading region provides greater opportunities for cost-effective implementation of reductions compared to trading limited to a smaller region. The proposed approach to interstate trading is intended to strike a reasonable balance between providing the opportunity for a wide interstate trading system while maintaining the integrity of the linked programs. The agency requests comment on the proposed approach to interstate trading linkages in the federal plans.

Whether the EPA ultimately finalizes rate-based or mass-based federal plans, the agency believes that the ERC market and the allowance market would be competitive. The opportunities for interstate trading detailed above would reduce any potential for firms to exercise market power in the ERC market or allowance market. The EPA requests comment on this expectation of a competitive ERC market and a competitive allowance market, and comment on potential program design choices that could address any identified market power concern. The EPA intends to provide information to the market and the public, consistent with other trading programs that the agency administers, as detailed in sections IV and V of this preamble, for the rate-based and mass-based approaches, respectively.

A transparent and well-functioning allowance or ERC market is an important element of a mass-based or rate-based trading program. The EPA has over 20 years of experience implementing emissions trading programs for the power sector and based on that experience, believes the potential or likelihood of market manipulation is fairly low. Nonetheless, the EPA is evaluating the options for providing oversight of the allowance or ERC markets that may be established through the final EGs and federal plans. This could include engaging with other federal and state agencies as appropriate, and potentially with third parties, in conducting market oversight. The agency requests comment on appropriate market monitoring activities, which may include tracking ownership of allowances or ERCs, oversight of the creation and verification of credits, and tracking market activity (*e.g.,* transaction volumes and prices).

2. Addressing Potential Leakage and Interstate Effects

The final EGs specify the concern of leakage, which is defined in section VII.D of the final EGs as the potential of an alternative form of implementation of the BSER (*e.g.,* the rate-based and mass-based state goals) to create a larger incentive for affected EGUs to shift generation to new fossil fuel-fired EGUs relative to what would occur when the implementation of the BSER took the form of standards of performance incorporating the subcategory-specific emission performance rates representing

[18] In this preamble all references to ''tons'' are short tons, unless otherwise noted.

the BSER. The final EGs specified that mass-based plan approaches must address leakage, because the form of the mass goals may ultimately impact the relative incentives to generate and emit at affected EGUs as opposed to shifting generation to new sources, with potential implications for whether the mass goal implements or is consistent with the BSER and overall emissions from the sector. These circumstances are much less likely to be present under a rate-based plan approach, where the form of the goal ensures sufficient incentive to affected existing EGUs to generate and thus avoid leakage, similar to the CO_2 emission performance rates. By requiring mass-based plan components that address leakage, the final EGs ensure that mass goals are equivalent to the CO_2 emission performance rates and are thus an equivalent expression of the BSER. Section VII.D of the final EGs details the requirement for addressing leakage and why it is needed, and section VIII.J of the final EGs specifies options for mass-based state plan components that address leakage. We are proposing, as part of the mass-based approach under the federal plan and model rule, to implement allowance allocation approaches to address leakage, specifically through establishing an output-based allocation set-aside and a set-aside that encourages the installation of RE. These proposed strategies are detailed in section V.D of this preamble.

In the final EGs, the EPA also discussed the concern that CO_2 emission reductions would be eroded in situations where an affected EGU in a rate-based state counts the MWh from measures located in a mass-based state, but the generation from that measure acts solely to serve load in the mass-based state. In that scenario, expected CO_2 emission reduction actions in the rate-based state are foregone as a result of counting MWh that resulted in CO_2 emission reductions in a mass-based state. The proposed rate-based approach, in accordance with the final EGs, restricts ERC issuance for any emission reduction measures located in a mass-based state, except for RE. RE measures located in a state with a mass-based state plan can only be approved for ERC issuance for use by a state under a rate-based federal plan if it can be demonstrated that load-serving entities in the rate-based state have contracted for the delivery of the RE generation that occurs in a mass-based state to meet load in a rate-based state. As part of this federal plan, we are proposing that this can be demonstrated through the provision of a power delivery contract or power purchase agreement in which an entity in the rate-based state contracts for the supply of the MWhs in question and providing documentation that the electricity was treated as comparable to a generation resource used to serve regional load that included the rate-based state. This demonstration must be included as part of the project application for ERC issuance to the EPA or its agent from the RE provider in the mass-based state. Once the project is approved, subsequent applications for issuance of credit to the EPA will need to reference that the MWh submitted are associated with that contractual arrangement with the mass-based RE provider. The EPA requests comment on this approach. It should also be noted that we are proposing that under the proposed mass-based approach, if RE located in a mass-based state receives mass-based set-aside allowances for any generation, that generation is not eligible to be issued ERCs in a rate-based state.

The EPA requests comment on the proposed treatment of leakage and of interstate effects under both the proposed rate-based federal plan approach and the proposed mass-based federal plan approach, and as part of the corresponding proposed model rules.

3. Provisions To Encourage Early Action

The EPA outlined and initiated the CEIP in the final EGs (see section VIII.B.2 of the final EGs). The program is designed to incentivize investment in certain types of RE projects, as well as demand-side energy efficiency (EE) projects implemented in low-income communities. These RE projects must commence construction, and these EE projects must commence implementation after the date of submission of a final plan to the EPA by the state they are located on or benefitting, or after September 6, 2018 for those states on whose behalf the EPA is implementing the federal plan, and will receive incentives for the MWh they generate or the end-use energy demand reductions they achieve during 2020 and/or 2021. The CEIP also provides an additional incentive to drive investment in demand-side EE projects implemented in low-income communities. The EPA proposes to apply the CEIP in all states subject to either a rate-based or mass-based federal plan. The EPA's proposed approaches to implementing the program in the rate-based and mass-based federal plans are detailed in sections IV and V of this preamble, respectively.

B. Inventory of Emissions

Fossil fuel-fired EGUs are by far the largest emitters of GHGs among stationary sources in the United States, primarily in the form of CO_2, and among fossil fuel-fired EGUs, coal-fired units are by far the largest emitters. This section describes the amounts of these emissions and places these amounts in the context of the U.S. Inventory of Greenhouse Gas Emissions and Sinks [19] (the U.S. GHG Inventory).

The EPA implements a separate program under 40 CFR part 98 called the Greenhouse Gas Reporting Program [20] (GHGRP) that requires emitting facilities over threshold amounts of GHGs to report their emissions to the EPA annually. Using data from the GHGRP, this section also places emissions from fossil fuel-fired EGUs in the context of the total emissions reported to the GHGRP from facilities in the other largest-emitting industries.

The EPA prepares the official U.S. GHG Inventory to comply with commitments under the United Nations Framework Convention on Climate Change (UNFCCC). This inventory, which includes recent trends, is organized by industrial sectors. It provides the information in Table 3 of this preamble, which presents total U.S. anthropogenic emissions and sinks [21] of GHGs, including CO_2 emissions, for the years 1990, 2005, and 2013.

[19] ''Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2013'', Report EPA 430–R–15–004, United States Environmental Protection Agency, April 15, 2015. *http://www.epa.gov/climatechange/ghgemissions/usinventoryreport.html.*

[20] U.S. EPA Greenhouse Gas Reporting Program Dataset, *see http://www.epa.gov/ghgreporting/ghgdata/reportingdatasets.html.*

[21] Sinks are a physical unit or process that stores GHGs, such as forests or underground or deep sea reservoirs of CO_2.

TABLE 3—U.S. GHG EMISSIONS AND SINKS BY SECTOR

[Million metric tons carbon dioxide equivalent (MMT CO_2 Eq.)] [22]

Sector	1990	2005	2013
Energy [23]	5,290.5	6,273.6	5,636.6
Industrial Processes and Product Use	342.1	367.4	359.1
Agriculture	448.7	494.5	515.7
Land Use, Land-Use Change and Forestry	13.8	25.5	23.3
Waste	206.0	189.2	138.3
Total Emissions	6,301.1	7,350.2	6,673.0
Land Use, Land-Use Change and Forestry (Sinks)	(775.8)	(911.9)	(881.7)
Net Emissions (Sources and Sinks)	5,525.2	6,438.3	5,791.2

Total fossil energy-related CO_2 emissions (including both stationary and mobile sources) are the largest contributor to total U.S. GHG emissions, representing 77.3 percent of total 2013 GHG emissions.[24] In 2013, fossil fuel combustion by the utility power sector—entities that burn fossil fuel and whose primary business is the generation of electricity—accounted for 38.3 percent of all energy-related CO_2 emissions.[25] Table 4 of this preamble presents total CO_2 emissions from fossil fuel-fired EGUs, for years 1990, 2005, and 2013.

TABLE 4—U.S. GHG EMISSIONS FROM GENERATION OF ELECTRICITY FROM COMBUSTION OF FOSSIL FUELS (MMT CO_2) [26]

GHG emissions	1990	2005	2013
Total CO_2 from fossil fuel-fired EGUs	1,820.8	2,400.9	2,039.8
—from coal	1,547.6	1,983.8	1,575.0
—from natural gas	175.3	318.8	441.9
—from petroleum	97.5	97.9	22.4

In addition to preparing the official U.S. GHG Inventory, which represents comprehensive total U.S. GHG emissions and complies with commitments under the UNFCCC, the EPA collects detailed GHG emissions data from the largest emitting facilities in the United States through its GHGRP. Data collected by the GHGRP from large stationary sources in the industrial sector show that the utility power sector emits far greater CO_2 emissions than any other industrial sector. Table 5 of this preamble presents total GHG emissions in 2013 for the largest emitting industrial sectors as reported to the GHGRP. As shown in Table 4 and Table 5 of this preamble, respectively, CO_2 emissions from fossil fuel-fired EGUs are nearly three times as large as the total reported GHG emissions from the next ten largest emitting industrial sectors in the GHGRP database combined.

TABLE 5—DIRECT GHG EMISSIONS REPORTED TO GHGRP BY LARGEST EMITTING INDUSTRIAL SECTORS (MMT CO_2e) [27]

Industrial sector	2013
Petroleum Refineries	176.7
Onshore Oil & Gas Production	94.8
Municipal Solid Waste Landfills	93.0
Iron & Steel Production	84.2
Cement Production	62.8
Natural Gas Processing Plants	59.0
Petrochemical Production	52.7
Hydrogen Production	41.9
Underground Coal Mines	39.8
Food Processing Facilities	30.8

C. Affected EGUs

For the Clean Power Plan and this federal plan, an affected EGU is any SGU, IGCC, or stationary combustion turbine that was in operation or had commenced construction as of January 8, 2014,[28] and that meets the following criteria, which differ depending on the type of unit. To be an affected EGU, such a unit, if it is SGU or IGCC, must serve a generator capable of selling greater than 25 MW to a utility power distribution system and have a base load rating greater than 260 GJ/h (250 MMBtu/h) heat input of fossil fuel (either alone or in combination with any other fuel). If such a unit is a SCT, the unit must meet the definition of a combined cycle or CHP combustion turbine, serve a generator capable of selling greater than 25 MW to a utility power distribution system, and have a base load rating of greater than 260 GJ/h (250 MMBtu/h).

When considering and understanding applicability, the following definitions may be helpful. Simple cycle

[22] From Table ES–4 of ''Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2013'', Report EPA 430–R–15–004, United States Environmental Protection Agency, April 15, 2015. *http://www.epa.gov/climatechange/ghgemissions/usinventoryreport.html.*

[23] The energy sector includes all greenhouse gases resulting from stationary and mobile energy activities, including fuel combustion and fugitive fuel emissions.

[24] From Table ES–2 ''Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2013'', Report EPA 430–R–15–004, United States Environmental Protection Agency, April 15, 2015. *http://www.epa.gov/climatechange/ghgemissions/usinventoryreport.html.*

[25] From Table 3–1 ''Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2013'', Report EPA 430–R–15–004, United States Environmental Protection Agency, April 15, 2015. *http://www.epa.gov/climatechange/ghgemissions/usinventoryreport.html.*

[26] From Table 3–5 ''Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2013'', Report EPA 430–R–15–004, United States Environmental Protection Agency, April 15 2015. *http://www.epa.gov/climatechange/ghgemissions/usinventoryreport.html.*

[27] U.S. EPA Greenhouse Gas Reporting Program Dataset as of August 18, 2014. *http://ghgdata.epa.gov/ghgp/main.do.*

[28] Under section 111(a) of the CAA, determination of affected sources is based on the date that the EPA proposes action on such sources. January 8, 2014 is the date the proposed GHG standards of performance for new fossil fuel-fired EGUs were published in the **Federal Register** (79 FR 1430).

combustion turbine means any stationary combustion turbine which does not recover heat from the combustion turbine engine exhaust gases for purposes other than enhancing the performance of the stationary combustion turbine itself. Combined cycle combustion turbine means any SCT which recovers heat from the combustion turbine engine exhaust gases to generate steam that is used to create additional electric power output in a steam turbine. CHP combustion turbine means any SCT which recovers heat from the combustion turbine engine exhaust gases to heat water or another medium, generates steam for useful purposes other than exclusively for additional electric generation, or directly uses the heat in the exhaust gases for a useful purpose.

We note that certain affected EGUs are exempt from inclusion in a state plan and this federal plan. Affected EGUs that may be excluded under the EGs are those that (1) Are subject to subpart 40 CFR part 60, subpart TTTT as a result of commencing modification or reconstruction; (2) are SGUs or IGCC that are currently and always have been subject to a federally enforceable permit limiting net-electric sales to one-third or less of its potential electric output or 219,000 MWh or less on an annual basis; (3) are non-fossil units (*i.e.,* units that are capable of combusting 50 percent or more non-fossil fuel) that have historically limited the use of fossil fuels to 10 percent or less of the annual capacity factor or are subject to a federally enforceable permit limiting fossil fuel use to 10 percent or less of the annual capacity factor; (4) are stationary combustion turbines that are not capable of combusting natural gas (*i.e.,* not connected to a natural gas pipeline); (5) are CHP units that are subject to a federally enforceable permit limiting, or have historically limited, annual net electric sales to a utility power distribution system to the product of the design efficiency and the potential electric output or 219,000 MWh (whichever is greater) or less; (6) serve a generator along with other SGU(s), IGCC(s), or stationary combustion turbine(s) where the effective generation capacity (determined based on a prorated output of the base load rating of each SGU, IGCC, or stationary combustion turbine) is 25 MW or less; (7) are a municipal waste combustor unit subject to subpart Eb of 40 CFR part 60; or (8) are a commercial or industrial solid waste incineration unit that is subject to subpart CCCC of 40 CFR part 60.[29]

The EPA also requests comment on an alternative compliance pathway that could be available to units under a mass-based approach. The ways that the approach could be implemented are further outlined in the Alternative Compliance Pathway for Units that Agree to Retire Before a Certain Date Technical Support Document (TSD). Under this approach, two basic requirements would need to be met. The first is that the unit would have to take a commitment that it would retire on a date on or before December 31, 2029. The second is that the unit would have to demonstrate that it will take an enforceable emission limitation that would assure that the overall state emission goal is met. The TSD explores ways that this approach could be implemented, including ways that the enforceable emission limitation could be calculated and implemented. The EPA requests comment on whether this approach should be available for all units or limited to small units (*e.g.* less than 100 MW nameplate capacity). The EPA also requests comment on whether and how such an approach could be included under a rate-based approach.

The applicability of this proposed federal plan follows the same applicability criteria as the final EGs. The rationale for these criteria is provided in section IV.D of the Clean Power Plan. We are not reopening the criteria or rationale here.

In the federal plan Affected EGU TSD, the EPA lists all applicable affected EGUs according to our records from the National Electric Energy Data System (NEEDS), Energy Information Administration (EIA), and comments from the Clean Power Plan. In this TSD, each affected EGU is assigned its proposed applicable standards if a federal plan were to be promulgated for that affected EGU at any time. The EPA requests comments and updates to this list of affected units. Section VI.C of the final EGs describes the data used in setting the standards and how an inventory of affected units has been compiled.

D. Compliance Schedule

In accordance with the schedule set out in the EGs, the federal plan is proposed to be implemented in a phased approach. The first period, corresponding to the Interim Period in the EG, is proposed to run from beginning of calendar year 2022 until end of calendar year 2029 (January 1, 2022 to December 31, 2029). The Final Period would run from beginning of calendar year 2030 (January 1, 2030) indefinitely into the future. The first period is proposed to be comprised of three ''compliance periods,'' set by calendar year. The first compliance period will be from January 1, 2022 to midnight, December 31, 2024 (3 calendar years). The second compliance period will be from January 1, 2025 to midnight, December 31, 2027 (3 calendar years). The third compliance period will be from January 1, 2028 to midnight, December 31, 2029 (2 calendar years).

Under the EGs, midnight, December 31, 2029 marks the end of the Interim Period, and the beginning of the Final Period. The EPA proposes that the compliance periods in the Final Period will each be 2 calendar years. Thus, the first compliance period after 2030 would be from January 1, 2030 to midnight, December 31, 2031. The second compliance period would be from January 1, 2032 to midnight, December 31, 2033. This would repeat accordingly unless changed by the EPA through a revision to the federal plan or other action.[30]

The EPA recognizes that the compliance periods provided for in this rulemaking are longer than those historically and typically specified in CAA rulemakings. As reflected in long-standing CAA precedent, ''[t]he time over which [the compliance standards] extend should be as short term as possible and should generally not exceed one month.'' *See e.g.,* June 13, 1989 Guidance on Limiting Potential to Emit in New Source Permitting and January 25, 1995 Guidance on Enforceability Requirements for Limiting Potential to Emit through SIP and § 112 Rules and General Permits. The EPA determined that the longer compliance periods provided for in this rulemaking are acceptable in the context of this specific rulemaking because of the unique characteristics of this rulemaking, including that CO_2 is long-lived in the atmosphere, and this rulemaking is focused on performance standards related to those long-term impacts.

---

[29] We had proposed in the Clean Power Plan EGs that affected EGUs were those existing source fossil fuel-fired EGUs that met the applicability criteria for coverage under the final GHG standards for new fossil fuel-fired EGUs being promulgated under CAA section 111(b). However, we are finalizing in the EGs that states need not include certain units that would otherwise meet the CAA section 111(b) applicability in this CAA section 111(d) EGs. These include simple cycle turbines, certain non-fossil units, and certain CHP units. The final CAA section 111(b) standards include applicability criteria for simple cycle combustion turbines, for reasons relating to implementation and minimizing emissions from all future combustion turbines.

[30] This schedule would be the same under either a rate- or mass-based approach.

Prior to the beginning of the first compliance period in 2022, the agency intends to establish the infrastructure for operating a federal trading program and to work closely with affected EGUs in the states where the federal plan is promulgated prior to the start of the first compliance period in 2022. We request comment on whether it would be possible to grant, on a case-by-case basis, certain affected EGUs, particularly small entities, additional time to come into compliance, and to request additional input from the public as to the design of such flexibility that would be compatible with the EGs and a federal plan that implements a trading system.

The EPA recognizes that it is important to ensure a degree of liquidity in compliance instruments in either of the proposed trading approaches, while also maintaining the stringency required by the final EGs. A number of aspects of the rate-based and mass-based programs would assist with this, including allocation methods or rules, mechanisms to place allowances or credits into the market relatively early, requirements for public transparency of information related to allowance, or credit issuance, tracking, transfers and holdings. The EPA solicits comment on other approaches to ensure market liquidity while continuing to meet the stringency of the final EGs.

E. Addressing Reliability Concerns

The proposed federal plan has been designed to ensure that, to the greatest extent possible, implementation would not interfere with the power sector's ability to maintain electric reliability.[31] Like the EGs, the federal plan provides a long planning horizon and implementation period. In addition the federal plan allows affected EGUs to obtain tradable allowances and credits to meet obligations which assures that reliability can be maintained without disruption to the electricity system.

There are many features of the electricity system that ensure that electric system reliability will be maintained. For example, in the Energy Policy Act of 2005, Congress added a section to the Federal Power Act to make reliability standards mandatory and enforceable by the Federal Energy Regulatory Commission (FERC) and the North American Electric Reliability Corporation (NERC), the Electric Reliability Organization which FERC designated and oversees. Along with its standards development work, NERC conducts annual reliability assessments via a 10-year forecast and winter and summer forecasts; audits owners, operators and users for preparedness; and educates and trains industry personnel. Numerous other entities such as FERC, U.S. Department of Energy (DOE), state public utility commissions (PUCs), independent system operators and regional transmission organizations (ISOs/RTOs), and other planning authorities also consider the reliability of the electric system. There are also numerous remedies that are routinely employed when there is a specific local or regional reliability issue. These include transmission system upgrades, installation of new generating capacity, calling on demand response, and other demand-side actions.

Additionally, planning authorities and system operators constantly consider, plan for and monitor the reliability of the electricity system with both a long-term and short-term perspective. Over the last century, the electric industry's efforts regarding electric system reliability have become multidimensional, comprehensive and sophisticated. Under this approach, planning authorities plan the system to assure the availability of sufficient generation, transmission, and distribution capacity to meet system needs in a way that minimizes the likelihood of equipment failure.[32] Long-term system planning happens at both the local and regional levels with all segments of the electric system needing to operate together in an efficient and reliable manner. In the short-term, electric system operators operate the system within safe operating margins and work to restore the system quickly if a disruption occurs.[33] Mandatory reliability standards apply to how the bulk electric system is planned and operated. For example, transmission operators and balancing authorities have to develop, maintain and implement a set of plans to mitigate operating emergencies.[34]

The EPA's approach in this proposed federal plan builds on the foundation provided in the EGs' determination of the BSER to ensure that the final federal plan, like the final EGs, does not interfere with the industry's ability to maintain reliability of the nation's electricity supply. First, the federal plan, like the EGs, provides more than 6 years before reductions are required and an 8-year period from 2022 to 2029 to meet interim goals. This allows time for planning and steady, measured implementation.

Second, the federal plan is a market-based trading program which will allow affected EGUs the opportunity to buy and sell emissions credits or allowances as well as bank them. The EPA's proposed federal plan includes two alternative approaches: A mass-based trading program and a rate-based trading program. Trading programs of both types have many positive attributes. Among them is that they help to ensure that imposition of the federal plan will not interfere with the industry's ability to maintain the reliability of the nation's electricity supply. Such a program does not restrict unit-level operational decision-making beyond requiring units to hold a sufficient number of tradable permits (*e.g.,* allowances or ERCs) to cover emissions. It, therefore, inherently allows for unit-level operational flexibility to facilitate the maintenance of reliability and makes the program enormously resilient. If a unit finds it needs to run more than anticipated, the market-based compliance system provides a way for the EGU to meet its generation needs while it maintains compliance with the federal plan.

Third, just as we have required the states to do in developing state plans, the EPA is considering reliability as a part of developing this federal plan. For example, the EPA will consult with planning authorities. The EPA will work with the ISO/RTO Council to convene a face-to-face meeting for planning authorities with the EPA during the comment period to discuss any concerns or other feedback on the federal plan from those entities. This meeting will help to ensure that the EPA is taking into consideration any concerns about the relationship of this rulemaking to the ability of the industry to maintain electric reliability across the country as we finalize the federal plan. It will give the planning authorities an opportunity to hear directly from the EPA how the federal plan is designed and gives the planning authorities an opportunity to voice concerns and ask questions. This will help inform comments that planning authorities may submit to the docket.

In the final Clean Power Plan EGs, the EPA laid out the availability of a reliability safety valve that could be used if an unanticipated catastrophic emergency caused a conflict between

[31] The EPA evaluated certain aspects of electric reliability in the context of modeling projections for the final Clean Power Plan, and that evaluation is described in the "Resource Adequacy and Reliability Analysis TSD" for that rulemaking, a copy of which is also included in the docket for this rulemaking.

[32] Casazza, J. and Delea, F., Understanding Electric Power Systems: An Overview of the Technology, the Marketplace, and Government Regulations, IEEE Press, at 160 (2010).

[33] *Id.*

[34] NERC Reliability Standard EOP–001–2.1b—Emergency Operations Planning, available at *http://www.nerc.net/standardsreports/standardssummary.aspx.*

maintenance of electric reliability and inflexible requirements that a state plan might impose on an affected EGU or EGUs. Under the federal plan, inflexible requirements are not imposed on specific plants. Rather as explained earlier, the very nature of the federal plan, in which affected EGUs can obtain allowances or credits if needed, supports reliability. Therefore, a reliability safety valve for the federal plan is not needed. The EPA invites comments on this aspect of the proposed federal plan.

The EPA, DOE, and FERC have agreed to coordinate efforts to help ensure continued reliable electricity generation and transmission during the implementation of the final EGs and the final federal plan in any state that does not have an approved state plan. The three agencies have developed a coordination strategy that reflects their joint understanding of how they will work together to monitor implementation. The three agencies will work together to monitor implementation, share information and resolve any difficulties that may be encountered.

The EPA is not proposing to include an allowance set-aside, or similar mechanism in a rate-based approach, to address reliability issues in the federal plan; however, we request comment on including such a set-aside in the context of a mass-based approach. The EPA requests comment specifically on creation of an allowance set-aside for the purpose of making allowances available in emergency circumstances in which an affected EGU was compelled to provide reliability critical generation and demonstrated that a supply of allowances needed to offset its emissions was not available.

The set-aside would be in addition to the proposed set-asides that are detailed in section V.D in this preamble. The EPA would set aside allowances in each state under the mass-based federal plan, and if a reliability issue is perceived by the EPA, DOE and FERC coordinated monitoring process discussed above, the EPA would distribute allowances from the set-aside to support affected EGUs during or after an unforeseen, emergency reliability event. If there were unused allowances remaining in the set-aside, then the EPA would distribute them to affected EGUs pro rata based on the allocation approach that is detailed in section V.D of this preamble. The EPA requests comment on all elements of such an approach, including what events would trigger the need for allowances from the reliability set-aside; eligibility criteria to receive the set-aside allowances; the size of the set-aside; and the timing of distribution of allowances from the reliability set-aside. Additionally, the EPA requests comment on how a reliability ''set-aside'' approach could be implemented in the rate-based federal plan.

As detailed later in this preamble, the EPA proposes in the federal plan to implement a CEIP, which was established in the EGs to reward investment in certain clean energy projects that achieve MWh results during 2020 and 2021 (see sections IV and V of this preamble for the proposed approach to implement this incentive program in the rate-based and mass-based federal plans, respectively). Implementation of the CEIP in the federal plans would create ERCs and allowances before 2022, allowing for creation of banks that could be used in the event of an unforeseen, emergency reliability issue. The EPA requests comment on the potential for these banks of ERCs and allowances to support reliable electricity generation and transmission to be utilized in the event of this kind of reliability emergency.

F. Worker Certification

In the EGs, the EPA suggested that to ensure that emission reductions are realized, it is important that construction, operations and other skilled work undertaken pursuant to state plans is performed to specifications, and is effective, safe, and timely. The EPA asks for comments as to whether the federal plan should encourage EGUs to ask for a demonstration that the work undertaken under a federal plan is performed by a proficient workforce. A good way to ensure such a workforce is to require that workers have been certified by: (1) An apprenticeship program that is registered with the U.S. Department of Labor (DOL), Office of Apprenticeship or a state apprenticeship program approved by the DOL; (2) a skill certification aligned with the DOE Better Building Workforce Guidelines and validated by a third party accrediting body recognized by DOE; or (3) other skill certification validated by a third party accrediting body.

G. Remaining Useful Lives and Potential for ''Stranded Assets''

Section 111(d)(2) of the CAA provides, ''In promulgating a standard of performance under a plan prescribed under this paragraph, the Administrator shall take into consideration, among other factors, remaining useful lives of the sources in the category of sources to which such standard applies.'' 42 U.S.C. 7411(d)(2). This language tracks similar language in CAA section 111(d)(1) with respect to state plans. In the final EGs, we explained how the Guidelines permit states in applying a standard of performance in their state plans to consider the remaining useful life of a facility. We determined that it was appropriate to specify that the general variance provisions in 40 CFR 60.24(f) should not apply to the class of affected facilities covered by these Guidelines. We concluded that facility-specific factors and in particular, remaining useful life, do not justify a state making further adjustments to the performance rates or aggregate emission goal that the Guidelines define for affected EGUs in a state and that must be achieved by the state plan.

Because the Guidelines do not allow for states to deviate from state goals based on remaining useful life, the EPA does not believe such goal adjustments are necessary or appropriate in the federal plan either. Nonetheless, this does not obviate the requirement that the EPA itself, in the design of its federal plan, consider, among other factors, the remaining useful lives of the affected facilities. The agency therefore proposes the following analysis of this factor.[35]

Congress added the ''remaining useful lives'' factor to CAA section 111(d)(2) in the 1977 CAA Amendments. Congress did not provide in the statute any direction on how or to what degree ''remaining useful lives'' of facilities subject to a section 111(d) federal plan is to be considered. As discussed in the preamble to the final EGs, Congress' intent in enacting the provision was to allow for older facilties with short remaining useful lives to not be required to install capital-intensive pollution control devices to meet emission standards that would only be used for a short period of time before a plant ceased operation. A House of Representatives report on a predecessor bill to the enacted statute stated, ''Older plants with relatively short remaining useful lives might have chosen to cease operation if the *only* means of emission

[35] We note that the preamble and supporting materials for the EGs discuss a related concern raised by some stakeholders, which is whether the EGs could result in widespread ''stranded assets'' as a direct result of the rule. As explained there, we believe this concern is distinct from the ''remaining useful lives'' factor in CAA section 111(d)(1), and for the same reasons, believe it is distinct from the factor Congress directed the agency to consider in CAA section 111(d)(2). Nonetheless, we undertook analysis in the final EGs of whether and to what extent there may be a ''stranded asset'' concern. See memorandum to Clean Power Plan Docket EPA–HQ–OAR–2013–0602 titled ''Stranded Assets Analysis'' dated July 2015. We believe that analysis demonstrates that this is not likely to be a widespread issue under the federal plan either.

limitation available to meet emission limits were pollution control technology.'' H. Report 94–1175, at 159 (1976) (emphasis added). This language is probative of the fact that Congress viewed ''remaining useful lives'' as a consideration for facilities with relatively little remaining useful life. We are confident the proposed federal plan will not force costly pollution control investments at older plants with short remaining useful lives.

Further, the statute provides that this factor is one ''among other factors'' that the agency is to consider in promulgating a standard of performance. Congress provided no guidance in the statute as to what those other factors could be. The inclusion of unspecified factors that the agency may determine for itself to consider, along with the use of the term ''consider,'' highlights that Congress intended to give the agency a substantial degree of discretion in determining how the ''remaining useful lives'' factor is considered. The statute does not require, and Congress did not intend, that this consideration mandate the agency to prevent all premature retirements of affected EGUs, to impose no emission requirements on older affected EGUs, or to ensure that profitability is maintained at all times for all affected EGUs. Congress knew how to explicitly exempt older plants from CAA requirements at the time of the 1977 Amendments. For example, Congress excluded plants in existence before August 7, 1977 from the preconstruction requirements of the prevention of significant deterioration (PSD)/non-attainment new source review (NSR) program, *see* CAA section 165(a). And in CAA section 169A related to visibility impairment in federal class I areas, Congress excluded from applicability units that began operation before August 7, 1962. 42 U.S.C. 7491(b)(2)(A). In CAA section 111(d) Congress did not set any such specific criteria. Rather it directed the agency to ''consider'' the remaining useful lives of facilities, among other factors.

This view also accords with past agency practice in implementing a similar provision. In the 1977 Amendments, Congress listed ''remaining useful life'' as a factor for consideration in the visibility program under section 169A. 42 U.S.C. 7491. The ''remaining useful life of the source'' is one of several enumerated factors that the state or the EPA is to consider in determining the best available retrofit technology (BART) for a particular source. Consistent with congressional purpose, the EPA has implemented this factor in the regional haze program for many years through the BART guidelines, in appendix Y to 40 CFR part 51. In the context of the visibility program, we have interpreted this provision to mean that the remaining useful life should be considered when calculating the annualized costs of retrofit controls. *See* 40 CFR part 51, appendix Y, section IV.D.4.k. In the agency's view, this approach to ''remaining useful life'' aligns with congressional intent and informs our view of how the ''remaining useful lives'' factor should be considered under this CAA section 111(d) federal plan. The key consideration is whether the time period associated with amortizable costs of compliance will exceed the remaining useful lives of the sources in question.

Consistent with legislative intent and past agency practice, we propose that the federal plan adequately considers ''remaining useful lives'' of affected EGUs by providing for trading and other flexibilities authorized in the EGs. To summarize, these include: Relatively long periods for affected EGUs to come into compliance, the ability to credit early action, the use of emissions trading, the use of multi-year compliance periods, and the ability to link to other federal or state plans to create larger emissions markets. The federal plan is proposed to include a Clean Energy Incentive Program as provided for in the EGs, which will credit early action and ease compliance in the initial years of the program. These tools will create economic incentives that reward over-performance of some affected EGUs, and allow others to simply acquire credits or allowances to comply with their emission standard, thereby avoiding the need for installation of costly pollution controls at sources with a short remaining life.

Thus, the proposed federal plan is designed in such a way that it adequately, and inherently, takes into account the remaining useful lives of affected EGUs. It provides substantial compliance flexibility, including means of avoiding the need to make extensive capital investments in control technologies that could not be recouped during the remaining useful lives of a facility.[36] The design of the federal plan as a form of emission trading provides individual affected EGUs the flexibility to make cost-conscious compliance choices. This flexibility avoids or substantially diminishes any likelihood that compliance will be a physical impossibility or result in unreasonable costs.

By relying on either rate- or mass-based emission trading, the proposed federal plan capitalizes on the inherent flexibility available through market-based techniques. In effect, under a trading program with repeating compliance periods, a facility with a short remaining useful life has a total outlay that is proportionately smaller than a facility with a long remaining useful life, simply because the first facility would need to comply for fewer compliance periods and would need proportionately fewer ERCs or allowances than the second facility. Buying ERCs or allowances as a compliance method could avoid excessive up-front capital expenditures that might be unreasonable for facilities with short remaining useful lives, and therefore addresses the consideration of ''remaining useful lives.'' Buying ERCs or allowances as a compliance method also would reduce the potential for stranded assets.

In addition, the timing of the federal plan limits the immediate costs of compliance, particularly for facilities that have useful lives ending before 2022, but also for facilities that have useful lives ending before 2030. There are no compliance obligations for affected EGUs under this federal plan until 2022, when the first compliance period begins. At that point, the agency is following the glide path provided for in the EGs, which begins with relatively higher emission targets that will slowly strengthen over the interim performance period from 2022–2029 through three multi-year compliance periods. The final, most stringent, compliance obligation does not begin until 2030.

Further, unlike state plans that can be more stringent under CAA section 116, the federal plan is no more stringent than the EGs, and, as explained in the EGs, the Guidelines reflect a reasonable, rather than a maximum possible, implementation level for each building block in order to establish overall goals that are achievable. As discussed in the

[36] Because we believe that this is the case for all facilities through the basic design of the federal plan, we also can confirm, in line with the EGs, that the availability of variances from the emission standards is unnecessary in the federal plan. Under the general framework regulations, facility-specific variances from an otherwise applicable standard of performance have been potentially available under the application process in 40 CFR 60.27(e)(2), which incorporates the factors provided in 40 CFR 60.24(f) for states. Consistent with our view that the federal plan adequately considers remaining useful lives, and for the same reasons, the need for facility-specific variances under the circumstances of 60.24(f) (unreasonable costs of controls, physical impossibility of installation of necessary control equipment, or other factors that make longer compliance times or less stringent standards significantly more reasonable) is not expected to arise, and thus, the agency proposes to make 40 CFR 60.27(e) inapplicable in this federal plan.

EGs, the BSER determined an average level of emissions achievable by groups of EGUs, rather than for an individual EGU. In considering the remaining useful lives of facilities under a federal plan, the EPA believes this approach to setting the emission standards, coupled with the ability to trade, adequately accounts for remaining useful lives of facilities. In essence, it allows the facilities to comply with the federal plan through the purchase or acquisition of ERCs or allowances, and to avoid the need to make costly investments in control technology for plants that have short remaining useful lives.[37] For these reasons, the federal plan adequately considers ''remaining useful lives.'' We invite comment on our consideration of facilities' ''remaining useful lives'' in the federal plan.

H. Implications for Other EPA Programs and Rules

1. Title V Permitting

Under the proposed federal plan, title V permits for sources with affected EGUs will need to include any new applicable requirements that the plan places on the affected EGUs. The EPA, however, is not proposing any permitting requirements independent of those that would be required under title V of the CAA and the regulations implementing title V, 40 CFR parts 70 and 71.[38] All major stationary sources of air pollution and certain other sources are required to apply for title V operating permits that include emission limitations and other conditions as necessary to assure compliance with applicable requirements of the CAA, including the requirements of an applicable CAA section 111(d) state plan or federal plan. CAA sections 502(a) and 504(a), 42 U.S.C. 7661a(a) and 7661c(a). The ''applicable requirements'' that must be addressed in title V permits are defined in the title V regulations, and include requirements under CAA section 111(d) (40 CFR 70.2 and 71.2 (definition of ''applicable requirement'')).

The EPA anticipates that, given the nature of the units covered by the proposed federal plan, most of the sources at which they are located are already or will be subject to title V permitting requirements. For sources subject to title V, the requirements applicable to them under the proposed federal plan will be ''applicable requirements'' under title V and, therefore, will need to be addressed in the title V permits. For example, requirements under the proposed federal plan concerning designated representatives, monitoring, reporting, and recordkeeping, the requirement to either meet an emission rate (including through holding ERCs (rate-based approach)), or to hold allowances covering emissions (mass-based approach) will be ''applicable requirements'' to be addressed in the permits.

The EPA does not believe this approach is affected by the Supreme Court's decision in *Utility Air Regulatory Group* v. *U.S. EPA,* 134 S. Ct. 2427 (June 23, 2014). The Supreme Court held that the EPA may not treat GHGs as an air pollutant for purposes of determining whether a source is a major source required to obtain a title V operating permit. In accordance with that decision, the D.C. Circuit's amended judgment on April 10, 2015 vacated the title V regulations under review in that case (40 CFR 70.12 and 71.13) to the extent that they require a stationary source to obtain a title V permit solely because the source emits or has the potential to emit GHGs above the applicable major source thresholds. The D.C. Circuit also directed the EPA to consider whether any further revisions to its regulations are appropriate in light of *UARG* v. *EPA,* and, if so, to undertake to make such revisions. As the agency made clear in a memorandum to Regional Administrators last year, ''While the EPA will no longer apply or enforce the requirement that a source obtain a title V permit solely because it emits or has the potential to emit GHGs above major source thresholds, the agency does not read the Supreme Court decision to affect other grounds on which a title V permit may be required or the applicable requirements that must be addressed in title V permits.'' [39] Accordingly, while the emission of GHGs alone cannot trigger the need for a title V permit under *UARG,* the EPA believes a final federal plan under CAA section 111(d) will create new ''applicable requirements'' in the form of an emission standard (either an emission rate or an allowance system) and related requirements for GHGs (here, CO_2) on affected EGUs. *See* 40 CFR 70.2, 71.2 (definition of ''applicable requirement'' includes ''any standard or other requirement under section 111 of the Act, *including section 111(d)''*) (emphasis added). Thus, an affected EGU may be required to modify its existing title V permit, or obtain a new permit if it does not already have one, if it becomes subject to an emission standard for CO_2 under a CAA section 111(d) federal plan.

The title V permits program is structured to provide flexibility for market-based approaches, such as allowance trading programs under the federal plan, including flexibility to make changes under such programs without necessarily requiring a formal permit revision. For example, the title V regulations provide that a permit issued under title V shall include, for any ''approved * * * emissions trading or other similar programs or processes'' applicable to the source, a provision stating that no permit revision is required ''for changes that are provided for in the permit.'' 40 CFR 70.6(a)(8) and 71.6(a)(8). Consistent with this provision in the title V regulations, the proposed federal plan regulations include a provision stating that no permit revision shall be required for the allocation, holding, deduction, or transfer of allowances once the requirements applicable to such allocations, holdings, deductions, or transfers of CO_2 allowances are already incorporated in such permit. Consistent with title V regulations, this provision should be included in each title V permit for a covered source. As a result, allowances will be able to be traded (or allocated, held, or deducted) under the federal plan without a revision of the title V permit of any of the sources involved.

As a further example of flexibility under title V, and consistent with 40 CFR 70.7(e)(2)(i)(B) and 40 CFR 71.7(e)(1)(i)(B), the EPA is proposing that any changes that may be required to an operating permit with respect to a trading program under the federal plan may be made using the minor permit modification procedures of the title V rules. The EPA proposes that such changes may include the initial changes needed to the title V permit to establish the applicability of the trading program to the source, specify the covered units, and to include other permit terms that may be needed for implementation, including the general approach for monitoring and reporting. The minor permit modification procedures could also be used for any subsequent changes

[37] In addition, the ability to generate ERCs for sale or to sell unneeded emission allowances (depending on whether in a rate- or mass-based system) may give some affected EGUs an economic incentive to take measures to reduce emissions that otherwise would have been uneconomical.

[38] Part 70 addresses requirements for title V programs implemented by state, local, and tribal governments, and part 71 governs the title V program implemented by the EPA or delegate agencies in areas under federal jurisdiction, such as Indian country.

[39] Memorandum from Janet McCabe, Acting Assistant Administrator, Office of Air and Radiation, and Cynthia Giles, Assistant Administrator, to Regional Administrators, Regions 1–10, at 5 (July 24, 2014).

to permit terms that may be needed with respect to the trading program, although we expect such changes to be infrequent. As noted above, once a trading program has been established in the permit, there may be transactions, such as individual trades, that will require no formal permit modification procedures because such trading would be already addressed and allowed by the permit (''provided for in the permit'') provided the changes do not conflict with any existing terms of the permit. If a source wishes to make a change that would go against any express term of the permit, the permit must be revised to allow such a change before the source begins operation of the change. Under the implementation strategy described above, the EPA believes it would be unlikely that any change in trading allowances would violate a term of a permit, but this principle is important to keep in mind when deciding if a minor permit modification is appropriate with respect to operating a trading program in the context of a title V permit.

The EPA believes that the approach to permitting requirements we are proposing here, which imposes no additional permitting requirements independent of title V and provides for the use of minor permit modification procedures, will streamline the process for sources already required to be permitted under title V and for permitting authorities. If there are any sources that would become newly subject to title V as a result of the requirements of this proposed federal plan, the initial title V permit that would be issued pursuant to 40 CFR 70.7(a) or 71.7(a) would address the federal plan requirements, when finalized.

The EPA notes that the approach to title V permitting that is being proposed is somewhat similar to the approach adopted in the final CSAPR. *See* 76 FR 48299–48300 (August 8, 2011). The agency recently issued guidance to assist permitting authorities and sources subject to CSAPR in incorporating CSAPR requirements into title V permits.[40] The EPA invites comment on its proposed approach to permitting requirements for the federal plan, including whether it would be of use to develop guidance similar to the guidance developed for permitting under CSAPR. The EPA invites comment on its proposed approach to incorporating applicable requirements of the federal plan into title V permits and revising those requirements, including specifically seeking comment on whether all requirements should be eligible for incorporation into title V permits via minor modification procedures or if only a specified subset of such requirements should be eligible for such procedures.

The EPA also notes that the applicable requirements of this proposed federal plan would apply to a source and are independently enforceable regardless of whether they have yet been included in the source's Title V permit.

2. Implications for New Source Review Program

The NSR program is a preconstruction permitting program that requires major stationary sources of air pollution to obtain permits prior to beginning construction. The requirements of the NSR program apply both to new construction and to modifications of existing major sources. Generally, a source triggers these permitting requirements as a result of a modification when it undertakes a physical or operational change that results in a significant emission increase and a net emissions increase. NSR regulations define what constitutes a significant net emissions increase, and the concept is pollutant-specific.

In the final EGs, the EPA recognized that, as part of its CAA section 111(d) plan, a state may impose requirements that require an affected EGU to undertake a physical or operational change to improve the unit's efficiency that results in an increase in the unit's dispatch and an increase in the unit's annual emissions. If the emissions increase associated with the unit's changes exceeds the thresholds in the NSR regulations for one or more regulated NSR pollutants, including the netting analysis, the changes would trigger NSR. We noted that while there may be instances in which an NSR permit would be required, we expect those situations to be few.

The EPA believes the analysis of NSR applicability is basically the same for sources under a CAA section 111(d) federal plan. That is, it is conceivable that a source under a federal plan may choose, as a means of compliance with either a rate-based or mass-based approach, to undertake a physical or operational change to improve an affected EGU's efficiency that results in a significant net emissions increase of a regulated NSR pollutant. This would trigger NSR. However, as with state plans, the EPA believes that these situations will be few.

After the proposal for the Clean Power Plan was published in June of 2014, the U.S. Supreme Court issued its opinion in *UARG* v. *EPA,* 134 S. Ct. 2427 (June 23, 2014). The Supreme Court held that an increase in GHG emissions alone cannot by law trigger the NSR requirements of the PSD program under section 165 of the CAA. On remand from the Court, the DC Circuit issued an amended judgment in *Coalition for Responsible Regulation, Inc.* v. *Environmental Protection Agency,* Nos. 09–1322, 10–073, 10–1092 and 10–1167 (D.C. Cir., April 10, 2015), vacating the relevant regulations. Therefore, increases in emissions of GHGs alone, including those that may occur through actions taken at sources to comply with the proposed federal plan (such as may occur when an NGCC unit increases its operations due to generation shift from a SGU), cannot trigger NSR.

The EPA will invite comment on potential scenarios in which affected EGUs, particularly small entities, could be subject to the requirements of the NSR program as a result of taking compliance measures under the federal plan, and any ideas for harmonizing or streamlining the permitting process for such sources that are consistent with judicial precedent. However, the EPA is not proposing any changes to the NSR program in this action, and the agency is not reopening or reconsidering any prior actions or determinations related to NSR in this action. Any comments related solely to the NSR program will be considered outside the scope of this proposed rule.

3. Interactions With Other EPA Rules

Existing fossil fuel-fired EGUs, such as those covered in this proposal, are or will be potentially impacted by several other rules recently finalized or proposed by the EPA.[41] These rules include the Mercury and Air Toxics Standards (MATS) (77 FR 9304; February 16, 2012);[42] the CSAPR; Requirements for Cooling Water Intake Structures at Power Plants (79 FR 48300; August 15, 2014); Disposal of Coal Combustion Residuals from Electric Utilities, promulgated on April 17, 2015 (80 FR 21302); and the

[40] Memorandum from Anna Marie Wood, Director, Air Quality Policy Division, Office of Air Quality Planning and Standards (OAQPS), and Reid P. Harvey, Director, Clean Air Markets Division, Office of Atmospheric Programs (OAP), to Regional Air Division Directors, 1–7, regarding Title V Permit Guidance and Template for the Cross-State Air Pollution Rule (May 13, 2015).

[41] We discuss other rulemakings solely for background purposes. The effort to coordinate rulemakings is not a defense to a violation of the CAA. Sources cannot defer compliance with existing requirements because of other upcoming regulations.

[42] The Supreme Court recently reversed and remanded a DC Circuit Court of Appeals decision that had upheld the MATS rule. *Mich.* v. *EPA,* No. 14–46 (S. Ct. filed June 29, 2015). The Court did not vacate the rule, however, and it remains in effect.

proposed Steam Electric Effluent Limitation Guidelines and Standards (78 FR 34432; June 7, 2013). These rules are discussed in more detail in the final EGs along with steps the EPA is taking to enable compliance with obligations under other power sector rules as efficiently as possible. We solicit comment on whether there are specific things the EPA can do in the design and implementation of the federal plan that further this objective.

I. Administrative Appeals Process

Under either a rate-based or mass-based trading program, the EPA anticipates that there may be situations in which individual parties are affected by decisions of the agency. For example, under a rate-based plan, a determination may be made that an eligibility application by an ERC provider is denied. And, for set-asides in the mass-based program, an affected EGU may believe that its allowance allocation amount was miscalculated. Similar to prior trading programs, the agency believes it would be efficient and potentially avoid the need for recourse to litigation to provide an administrative appeals process. Therefore we are proposing, and requesting comment on, the use of the regulations for appeals procedures set forth in 40 CFR part 78, to provide for the adjudication of certain disputes that may arise during the course of implementation of a federal plan under CAA section 111(d). We also propose to revise part 78 to accommodate such appeals. The part 78 procedures cover prior CAA emission trading programs and were specifically designed with these types of disputes in mind.

The persons eligible to file such appeals would be designated representatives as defined in this proposed rule and other ''interested persons'' as defined in part 78. The filing of an appeal and the exhaustion of administrative remedies under part 78 would be a prerequisite to seeking judicial review. For purposes of judicial review, final agency action would occur only when an agency decision under the federal plan listed as appealable under part 78 has been issued, and the procedures of part 78 for appealing the decision are exhausted.

The actions we propose to list as appealable under the part 78 procedures are as follows:

In the case of the rate-based federal plan: Decisions on an eligibility application for ERCs; decisions regarding the number of ERCs generated; decisions on the transfer of ERCs; decisions on the disallowance of ERCs for compliance; decisions that there has been an excess of emissions requiring a 2-for-1 ERC administrative compliance penalty; decisions regarding deduction or surrender of ERCs for compliance from affected EGUs' compliance accounts; decisions on the accreditation of independent verifiers; the use of error corrections regarding information submitted by ERC providers, affected EGUs, or other ERC account holders; and the finalization of compliance period emissions data, including retroactive adjustment based on audit or other investigation.

In the case of a mass-based federal plan: Decisions on an eligibilty application for set-aside allowances; decisions regarding the allocation of allowances to affected EGUs; decisions regarding the allocation of allowances from set-asides; decisions on the transfer of allowances; decisions regarding the finalization of emissions data by affected EGUs during compliance periods; decisions making error corrections to information submitted by affected EGUs and other account holders; decisions that there has been excess emissions requiring a 2-for-1 allowance administrative compliance penalty; and decisions regarding the deduction or surrender of allowances for compliance from affected EGUs' compliance accounts.

We request comment on this list of actions for both types of approaches to the federal plan, and whether there are other decisions that may be made in the course of implementation of the federal plan that are party-specific that would be appropriate to list as appealable under part 78. We also request comment on whether it would be appropriate for the EPA to finalize an administrative appeals process that differs in any way from that offered under part 78, or in addition to that offered under part 78. If so, we request comment broadly on all aspects of the alternative or additional adminsitrative appeals process, including with respect to any structural, procedural, subtantive, and timing requirements it should include, who should have access to it and in what manner, and how it would differ from part 78. Finally, we request comment on whether, similar to other programs identified in 40 CFR 78.1(a)(1), the agency should make the procedures of part 78 available to any actions of the Administrator under the comparable state regulations approved as a part of a state plan under the EGs.

J. Consistency of Program Structure With Clean Air Act Authority

The EPA is co-proposing two distinct forms of emissions trading as the mechanism for federal implementation of standards of performance that achieve the emission performance levels determined by application of the BSER in the Clean Power Plan EGs. Both proposals are ''emission standard'' approaches as defined in the EGs, and the EPA is not proposing an approach like the ''state measures'' approach that is also available to states in the final EGs. The EPA has legal authority to establish either of the proposed trading systems as a federal plan under CAA section 111(d)(2). We discuss this topic briefly here and invite public comment. The EGs discussed the role of emissions trading in the BSER, *see, e.g.,* section V.A of the preamble to the final EGs. The EPA regards this to be a separate issue and is not revisiting or reopening the discussion of the BSER or the role of trading in the BSER here. The EGs recognize and provide ample opportunity for states to establish standards of performance that allow the use of emissions trading or other multi-unit compliance approaches. Here we discuss why an emissions trading program is a lawful and appropriate form of federal ''implementation'' of a ''standard of performance'' under CAA section 111(d)(2). We invite comment on this legal discussion and the agency's interpretation of its authority.

1. General Section 111(d)(2) Authority

Section 111(d)(2) provides that ''[t]he Administrator shall have the same authority [ ] to prescribe a plan for a State in cases where the State fails to submit a satisfactory plan as he would have under section 7410(c) of this title in the case of failure to submit an implementation plan . . .'' 42 U.S.C. 7411(d)(2)(A).[43]

The phrase ''same authority to prescribe'' indicates that Congress viewed the EPA's authority to issue a federal plan for designated pollutants under CAA section 111(d) as, in some sense, co-extensive with its authority to issue a FIP for National Ambient Air Quality Standards (NAAQS) pollutants under CAA section 110. This authority under CAA section 111, of course, must be understood in reference to the purpose of that section (*i.e.,* to achieve emission reductions for designated pollutants from designated facilities), rather than in reference to the purpose of CAA section 110 (*i.e.,* to attain and

[43] Section 111(d)(2) further provides that ''[i]n promulgating a standard of performance under a plan prescribed under this paragraph, the Administrator shall take into consideration, among other factors, the remaining useful lives of the sources in the category of sources to which such standard applies.'' The agency's interpretation of the ''remaining useful lives'' provision is discussed above in section III.G of this preamble.

maintain the NAAQS). However, it has been the agency's longstanding view that, in both procedural and substantive respects, Congress intended that the CAA section 110 authority be looked to under CAA section 111(d)(2). *See* 40 FR 53340, at 53342 (November 17, 1975) (''It is obvious that [the Administrator] could only prescribe standards on some substantive basis. The references to section 110 of the CAA suggest that (as in CAA section 110) [she] was intended to do generally what the states in such cases should have done, which in turn suggests that (as in CAA section 110) Congress intended the states to prescribe standards on some substantive basis. Thus, it seems clear that some substantive criterion was intended to govern not only the Administrator's promulgation of standards but also [her] review of state plans.'').

Over the several decades of implementation of the CAA, the courts, and the EPA, have addressed the nature and scope of CAA section 110 authority. *See, e.g.,* 71 FR 25328, 25338 (May 12, 2005) (CAIR final rule). In general, the EPA has broad power under CAA section 110(c) to cure a defective SIP. Thus, in promulgating a FIP under CAA section 110, the EPA may exercise its own, independent regulatory authority in accordance with CAA section 110(c) and the CAA more broadly. When the EPA has promulgated a FIP, courts have not required explicit authority for specific measures: ''We are inclined to construe Congress' broad grant of power to the EPA as including all enforcement devices reasonably necessary to the achievement and maintenance of the goals established by the legislation.'' *South Terminal Corp.* v. *EPA,* 504 F.2d 646, 669 (1st Cir. 1974). Further, the same authority that is exercised by the states under the CAA in connection with the adoption, implementation, and enforcement of a SIP may be assumed to be available to the EPA when the agency issues a FIP, after determining that a state has not adopted a satisfactory SIP. As the Ninth Circuit has held, when the EPA acts in place of the state pursuant to a FIP under CAA section 110(c), the EPA ''stands in the shoes of the defaulting state, and all of the rights and duties that would otherwise fall to the state accrue instead to EPA.'' *Central Ariz. Water Conservation Dist.* v. *EPA,* 990 F.2d 1531, 1541 (9th Cir. 1993). *Accord, South Terminal,* 504 F.2d at 668 (''[T]he Administrator must promulgate promptly regulations setting forth an implementation plan for a state should the state itself fail to propose a satisfactory one. The statutory scheme would be unworkable were it read as giving to the EPA when promulgating an implementation plan for a state, less than those necessary measures allowed by Congress to a state to accomplish federal clean air goals. We do not adopt any such crippling interpretation.'').

By the same token, if there are clear limits to the EPA's CAA section 110(c) authority, those too, would arguably carry over to CAA section 111(d)(2). For instance, CAA section 110(c)(1) ties the EPA's authority to promulgate a final FIP for a state to the EPA's predicate action on a SIP (or lack thereof): Generally, either an action disapproving a plan, or a finding that a state has failed to submit a plan. However, even here, as the Supreme Court has recognized, ''the plain text of the CAA grants EPA plenary authority to issue a FIP 'at *any* time' within the 2-year period that begins the moment EPA determines a SIP to be inadequate.'' *EPA* v. *EME Homer City Generation,* 134 S. Ct. 1584, 1602 n.14 (2014).

Congress gave the EPA the same authority to prescribe a plan under CAA section 111(d)(2) as it possesses under CAA section 110(c). The EPA believes this authority is the ''same'' in the sense described above and in the case law.[44] The scope of the EPA's action to undertake a FIP under CAA section 110 is informed by the scope of the state's action to undertake a SIP; likewise, the scope of the EPA's action to undertake a federal plan under CAA section 111(d) is informed by the scope of the state's action to undertake a state plan.

The agency received comments on the proposed EGs from commenters who stated that the EPA cannot require states to implement the building blocks that make up the BSER; for example, ordering re-dispatch to natural gas-fired units, or ordering the construction of RE projects. These commenters went on to say that the EPA itself would have no authority to order these types of actions under a federal plan. As we explained in the Legal Memorandum for the final EGs, and reiterate here, the premise of these comments is incorrect. The EPA is not requiring the implementation of the BSER or the building blocks in the EGs. Even where the EPA is directly implementing standards of performance in a federal plan, the agency will not, and need not, attempt to order sources to implement the measures that comprise the BSER. Rather, as set forth in the co-proposed federal plans discussed in sections IV and V of this preamble, the EPA would set emission standards for each of the affected EGUs in the federal plan state, provide mechanisms for their implementation and enforcement, and otherwise leave to the owners and operators of the affected EGUs the decisions about what measures they want to take to comply with the emission standard. Though the emission standards will be federally enforceable, as under a state plan, sources may achieve them through implementation of measures in the BSER, or any other method.

Thus, the question whether the EPA would have the authority to directly order the implementation of the measures in the building blocks in this proposed federal plan is not only not relevant but represents a categorical misunderstanding of the nature of the BSER in relation to the imposition of standards of performance under a CAA section 111(d) plan. To illustrate this, by the same token the EPA could not enforce many logistical aspects of a control requirement such as a scrubber—for instance, the EPA does not need to assert the authority to order into existence companies that manufacture scrubbers, or order their construction or delivery on a certain schedule. The EPA need not in setting emission standards have before it all of the information regarding manufacturing, transportation of parts, or other logistical requirements to ensure that each scrubber gets constructed and delivered to a source. Similarly, the EPA here does not, and need not, propose an implementation approach of directly intervening to re-dispatch certain units, construct new RE projects, or take other measures, either included in the BSER or not. The agency determined the BSER and emission performance levels in the EGs on a reasonable assumption that all of those things can actually happen. In providing for the implementation of federally enforceable standards of performance in the federal plan proposed in this action, the agency is ensuring that these things will happen.

2. Use of Market Techniques To Implement Standards of Performance Under the Clean Air Act

The use of market techniques such as emission trading is well-supported in the CAA and has many regulatory precedents. The EPA discussed this history, and the reason why trading is a supportable method of

[44] We interpret the cross-reference to be to the currently enacted version of CAA section 110(c), rather than to a prior version. As discussed in section VII of this preamble, below, the current version of CAA section 110, including subsection (c), reflects changes made in the 1990 Amendments based on experience gained in the first two decades of the CAA's implementation. The statute and legislative history do not expressly address the question, but there is no indication Congress would have intended to prevent these improvements from being available under CAA section 111 as well.

implementation of standards of performance under CAA section 111(d) in the EGs. See section V.A of the final EGs. Here we supplement that discussion with respect to the agency's own authority under CAA section 111(d)(2) to use trading as a method of implementation of a ''standard of performance'' in the federal plan.

The 1990 CAA Amendments added broad authorizations for the use of market techniques in several sections of the statute, including Title I. States were provided express authority to use such approaches in their NAAQS implementation plans under CAA section 110(a)(2)(A): ''Each [state] plan shall include enforceable emission limitations and other control measures, means, or techniques (including economic incentives such as fees, marketable permits, and auctions of emissions rights) . . . .'' 42 U.S.C. 7410(a)(2)(A). The EPA was given similar authority in the definition of a ''Federal Implementation Plan'' in CAA section 302, which defines that term as an EPA-promulgated plan, which ''includes enforceable emissions limitations or other control measures, means or techniques (including economic incentives, such as marketable permits or auctions of emissions allowances), and provides for attainment of the relevant national ambient air quality standard.'' 42 U.S.C. 7602(y). Section 111(d)(2) of the CAA provides the EPA the same authority to prescribe a federal plan under CAA section 111 as it would have to promulgate a FIP under CAA section 110(c). Thus, the EPA believes the plain language of the statute authorizes the use of market techniques in CAA section 111(d) federal plans.

However, even if one were to view this language as not wholly unambiguous with respect to the scope of federal authority under CAA section 111, the EPA believes that CAA section 111, in conjunction with authorizations and endorsements of market techniques throughout the CAA, and other indicia of congressional intent, strongly support the view that market techniques are within the EPA's authority to promulgate a federal plan under CAA section 111(d).

Case law throughout the history of the CAA has generally confirmed the legal viability of emissions trading as an implementation measure so long as the trading ultimately achieves the emission reduction goals of the statute. *See, e.g., Sierra Club* v. *EPA,* No. 12–3169 (6th Cir. Filed March 18, 2015), Slip Op. at 11–14 (upholding EPA approval of redesignation of area to attainment on basis that reductions in emissions from cap-and-trade programs (NO_X SIP Call, CAIR, and CSAPR) are permanent and enforceable). *Chevron, U.S.A., Inc.* v. *Natural Res. Def. Council, Inc.,* 467 U.S. 837 (1984) (''*Chevron''*), the seminal case establishing the Supreme Court's standard of review of agency interpretations of the statutes they administer, upheld one of the EPA's early emissions trading programs, the Netting Rules of 1980 (45 FR 52676; August 7, 1980), which the EPA in its discretion chose to allow states to apply in both attainment and nonattainment areas (46 FR 50766; October 14, 1981). The Netting Rules allowed existing major sources to modify without triggering certain requirements of PSD or nonattainment NSR, so long as any increase in emissions associated with the modification is compensated for by a corresponding decrease in emissions elsewhere within the same facility, such that there is no significant net increase in emissions from the facility as a whole. In upholding this approach in *Chevron,* the Supreme Court gave deference to the EPA's definition of the term ''source,'' finding in that term sufficient ambiguity to support the agency's reasoned application of an emissions averaging approach for total pollution emitted from the source. *See EPA* v. *EME Homer City,* 134 S. Ct. 1584, 1603 (2014) (''Because 'a full understanding of the force of the statutory policy . . . depend[s] upon more than ordinary knowledge' of the situation, the administering agency's construction is to be accorded 'controlling weight unless . . . arbitrary, capricious, or manifestly contrary to the statute.' '') (quoting *Chevron,* 467 U.S. at 844).[45]

With the increasing recognition of the utility of trading, crediting, and averaging to meet emission reduction goals efficiently, the EPA set forth a comprehensive policy on trading in 1986. Emissions Trading Policy Statement; General Principles for Creation, Banking and Use of Emission Reduction Credits, 51 FR 43814 (December 4, 1986) (hereinafter ''ERC Policy''). In the ERC Policy, the EPA stated that it ''endorses emissions trading and encourages its sound use by states and industry to help meet the goals of the CAA more quickly and inexpensively.'' At the same time, based on lessons learned from its earlier 1982 trading policy, the EPA took steps to tighten its policies on the use of ''bubbles'' to ensure environmental integrity of trading, particularly in nonattainment areas. The agency emphasized the requirements of enforceability, tracking (and preventing double-counting), determining the appropriate baseline from which to measure emissions, and demonstration of actual air quality benefits.

The use of an emissions trading system for CO_2 reductions for affected EGUs under CAA section 111(d) is also analogous to the trading system for chlorofluorocarbons (CFCs) under the pre-1990 CAA provision for control of stratospheric ozone depleting substances. This program was reviewed by the Office of Legal Counsel (OLC) within the Department of Justice in 1989. *See* Memorandum for Alan Raul, General Counsel, Office of Management and Budget, from the Office of the Assistant Attorney General (April 14, 1989) (hereinafter ''OLC Memo'').[46] The OLC was asked by OMB to opine whether a general grant of regulatory authority to the EPA to ''control'' CFCs was sufficient to authorize an emissions fee or a cap-and-trade system, including auction, of tradable allowances. The statute authorized the EPA to issue regulations ''for the control of any substance, practice, process, or activity (or any combination thereof) which in his judgment may reasonably be anticipated to affect the stratosphere, especially ozone in the stratosphere, if such effect in the stratosphere may reasonably be anticipated to endanger public health.'' Former CAA 157(b) (as enacted in the 1977 CAA amendments). The Office of Legal Counsel concluded that this language—which it characterized as ''plain,'' ''unambiguous,'' and ''sweeping''—was sufficient to authorize the EPA to establish a cap-and-trade program with auction for CFCs. *See id.* at 7 (''It cannot seriously be argued that the use of economic incentives to regulate pollution is a novel or strange idea that could not have been anticipated by the authors of the Clean Air Act Amendments [of 1977].'') (citing multiple examples from the policy literature as early as E. Mishan, *The Costs of Economic Growth* (1967)). The OLC noted that as of 1977, ''Congress was cognizant of economic forms of regulation, did not prohibit them, but instead used general language

[45] The EPA is not aware of any case since at least the *Chevron* decision in which a trading program under the CAA was invalidated simply by virtue of being a trading program. The CAIR trading program was set aside by the DC Circuit because the court held it did not accomplish the objective of the Good Neighbor provision of the CAA, not because it used a trading approach per se. *North Carolina* v. *U.S. EPA,* 531 F.3d 896, 921 (D.C. Cir. 2008). More recently the Supreme Court upheld key portions of the CSAPR trading program that replaced CAIR in *EPA* v. *EME Homer City,* 134 S. Ct. 1584 (2014).

[46] A copy of this memorandum has been placed in the docket for this rulemaking.

permitting a wide scope of regulatory measures for the control of CFCs.'' To interpret the general authority of this section of the CAA as affirmatively prohibiting market incentives would be, in the OLC's words, to read into the statute the italicized clause ''regulations for the control [of CFCs] *by traditional command and control or specification standard methods,*'' *id.* at 9—a rewriting ''unwarranted in any case, but especially so where Congress was aware of economic methods of control and where such methods so ably serve the underlying purposes of the statute.'' *Id.*

By the time of the 1990 CAA Amendments, as discussed above, Congress was comfortable enough with the efficacy of market techniques that they were broadly authorized for use in SIPs and FIPs for NAAQS. *See* 42 U.S.C. 7410(a)(2)(A), 7602(y). In the wake of the 1990 Amendments, the EPA issued an ''Implementation Strategy for the Clean Air Act Amendments of 1990.'' [47] This Strategy included as one of nine overarching implementation principles, ''Market-based: Use of market-based approaches and other innovative strategies to creatively solve environmental problems.'' Further, it announced that the EPA would make ''full use of innovative market-based approaches,'' and that the agency will supplement traditional approaches with broader use of market incentives and other innovative approaches ''whenever possible.'' *Id.* at 3, 9.

Since the 1990 Amendments, the EPA has established three of its most robust trading programs—the Federal NO_X Budget Trading Program (65 FR 2674; January 18, 2000), the CAIR (71 FR 25328; April 28, 2006), and the CSAPR (76 FR 48208; August 8, 2011), under CAA section 110(a)(2)(D)(i)(I), relating to air pollution that causes nonattainment or interference with maintenance of air quality standards in downwind states.[48]

As noted in the rulemaking action for the final EGs, the EPA has instituted or authorized the use of emissions trading programs twice in the past under CAA section 111(d). The EPA authorized NO_X emissions averaging or trading within or between facilities under the Municipal Waste Combustors EGs in 1995. 60 FR 65387, 65402 (December 19, 1995) (codified at 40 CFR 60.33b(d)(1) and (2)). The EPA also developed a cap-and-trade system for mercury under CAA section 111(d) in the Clean Air Mercury Rule (CAMR). 70 FR 28606 (May 18, 2005). The EPA proposed a federal plan for trading that was identical in all relevant respects to the CAMR rule. 71 FR 77100 (December 22, 2006). However, CAMR was vacated by the D.C. Circuit on grounds unrelated to the establishment of a trading system for implementation before the CAMR federal plan could be finalized. *New Jersey* v. *EPA,* 517 F.3d 574 (D.C. Cir. 2008).[49]

The agency believes these legal and administrative precedents for federal trading programs under the CAA going back decades amply support its decision to propose two forms of emission trading as the method of implementation of the Clean Power Plan EGs in the federal plan. Notably, emissions trading is particularly appropriate with respect to a global pollutant such as CO_2 that is well-mixed in the atmosphere and does not have direct, acute health impacts due to inhalation at ambient levels.[50]

Finally, the Supreme Court has affirmed the breadth of the agency's discretion under CAA section 111(d) to select the method by which it would control CO_2 emissions from existing power plants. *See AEP* v. *Connecticut,* 131 S. Ct. 2527, 2538 (2011) (''Congress delegated to EPA the decision whether *and how* to regulate carbon-dioxide emissions from power plants.'') (emphasis added); *see also id.* at 2539 (''The appropriate amount of regulation in any particular GHG-producing sector cannot be prescribed in a vacuum: As with other questions of national or international policy, informed assessment of competing interests is required. Along with the environmental benefit potentially achievable, our Nation's energy needs and the possibility of economic disruption must weigh in the balance. The CAA entrusts such complex balancing to the EPA in the first instance, in combination with state regulators.'').

This proposal is guided by the relevant cases and the experiences of the agency in implementing the CAA trading programs discussed above. The EPA invites comment on this discussion and the agency's interpretation that CAA section 111(d)(2) authorizes the two approaches to a federal plan proposed here.

IV. Rate-Based Implementation Approach

A. Overview

The EPA's federal plan requirements for CO_2 from affected EGUs implement the EGs as previously discussed. In this federal plan and model rule proposal the EPA is proposing, as one option, rate-based emission standards (*i.e.,* the emission standard approach) for affected EGUs not covered by an approved state plan as specified in the Clean Power Plan. The EPA is proposing to apply the subcategorized emission rates in this federal plan proposal. These rate-based emission standards are consistent with, and would satisfy, the degree of emission limitation achieved by the BSER determination made in the final Clean Power Plan EGs, which included subcategorized CO_2 emission performance rates for affected EGUs to meet during the plan performance periods. An affected EGU subject to this federal plan will demonstrate compliance by achieving a stack emission rate less than or equal to the rate-based emission standard or by applying ERCs, acquired by the EGU, to its measured stack emissions rate. The application of ERCs by an affected EGU to comply with an emission standard has been determined in the final Clean Power Plan as a mechanism available to affected EGUs with a CO_2 emission rate greater than its respective performance rate to meet compliance obligations, see section VIII.K of the final EGs. Under a rate-based federal plan, the EPA would act as the state described in section VIII.C.1.a of the final EGs with the EPA acting as the issuer of ERCs, and otherwise implementing and enforcing the standards of performance for affected EGUs subject to the federal plan.

This section describes the proposed rate-based federal plan and model trading rule and how each would be designed and operated, consistent with the EGs. For the federal plan, the EPA is proposing to limit the issuance of ERCs to designated categories of affected EGUs and to RE resources and nuclear generation (from new capacity and incremental capacity uprates) that are

---

[47] U.S. EPA, Office of Air and Radiation, Implementation Strategy for the Clean Air Act Amendments of 1990 (Update, 1992) (July 1992), 400–K–92–004.

[48] The EPA notes that complications that arise with respect to assigning a ''significant contribution'' among upwind states for NAAQS pollutant levels in downwind states, and designing a trading regime that accomplishes Good Neighbor objectives, are not present with respect to CO_2, which is a global pollutant; emission reductions anywhere contribute to the environmental objective of addressing climate change.

[49] The CAMR program was vacated because the EPA had not made requisite findings under CAA section 112(c)(9) in delisting EGUs with respect to emissions of a hazardous air pollutants (HAP). No such procedural concern is present here with respect to CO_2, which is not a HAP under CAA section 112.

[50] We recognize that some commenters on the EGs raised concerns about the localized impacts that may occur from the potential for concentrations of co-pollutants associated with CO_2 emitted from affected EGUs. We address those concerns in the communities sections of the final EGs, at section IX, and in this preamble in section IX below.

measured by a revenue quality meter, rather than the full suite of options discussed in the EGs. The EPA requests comment on whether to limit the scope of the federal plan in this manner, and if not, what other sources of low- or zero-emitting electricity in federal plan states should also be eligible to generate ERCs for compliance purposes. For both the proposed federal plan and model rule, the EPA requests comment on which EM&V plan, measurement and verification (M&V) report, and verification report requirements should apply for each eligible resource. Further discussion of non-BSER measures that may be eligible to generate ERCs can be found in the Clean Power Plan and section IV.C.3 of this preamble. (The EPA is not reopening its determination of the BSER.)

B. Rate Goals

In the Clean Power Plan the EPA identified a rate-based ''emission standards'' approach as an approvable method for state plans to implement the final EGs. In this approach the requirements for compliance rest solely on affected EGUs in the form of federally enforceable emission standards expressed as a rate of emissions of CO_2 per unit of energy output. In the Clean Power Plan, the EPA established, through application of the BSER, separate CO_2 emission performance rates for affected EGUs in two subcategories. The two subcategories are natural gas-fired stationary combustion turbines (*i.e.,* natural gas combined cycle units, or NGCC units) and fossil fuel-fired EGUs (*i.e.,* utility boilers and IGCC).[51] The CO_2 emission performance rates set in the Clean Power Plan are reflected below in Table 6 of this preamble. The EPA is proposing to apply these rates in the rate-based federal plan as the emission standards for NGCC units, and SGUs, respectively. For a thorough discussion of affected EGU category-specific CO_2 emission performance rates and rationale, see section VI of the final EGs. These calculated standards and the premises that these standards are based on are not within the scope of comment in this rulemaking as they were finalized in the Clean Power Plan.

As discussed in section III.D of this preamble above, the EPA proposes to implement a compliance schedule for the rate-based federal plan with multi-year compliance periods as follows: A 3-year period (2022 through 2024), followed by a 3-year period (2025 through 2027), followed by a 2-year period (2028 and 2029), for the Interim Period; and, commencing in 2030, successive 2-year compliance periods for the Final Period. In the Clean Power Plan, the EPA established CO_2 emission performance rates for the subcategories of affected EGUs for the performance periods. The EPA proposes to use those emission performance rates promulgated in the Clean Power Plan as the rate-based emission standard for the respective EGUs that would become subject to this proposed federal plan if finalized. The EPA is not opening for comment the determinations made in the Clean Power Plan of each subcategorized CO_2 emission performance rates. The rate-based emission standards for respective EGU types are provided for convenience in Table 6 of this preamble.

The EPA is proposing to use a glide path during the Interim Period for EGUs to provide a smooth transition to the final compliance periods after 2030. This approach is established in the final EGs. In Table 6 of this preamble, the applicable standards for each interim compliance period are listed.

TABLE 6—GLIDE PATH INTERIM PERFORMANCE RATES (ADJUSTED OUTPUT-WEIGHTED-AVERAGE POUNDS OF CO_2 PER NET MWh FROM ALL AFFECTED FOSSIL FUEL-FIRED EGUS)

Technology	2022–2024 Compliance rate	2025–2027 Compliance rate	2028–2029 Compliance rate	Final rate
SGU or IGCC	1,671	1,500	1,380	1,305
Stationary combustion turbine	877	817	784	771

The EPA is using the subcategorized rates in the rate-based trading approach because it allows ERCs to be fungible across jurisdictional borders and provides an incentive structure, as compared to other rate-based approaches, that facilitates implementation of measures identified as part of the BSER. Using subcategorized rates allows for: (1) Consistently applied emission rates for power plants of different types; and (2) free trading of fungible ERCs among all affected EGUs subject to the federal plan and within the federal trading program. The EPA solicits comments on whether the subcategorized rate approach is the preferred rate-based approach for the federal plan and model trading rule.[52] If a subcategorized approach for a rate-based model rule and federal plan is not preferred by commenters, the EPA requests comment on the perceived benefits of an alternative rate or set of rates (*e.g.,* applying a uniform rate, *i.e.,* the state goal, to all affected units within the state as the EGUs' emission standard).

C. Crediting Mechanism

Under a rate-based emission standard approach in the federal plan, we are proposing that EGUs subject to the emission performance requirements for GHGs will either need to emit at or below their rate-based emission standard, or they will need to acquire ERCs to achieve compliance. An ERC is a tradable compliance unit representing one MWh of electric generation (or reduced electricity use) with zero associated CO_2 emissions. These ERCs may then be used to adjust the measured and reported CO_2 emission rate of an affected EGU when demonstrating compliance with a rate-based emission standard. For each ERC, one MWh is added to the denominator of the reported CO_2 emission rate, resulting in a lower adjusted CO_2 emission rate.

Under this proposed federal plan, ERCs will be issued by the EPA to four categories of entities: (1) Affected EGUs that perform at a rate below the applicable rate-based emission standard; (2) affected NGCC units for all generation (represents shifting generation from SGUs to NGCC units, as anticipated under Building Block 2); (3) new nuclear units and capacity uprates at existing nuclear units; and (4) RE providers that develop metered projects and programs whose results, in MWh, are quantified and verified according to

[51] For simplicity, affected utility boilers and IGCC will collectively be called ''steam generating units.''

[52] Note that the values of limits and determinations made as the BSER are not open for comment.

EM&V criteria as described below in section IV.D.8 of this preamble. We are also discussing in this preamble, requesting comment for the federal plan, and proposing for the model trading rule a potential fifth category: Other low- and zero-emitting non-BSER measures that are described in section IV.C.3 of this preamble. The concept of using an ERC as a crediting mechanism to meet compliance obligations is consistent with the Clean Power Plan EGs and is being adopted in this federal plan.[53]

Because the goal of this rulemaking is the actual reduction of CO_2 emissions, it is fundamental that ERCs represent the MWh of energy generation or savings they purport to represent. To this end, only valid ERCs that actually meet the standards articulated in this rule may be used to satisfy any aspect of compliance by an affected EGU with emission standards. The responsibility for the validity of the ERC rests with the affected EGU. Despite safeguards included in the structure of ERC issuance and tracking systems, such as the review of eligibility applications and M&V reports, and EPA issuance of ERCs, ERCs may be issued that do not, in fact, represent eligible zero-emission MWh as required in the EGs. A variety of situations may result in such improper ERC issuance, ranging from simple paperwork errors to outright fraud. The EPA requests comment on ways that the EPA could safeguard the validity of an ERC.

1. ERCs Generated and Owed Against a Standard

The number of ERCs generated or needed for surrender by an affected fossil fuel-fired EGU is based on the CO_2 emission rate of the EGU in comparison to a rate-based emission standard. The calculation of ERCs generated by an EGU or needed for compliance is the CO_2 stack emission rate of the EGU subtracted from the standard the EGU is subject to, and this value is subsequently divided by the standard the EGU is subject to. This value is a normalized quantity of how much better or worse the EGU is performing compared to its standard. The normalized value is weighted by multiplying the MWh electricity output from the EGU at that emission rate. This can be generically expressed as:

$$\text{ERCs} = \frac{(\text{EGU standard} - \text{EGU operating rate})}{\text{EGU standard}} * \text{EGU generation}$$

If the value calculated is positive, this indicates the number of ERCs that are being generated; conversely, a negative value indicates how many ERCs will need to be acquired to meet the unit's emission rate for that compliance period. ERCs will be issued on an annual basis to ERC providers (*i.e.,* entities generating ERCs via the ERC approval and issuance process detailed below). Surrender of ERCs for compliance by affected EGUs will not occur until the end of the compliance period as further described in section IV.D.10 of this preamble.

As an example, assume a steam EGU operating in the second interim compliance period is subject to a rate standard of 1,500 lbs CO_2/MWh. Assume it operates at 2,000 lbs CO_2/MWh, and also assume it generates 1 million MWh over a compliance period. Its total emission rate would be 2 billion lbs CO_2/1 million MWh. In order to achieve the emission standard, it would need to purchase 333,334 ERCs (rounded to the nearest higher integer). In essence, this quantity of ERCs represents the quantity of MWh that need to be added to the steam EGU's denominator (*i.e.,* generation, here, 1 million MWh), such that 2 billion pounds of CO_2 (total emissions), divided by total generation (*i.e.,* in this case, 1,333,334 MWh) equals the emission rate for compliance (1,500 lbs/MWh).

The discussion in this subsection builds on and applies the definition, benefits, use, and determination of using ERCs from the final EGs (section VIII of the final EGs). We invite comment on use of the approach just described as a method of implementation of a federal plan and a model trading rule, and we request comment on any alternatives to this approach that still fall within the established criteria described in the Clean Power Plan EGs. Comments that solely relate to determinations finalized in the EGs will be considered outside the scope of this proposed rule.

2. Incremental NGCC ERCs

Building Block 2 (BB2) of the BSER determination in the Clean Power Plan EGs describes shifting generation from SGUs to NGCC units because NGCC units generate electricity at a less carbon intensive rate. BB2 describes NGCC units generating at 75 percent of the unit's annual operating capacity. This level of generation, for most NGCC units, would represent an increase in annual generation from a 2012 baseline. For every hour of electricity generated by an NGCC unit beyond its 2012 baseline (*i.e.,* incremental generation), there is a corresponding emission reduction in the power system.[54] The EPA is proposing to reflect the emission reductions of BB2 by crediting all NGCC generation on a pro rata basis that reflects expected incremental NGCC generation to 75 percent capacity. This means that for every hour that an NGCC unit generates electricity, it will also generate a partial credit associated with the generation shift from fossil steam to NGCC units. The NGCC unit will generate a partial credit because the emission reductions associated with BB2 have been distributed on an hourly basis. A discussion on the concepts behind the distribution of emission reductions of incremental NGCC generation on an hourly basis can be found at the end of this subsection.

All affected NGCC generation will be credited, with ERCs, by a factor that represents the described emission reductions from incremental generation; ERCs credited in this way will be designated as Gas Shift ERCs (GS–ERCs) for clarity.[55] The collective sum of the GS–ERCs generated realizes the amount of emission reductions described in BB2 when 75 percent capacity is achieved. This incentive is not a requirement, however. If NGCC units do not collectively increase to 75 percent capacity or above, the lost opportunity for ERC generation simply will need to be achieved through other means (*e.g.,* emissions performance improvements at

[53] The use of ERCs and definition as a compliance mechanism to meet the BSER emission performance rates is established in section VIII.K of the final EGs.

[54] It is assumed that any increase in NGCC generation above 2012 levels is displacing fossil fuel-fired steam EGU generation.

[55] A GS–ERC is treated and represents the same value as an ERC, but has a compliance restriction that it can only be used by steam generating units and not by stationary combustion turbines for compliance obligations.

affected EGUs or additional RE generation). The amount of GS–ERCs the EPA proposes to be generated for every MWh of NGCC operation is set at a factor relating the amount of electricity generation that NGCC units collectively would generate at the level described in BB2 (*i.e.,* reaching 75 percent capacity) and the associated emission reductions. This means that fractional GS–ERCs are generated for every NGCC MWh and when the interconnect region collectively reaches the level that would be generated if all NGGC units in the region operated at a 75 percent capacity factor there will be an amount of GS–ERCs that correlates to the emission reductions anticipated under BB2 of the BSER. NGCC units are expected to be incentivized to reach this level of generation in part due to market demand for GS–ERCs. Thus, GS–ERCs have the potential to play an important role in the sector meeting compliance obligations.

The number of GS–ERCs that an NGCC unit generates is a combination of three factors. The first is the GS–ERC Emission Factor. This emission factor represents how much better an individual NGCC's emission rate is compared against the fossil steam standard. This measures the emission reductions because of the BB2 shift in generation. The SGU standard used as reference here is as described above in section IV.B of this preamble and established in the BSER determination from the EGs of the least stringent region [56] (*i.e.,* the region with the highest calculated rate-based emission standard for SGUs). The GS–ERC Emission Factor is expressed by taking the complement of the ratio of the NGCC standard to the fossil-steam standard. It can be summarized by the following expression:

$$\text{GS-ERC Emission Factor} = 1 - \frac{\text{NGCC Emission Rate}}{\text{Steam Standard}}$$

The second factor is the Incremental Generation Factor. This factor represents the distribution of the increased NGCC generation across all NGCC generation. In essence, it is prorating the incremental NGCC generation over all NGCC generation. The Incremental Generation Factor is calculated by taking the number of MWh beyond the 2012 baseline needed for the corresponding region to reach 75 percent NGCC generation capacity and dividing it by the MWh that is 75 percent NGCC generation capacity, giving a factor. This factor can be summarized by the following expression:

$$\text{Incremental Generation Factor} = 1 - \frac{\text{Regional 2012 NGCC Baseline}}{75\,\%\text{ NGCC Regional Capacity}}$$

The Incremental Generation Factor is a factor that the EPA will calculate and will be calculated for every compliance period based on the least stingent region's Incremental Generation Factor based on increased utilization of RE and its replacement of fossil fuel-fired generation (based on Building Block 3 of the Clean Power Plan EGs).[57] For the calculation of this factor the EPA is using the least stringent region for each compliance period and applying it for all GS–ERC calculations subject to the federal plan. The calculations for determinating the least stringent regional Incremental Generation Factor can be found in the GS–ERC TSD. Table 7 of this preamble presents the proposed values that would apply for all NGCC units to calculate the amount of issued GS–ERCs.

TABLE 7—INCREMENTAL GENERATION FACTORS FOR INTERIM AND FINAL COMPLIANCE PERIODS

Corresponding incremental generation factor			
Compliance period 1 2022–2024	Compliance period 2 2025–2027	Compliance period 3 2028–2029	2030–2031 and thereafter
0.22	0.32	0.28	0.26

The third factor in calculating an NGCC unit's generaton of GS–ERC is the NGCC Generation. The NGCC Generation is the total net energy output generation of the affected NGCC unit during the year that ERCs are being calculated. The three factors combine to make the following equation:

GS–ERCs = NGCC Generation * Incremental Generation Factor * GS–ERC Emission Factor

The GS–ERC equation above gives the number of GS–ERCs that an NGCC unit will generate. The Incremental Generation Factor and GS–ERC Emission Factor combine to make the GS–ERC generating rate for the NGCC unit. This functions by the Incremental Generation Factor prorating all incremental NGCC generation and the GS–ERC Emission Factor designating the proportion of the incremental NGCC generation that will generate ERCs. The GS–ERC generating rate multiplied by the total NGCC Generation gives the total GS–ERCs generated by the NGCC unit for the year.

The EPA is proposing this approach, which provides GS–ERCs for all affected EGU NGCC generation but at a fractional, pro rated level, using the three factors above, for several reasons. This approach has the benefit of

[56] The regions that are used in the Clean Power Plan EGs and for this proposal are the Eastern Interconnect, Western Interconnect, and Electric Reliability Council of Texas (ERCOT).

[57] Note that per the discussion in section VI of the final EGs, if the EPA had measured incremental NGCC generation for reassignment to fossil steam rate as the difference from the post building block three levels and full utilization, the post building block three levels would be used in the numerator here, resulting in a higher ''incremental generation factor'' and more ERCs for the same amount of NGCC generation.

allowing NGCC units to bid into the electricity market without having to adjust bids based on a projection of whether or not the NGCC unit will have generation incremental to its baseline in a given year. The proposed method also promotes the best performers within the NGCC subcategory by crediting them with a higher rate of generating GS–ERCs, as shown by the calculations above. The better the emission performance of an NGCC unit, the more GS–ERCs it is capable of earning per MWh. The proposed method also promotes and incentivizes all NGCC units, regardless of historical generation, to continue to operate at a greater capacity to replace steam generation. The EPA believes that this will allow for more fluidity in the market and flexibility for greater NGCC generation.

In the Clean Power Plan the BSER determination for subcategory rates is calculated by using the least stringent region and applying the standards from that region on a national level. The determination of the BSER in the final EGs was a one-time determination and is not being altered, updated, or changed here. Rather, in this preamble the EPA is proposing to use the same regions and to apply the least stringent components to an NGCC unit's GS–ERC calculation at a national level (*i.e.,* applying the GS–ERC calculation components that generate the most GS–ERCs for every MWh). The EPA solicits comment on applying the least stringent regional factor to calculate GS–ERCs for all affected NGCC units subject to the federal plan and model rule on a national level. Conversely, the EPA also requests comment on applying, for each region, its own regional GS–ERC generation rate. As proposed, the least stringent region could change from compliance period to compliance period. The EPA requests comment on whether a single ''least stringent'' region should be chosen and used for calculations or whether being ''least stringent'' should be evaluated on a compliance period by compliance period basis. The EPA also requests comment on whether ''least stringent'' should be evaluated on a year-to-year basis.

The EPA also requests comment on whether the GS–ERC Emission Factor should be calculated on a unit by unit basis (as currently proposed) or be calculated based on the least stringent region's baseline 2012 average emission rate. This will simplify the practice of calculating and distributing GS–ERC generation, but would not reward the better performing NGCC units within the subcategory. In the GS–ERC TSD, the EPA used the regions' average emission rate to calculate a factor that would credit GS–ERCs to all NGCC units subject to the federal plan. For 2030 and beyond, this value is based on the Eastern Interconnect and is 0.08 GS–ERCs/MWh. So for every MWh that an NGCC unit generates it would be issued 0.08 GS–ERCs and, if this were the approach the EPA proposed, this would apply to every NGCC unit that would be subject to the federal plan.

In the GS–ERC TSD, the spreadsheet can be manipulated to show what an individual NGCC unit's GS–ERC Emission Factor would be in the proposed method. This is done by adjusting the cell for a year's Average GS–ERC Emission Factor to account for the individual NGCC unit's emission rate instead of the average NGCC emission rate.

The calculation of GS–ERCs for an NGCC unit is independent of the calculation of ERCs generated or owed against the NGCC standard. It is possible that an NGCC unit will owe ERCs against its assigned emission standard for every MWh generated, but still be generating GS–ERCs. GS–ERCs may only be used to meet steam generation units' compliance obligations.

As an example, an NGCC unit is connected to the grid and generates 1 million MWh of electric output for the first year of the final performance period. During this year it emits 850 million lbs of CO_2 giving it an emission rate of 850 lbs CO_2/MWh. The NGCC unit is subject to a Final Period emission rate limit of 771 lbs CO_2/MWh. Since the NGCC unit is always subject to its NGCC rate-based emission standard of 771 lbs/MWh and it is operating at a rate above that standard it will owe non GS–ERCs for its own compliance. The ERCs owed are calculated by solving for the number of ERC MWh the NGCC unit will need to adjust its rate down to its emission rate limit. This is shown in the following equation:

$$850{,}000{,}000 \text{ lbs } CO_2/[1{,}000{,}000 \text{ MWh} + \text{ERC MWh}] = 771 \text{ lbs } CO_2/\text{MWh}$$

When that equation is solved for the number of ERC MWh needed, the NGCC unit would need to acquire 102,464 ERCs to adjust its emission rate to its rate-based emission standard.

Additionally, the GS–ERC Emission Factor for this NGCC unit is calculated by using 771 lbs CO_2/MWh for the NGCC emission rate and 1,404 lbs CO_2/MWh for the SGU emission standard in the equation described above.

$$\text{GS-ERC Emission Factor } = 1 - \frac{771 \text{ lbs/MWh}}{1{,}404 \text{ lbs/MWh}}$$

This calculation results in a GS–ERC Emission Factor of 0.45. This is only an example. Because the Incremental Generation Factor is calculated by the EPA, it can be found in the GS–ERC TSD and is proposed to be 0.26. By using the GS–ERC Emission Factor and Incremental Generation Factor calculated above with the NGCC unit's generation for the year, the number of GS–ERCs for this NGCC unit can be calculated.

$$0.45 * 0.26 * 1{,}000{,}000 = \text{GS–ERC}$$

The calculation results in 117 thousand GS–ERCs being generated. Because an NGCC unit cannot use the GS–ERCs it generates to meet its compliance obligations, this NGCC unit will both generate ERCs (117,000 GS–ERCs) and owe ERCs (102,464 non-GS–ERCs against NGCC standard). This NGCC unit may sell (or otherwise transfer) or bank its GS–ERCs. If a GS–ERC is sold, those proceeds may, in turn, be used to acquire non-GS–ERCs to satisfy the NGCC unit's compliance obligations.

A GS–ERC may not be used to meet an NGCC unit's compliance obligation because they are generated to reflect incremental NGCC generation replacing a SGU's generation. The calculation to derive a GS–ERC represents this generation shift. If a GS–ERC were to be used for compliance for an NGCC unit it would represent a shift from one NGCC unit to another, which serves little purpose in achieving emission reductions.

The EPA requests comment on the proposed approach and requests comment and suggestions on other approaches for existing NGCC units to generate GS–ERCs at all times. The EPA is considering this methodology that GS–ERCs are generated for all NGCC generation because it ensures that all existing NGCC units are encouraged to run at a greater capacity. The EPA requests comment on alternative methods to account for NGCC units generating GS–ERCs. Specifically, the EPA solicits comment on NGCC units generating GS–ERCs once a threshold of electric generation for the year is exceeded. This threshold is based on 2012 as a baseline and any NGCC generation beyond this threshold would be considered incremental generation. There are two different options to evaluate against a baseline. The first is on a unit-level, if an NGCC unit generates more than it did in 2012, all generation above the 2012 level (*i.e.,* incremental generation) is eligible to be credited with GS–ERCs. The other threshold option is to use a percentage threshold. Evaluated on a regional level, the 2012 baseline capacity percentage for NGCC units in the least stringent region is applied to all units. Each unit is considered to be incrementally generating after it exceeds the capacity percent and will be credited with GS–ERCs accordingly. The GS–ERCs in these instances are calculated by the following equation:

$$\text{GS-ERC} = \frac{(\text{Steam Standard} - \text{NGCC Emission Rate})}{\text{Steam Standard}} * \text{Incremental NGCC Generation}$$

This equation quantifies the reductions of the generation shift from fossil steam to NGCC units by the NGCC operating rate being evaluated against the fossil steam standard. For all incremental NGCC generation the NGCC operating rate is compared against two different standards: (1) The NGCC standard against which ERC generation is evaluated; and (2) the steam standard against which GS–ERC generation is evaluated. An evaluation against each standard is independent of one another and GS–ERCs, in this situation, are only available for fossil steam compliance purposes.

While having a baseline threshold for EGU generation to credit GS–ERCs against closely resembles the EPA's BSER determination, it enables a system in which GS–ERCs can be generated by replacing NGCC generation from one unit with NGCC generation from another. In this situation there is not necessarily any additional NGCC generation as a subcategory, but a shift in which NGCC units are generating electricity and to what degree. This allows for a situation in which GS–ERCs can be generated without achieving the anticipated reductions in CO_2 emissions.

The EPA also requests comment on whether a distinct type of ERC that comes with the proposed restrictions (*i.e.,* GS–ERCs) is necessary to maintain the integrity of the rate-based trading proposal. Comments regarding this section that solely relate to determinations finalized in the EGs will be considered outside the scope of this proposed rule.

3. Eligible Emission Reduction Measures for ERC Generation

Under the rate-based federal plan, the EPA is proposing to specify emission reduction measures used to adjust an emission rate that are eligible for ERC issuance under the federal plan. Specifically, the EPA is proposing that RE generation that meets the requirements for eligible resources in the EGs (as specified in section VIII.K of the final EGs), meets all other requirements related to ERC issuance in the EGs and this proposal, and falls into one of the following specific categories of RE resources (as specified in section V.E of the final EGs), are eligible to be issued ERCs: Wind, solar, geothermal power, and hydropower.[58] Further, the EPA is proposing for the federal plan that new nuclear units and capacity uprates at existing nuclear units that meet the requirements for eligible resources in the EGs (as specified in section VIII.K of the final EGs) and all other requirements related to ERC issuance in the EGs and this proposal are eligible to generate ERCs. Further, these RE and nuclear measures must have the ability to provide data from a revenue quality meter, a requirement that is further discussed in section IV.D.8 of this preamble.

The EPA is proposing the inclusion of these measure types in the federal plan for the following reasons. These technologies, with the exception of nuclear, are part of the quantification of RE generation potential for the BSER. Thus, they are included in the quantification of CO_2 emission performance rates and should be available to affected EGUs to meet their CO_2 emission performance rate under the federal plan. See the final EGs for details on the treatment of these measures in BSER (see section V.E of the final EGs). These RE technologies are also expected to be able to deploy on an economic basis during the compliance period, as discussed in the final EGs (see section V.E.6 of the final EGs). These technologies also provide the simplest and most timely path for EM&V implementation under a federal plan, because they can use their existing metering infrastructure to quantify generation and submit it for ERC issuance. A concern unique to federal plan implementation is the need for an ERC issuance process that can be implemented in a streamlined manner across many jurisdictions in the time frame allowed by the federal plan while still assuring a rigorous EM&V process. By limiting eligibility to measures that can be directly metered, a feasible federal plan process for ERC issuance across a potentially large number of jurisdictions is ensured. This approach would allow for easier determinations of compliance with the requirements for EM&V proposed in section IV.D.8 of this preamble below (see also section VIII.K.3 of the final EGs).

The agency requests comment on the inclusion of other emission reduction measures as eligible for ERC issuance under the rate-based federal plan. This may include other RE technologies not included above, such as distributed RE generation and various types of biomass. In this proposal, the EPA is also offering for comment a treatment option for biomass fuels, if it is included as an eligible measure under the federal plan (see below).

The EPA requests comment on the inclusion of various types of demand-side EE as eligible measures for ERC issuance under the federal plan, such as state and utility EE programs, project-based demand-side EE, state building codes, state appliance standards, and conservation voltage reduction. The agency also requests comment on the inclusion of CHP as an eligible measure under the federal plan. Later in this section, the agency has provided detailed requirements for the issuance of ERCs for CHP, and we request comment on these requirements for inclusion in the federal plan.

The EPA requests comment on the inclusion as eligible for ERC issuance under the federal plan of any other

[58] This treatment for RE as an eligible measure type is also proposed for the set-aside for RE that is part of the proposed mass-based implementation approach co-proposed in section V of this preamble as the federal plan, and all proposed aspects of the eligible measure types described in this section and the requests for comment included below also apply in the mass-based set-aside context. Incremental nuclear is not eligible for the RE set-aside. The set-aside method and the use of this eligibility treatment within it are specified in section V.D.3 of this preamble.

emission reduction measures beyond those mentioned here, as long as they meet the eligibility requirements outlined in the final EGs for rate-based crediting. For all of the above measures on which the EPA requests comment, the agency is particularly interested in comments on how EM&V methods can be implemented for these measures across applicable jurisdictions in the timeframe provided by this proposal in a way that is rigorous, straightforward, widely demonstrated, and in accordance with the EM&V requirements in this proposal, outlined in section IV.D.8 of this preamble, and within the requirements outlined in the final Guidelines (see section VIII.K.3 of the final EGs). It should also be noted that any eligible measure will be subject to the eligibility requirements outlined in this proposal and the final EGs, including the requirement that the measure be incremental to 2012.

The EPA acknowledges that as new technologies mature, there should be an avenue to add new technologies to this specified set of eligible measures under the federal plan. The agency requests comment on appropriate processes through which, after the federal plan is finalized, the EPA or stakeholders could demonstrate the appropriateness of new measure types and the EPA could evaluate and approve the demonstration so that a new measure type could be considered eligible for ERC issuance under the federal plan.

Under the rate-based model rule, the EPA is proposing that any emission reduction measure is eligible as long as the requirements for eligible resources in the final EGs (as specified in section VIII.K of the final EGs) and all other requirements related to ERC issuance under the model rule that are specified in the EGs and this proposal. In particular, these measures should be able to meet the requirements for EM&V as finalized in the final EGs section VIII.K and those proposed for the model rule in section IV.D.8 of this preamble. In this section, the EPA is also providing detailed requirements for CHP and waste heat power (WHP); these requirements are proposed under the model rule, and we request comment on their inclusion in the federal plan. We are requesting comment on the inclusion of biomass and an option for the treatment of biomass in both the proposed rate-based federal plan and proposed rate-based model rule.

As mentioned above, the EPA requests comment on the inclusion of biomass as an eligible measure for rate-based crediting. The EPA is also requesting comment on the following treatment option for biomass if biomass is included as an eligible measure. In the final EGs, the EPA recognizes that the use of some biomass-derived fuels can play an important role in controlling increases of CO_2 levels in the atmosphere (see section VIII.I.C of the final EGs). The use of some kinds of biomass has the potential to offer a wide range of environmental benefits, including carbon benefits. However these benefits can typically be realized only if biomass feedstocks are sourced responsibly and attributes of the carbon cycle related to the biomass feedstock are taken into account. Many states have already recognized the importance of waste-derived feedstocks via mandatory and voluntary programs supporting such efforts.[59] Some states have also acknowledged the potential role of certain forestry and agricultural industrial byproducts (such as black liquor) in energy production. Many states have also recognized the importance of forests and other lands for climate resilience and mitigation, and have developed a variety of sustainable forestry policies, biomass-related RE incentives and standards, and GHG accounting procedures.[60]

In addition to acknowledging such state programs, the EPA has undertaken a technical assessment of biogenic CO_2 emissions from stationary sources associated with the production, processing and use of biomass fuels. In November 2014, the agency released a second draft of the technical report, *Framework for Assessing Biogenic Carbon Dioxide for Stationary Sources.* The revised *Framework,* and the EPA's Science Advisory Board (SAB) peer review of the *2011 Draft Framework,* concluded that it is not scientifically valid to assume that all biogenic feedstocks are ''carbon neutral'' and that the net biogenic CO_2 atmospheric contribution of different biogenic feedstocks generally depends on various factors related to feedstock characteristics, production, processing and combustion practices, and, in some cases, what would happen to that feedstock and the related biogenic emissions if not used for energy production.[61] The EPA is engaging in a second round of targeted peer review on the revised *Framework* with the SAB in 2015.[62] Information in the revised *Framework* and the second SAB peer review process, including stakeholder comments, will assist the EPA in assessing potential qualified biomass feedstocks in federal plan applications.

If biomass is included as an eligible measure, we are taking comment on an option for biomass treatment under the rate-based federal plan, which would also potentially apply to eligible generation under the proposed mass-based model trading rule allowance set-aside and to the calculation of covered emissions for affected EGUs that are co-firing biomass.

This option offered for comment is to specify a list of pre-approved qualified biomass fuels. For example, the EPA could recognize the CO_2 and climate policy benefits of waste-derived feedstocks (*e.g.,* landfill gas) and certain industrial byproduct feedstocks (*e.g.,* black liquor or other forestry and agricultural industrial byproducts with no alternative markets). As another example, the EPA could also recognize biomass feedstocks from sustainably managed forest lands, provided that these feedstocks meet certain requirements such as demonstration that the feedstock is sourced from sustainably managed lands (for example, feedstocks from forest lands with sustainable practices like improved management to increase carbon sequestration benefits) and therefore helps control increases of CO_2 in the atmosphere. The pre-approved qualified biomass feedstocks list could be amended in the future as the science related to biogenic CO_2 emissions assessments evolves. The EPA asks for

[59] Types of waste-derived biogenic feedstocks may include: Landfill gas generated through the decomposition of municipal solid waste (MSW) in a landfill; biogas generated from the decomposition of livestock waste, biogenic MSW, and/or other food waste in an anaerobic digester; biogas generated through the treatment of waste water, due to the anaerobic decomposition of biological materials; livestock waste; and the biogenic fraction of MSW at waste-to-energy facilities (as discussed in section VIII.I.2.C of the final EGs).

[60] Some states, for example Oregon and California, have programs that recognize the multiple benefits that forests provide, including biodiversity and ecosystem services protection as well as climate change mitigation through carbon storage. Others, like California's Forest Practice Regulations, support sustained production of high-quality timber while considering ecological, economic and social values. Several states focus on sustainable bioenergy, as seen with the sustainability requirements for eligible biomass in the Massachusetts renewable portfolio standard (RPS), which, among other requirements, limits old growth forest harvests.

[61] Specifically, the SAB found that ''There are circumstances in which biomass is grown, harvested and combusted in a carbon neutral fashion but carbon neutrality is not an appropriate a priori assumption; it is a conclusion that should be reached only after considering a particular feedstock's production and consumption cycle. There is considerable heterogeneity in feedstock types, sources and production methods and thus net biogenic carbon emissions will vary considerably. Of course, biogenic feedstocks that displace fossil fuels do not have to be carbon neutral to be better than fossil fuels in terms of their climate impact.'' *http://www.epa.gov/climatechange/ghgemissions/biogenic-emissions.html.*

[62] *http://www.epa.gov/sab.*

comment on whether to include a provision that allows sources to seek approval for other types of biomass to be added to the pre-approved list and what that process would entail. For example, this process could include consideration of the production, processing and use of forest- and agriculture-derived biomass fuels and related CO_2 benefits.

The EPA also requests comment on options for how EGUs would demonstrate that feedstocks meet the requirements to be accepted as a pre-approved qualified biomass feedstocks. These requirements could include demonstration of certification or verification of practices that are additional to other monitoring, reporting and EM&V requirements discussed in this proposal, such as provision of sufficient credible analysis of carbon benefits, third party verification and/or certification, or a determination of the net biogenic CO_2 effects related to the production, processing and use of the feedstock.

The EPA requests broad comment on the types of qualified biomass feedstocks that should be specified in the final model rule, if any. We request comment on the methods that we should specify in the final model rule for the measurement of the associated biogenic CO_2 for such feedstocks, as well as what other requirements we should specify in the final model rule related to biomass. Specifically, we seek comment on the level of detail provided and whether more or less detail (and what detail) should be included in the final model rule. We request comment on any other requirements that should be included in the final model rule regarding EM&V for qualified biomass. Discussion of the biomass EM&V requirements in the rate-based model rule can be found in section IV.D.8 of this preamble below.

The eligibility requirements for ERC resources discussed in this section meet the requirements outlined in the final EGs (see section VIII.K.2 of the final EGs). The agency in this proposal is including in the regulatory text for the model rule language related to the crediting of these other potential ERC resources, even though they are not being proposed as a part of the federal plan. Our intent is to provide states further direction through the model rule on how states may include this broader set of ERC-generating resources in a rate-based plan. To reduce confusion over the applicability of these provisions, the agency has added a note in the regulatory text to clarify that these resources, and provisions throughout the proposed subpart that are related to those resources, are not applicable in the case of a federal plan. Rather they are proposed as part of the model trading rule only. However, again, the agency requests comment on the inclusion of these resources in the federal plan.

The EPA is proposing with respect to the rate-based model rule that CHP units are eligible to generate ERCs. With respect to the federal plan, the EPA requests comment on the incorporation of non-affected CHP units. Electric generation from non-affected CHP units [63] may be used to adjust the CO_2 emission rate of an affected EGU, as CHP units are low-emitting electric generating resources that can replace generation from affected EGUs. Electrical generation from non-affected CHP units that meet the eligibility criteria under section VIII.K.1.a of the Clean Power Plan preamble can be used to adjust the reported CO_2 emission rate of an affected EGU.

The electrical generation from a non-affected CHP unit that can be used to adjust the CO_2 emission rate of an affected EGU must be calculated in accordance with the method specified in this section. The CHP unit's electrical output is prorated based on the CO_2 emission rate of the electrical output associated with the CHP unit (a CHP unit's ''incremental CO_2 emission rate'') compared to a reference CO_2 emission rate.[64] This ''incremental CO_2 emission rate'' related to the electric generation from the CHP unit would be relative to the applicable CO_2 rate-based emission standard for affected EGUs in the state and would be limited to values between 0 and 1. The CHP unit's electrical output is prorated as follows:

Prorated MWh = (1-incremental CHP electrical emission rate/applicable affected EGU rate-based emission standard)* CHP MWh output

Where the ratio is limited to values between 0 and 1.

The CHP electrical CO_2 emission rate is the net emission rate when the CHP unit's CO_2 emissions related to its thermal output are deducted from the CHP unit's total CO_2 emissions. The CHP electrical CO_2 emission rate is derived as follows:

CHP electrical CO_2 emission rate = [CHP fuel input [65] * fuel emission factor [66] − (UTO/boiler efficiency) * fuel emission factor]/CHP electrical MWh

Where UTO is the useful thermal output from a counterfactual industrial boiler that would have existed to meet thermal load in the absence of the CHP unit.

This accounting approach takes into account the fact that a non-affected CHP unit is a fossil fuel-fired emission source, as well as the fact that the incremental CO_2 emissions related to electrical generation from a non-affected CHP unit are typically very low. To generate ERCs for CHP, the CHP Electrical CO_2 Emission Rate that is calculated (from above) is applied against the applicable affected EGU standards in the same fashion as described in section IV.C.1 of this preamble. The low CO_2 emission rate for electrical generation from a non-affected CHP unit is a product of both the fact that CHP units are typically very thermally efficient and the fact that a portion of the CO_2 emissions from a non-affected CHP unit would have occurred anyway from an industrial boiler used to meet the thermal load in the absence of the CHP unit. In contrast, the CHP unit also provides the benefit of electricity generation while resulting in very low incremental CO_2 emissions beyond what would have been emitted by an industrial boiler. As a result, the accounting method does not presume that emission reductions occur outside the electric power sector, but instead only accounts for the CO_2 emissions related to the electrical production from a CHP unit that is used to substitute for electrical generation from affected EGUs.

The EPA is proposing with respect to the rate-based model rule that WHP units are eligible to generate ERCs. With respect to the federal plan, the EPA requests comment on the incorporation of non-affected WHP units. WHP units that meet the eligibility criteria under section VIII.K.1 of the Clean Power Plan preamble may be used to adjust the CO_2 emission rate of an affected EGU. There are several types of WHP units. There are units, also referred to as bottoming cycle CHP units, where the fuel is first used to provide thermal energy for an industrial process and the waste heat

[63] The accounting treatment described in this section is for a ''topping cycle'' CHP unit. A topping cycle CHP unit refers to a configuration where fuel is first used to generate electricity and then heat is recovered from the electric generation process to provide additional useful thermal and/or mechanical energy. A CHP unit can also be configured as a ''bottoming cycle'' unit. In a bottoming cycle CHP unit, fuel is first used to provide thermal energy for an industrial process and the waste heat from that process is then used to generate electricity. Some waste heat power (WHP) units are also bottoming cycle units and the accounting treatment for bottoming cycle CHP units is provided with the WHP description below.

[64] The applicable CO_2 rate-based emission standard is in Table 6 of this preamble.

[65] This term generally represents the thermal energy associated with the total fuel input.

[66] The fuel emission factor can be determined through 40 CFR part 75 Appendix G.

from that process is then used to generate electricity.[67] There are also WHP units where the waste heat from the initial combustion process is used to generate additional power. Under both configurations, unless the WHP unit supplements waste heat with fossil fuel use, there is no additional fossil fuel used to generate this additional power. As a result, there are no incremental CO_2 emissions associated with that additional power generation. As a result, the incremental electric generation output from the WHP units could be considered non-emitting, for the purposes of meeting the EGs, and the MWh of electrical output could be used to adjust the CO_2 emission rate of an affected EGU.[68] The MWh of electrical output from a WHP unit that can be recognized may not exceed the MWh of industrial or other thermal load that is being met by the WHP unit, prior to the generation of electricity.[69] In addition, where fossil fuel is used to supplement waste heat in a WHP application, the EPA requests comment on what provisions to include in the final model rule to prorate the proportion of fossil fuel heat input to total heat input that is used by the WHP unit to generate electricity. The EPA also solicits comments on other potential accounting mechanisms for WHP. As noted above, the EPA requests comment incorporating WHP as an ERC generating resource for the federal plan.

D. ERC Tracking and Compliance Operations

The EPA proposes that the rate-based federal trading program use the agency's already-existing Allowance Tracking and Compliance System (ATCS). Under the proposed rate-based trading program, the federal trading program would be maintained in the EPA's existing data system. The ATCS would be used to track the trading of ERCs held by affected EGUs, as well as ERCs held by other entities. Specifically, the ATCS would track the generation of ERCs, holdings of ERCs in compliance accounts (*i.e.,* accounts for affected EGUs) and general accounts (*i.e.,* accounts for other entities and for affected EGUs, including affected EGUs that are under a ready-for-interstate-trading state plan), deduction of ERCs for compliance purposes, and transfers of ERCs between accounts. The primary role of the ATCS is to provide an efficient, automated means for covered sources to comply, and for the EPA to determine whether covered sources are complying with the emission rate standards. The ATCS would also provide data to the ERCs market and the public, including a record of ownership of ERCs, dates of ERC issuance, ERC transfers, buyer and seller information, serial numbers of ERCs transferred, emissions data, and compliance information. This information would be publicly available on the EPA's Web site and in annual progress reports. The ATCS and the EPA would provide all required elements of a qualified ERC tracking system as described in section VIII of the final EGs.

In the subsections that follow, the mechanisms by which a rate-based trading program would be implemented and administered are detailed. The EPA requests comment on each component of the trading system that is proposed in this preamble and the associated model rule, the trading program as a whole, and specifically requests comment on means to expedite the process of issuing ERCs, any minimum and maximum periods for which ERCs should be issued (*e.g.,* monthly, quarterly, annually), and any means to ensure that the ERCs issued meet the requirements of the EGs and these proposed rules. The rate-based federal plan and model rule borrow many concepts from other successful trading programs, and the agency is interested in receiving additional information through comments on successful implementation of similar programs.

1. Designated Representatives and Alternate Designated Representatives

This section establishes the procedures for certifying and authorizing the designated representative, and alternate designated representative, of the owners and operators of the affected EGU and for changing the designated representative and alternate designated representative. These sections also describe the designated representative's and alternate designated representative's responsibilities and the process through which he or she could delegate to an agent the authority to make electronic submissions to the Administrator. These provisions would be patterned after the provisions concerning designated representatives and alternates in prior EPA-administered trading programs.

The designated representative would be the individual authorized to represent the owners and operators of each affected EGU in matters pertaining to the rate-based trading program. One alternate designated representative could be selected to act on behalf of, and legally bind, the designated representative and, thus, the owners and operators. Because the actions of the designated representative and alternate would legally bind the owners and operators, the designated representative and alternate would have to submit a certificate of representation certifying that each was selected by an agreement binding on all such owners and operators and was authorized to act on their behalf.

The designated representative and alternate would be authorized upon receipt by the Administrator of the certificate of representation. This document, in a format prescribed by the Administrator, would include: Specified identifying information for the covered source and covered EGUs at the source and for the designated representative and alternate; the name of every owner and operator of the affected EGU; and certification language and signatures of the designated representative and alternate. All submissions (*e.g.,* monitoring plans, monitoring system certifications, and allowance transfers) for an affected EGU would have to be submitted, signed, and certified by the designated representative or alternate. Further, upon receipt of a complete certificate of representation, the Administrator would establish a compliance account in the ATCS for the affected EGU involved.

In order to change the designated representative or alternate, a new certificate of representation would have to be received by the Administrator. A new certificate of representation would also have to be submitted to reflect changes in the owners and operators of the affected EGU involved. However, new owners and operators would be bound by the existing certificate of representation even in the absence of such a submission.

In addition to the flexibility provided by allowing an alternate to act for the designated representative (*e.g.,* in circumstances where the designated representative might be unavailable), additional flexibility would be provided by allowing the designated representative and alternate to delegate authority to make electronic submissions on his or her behalf. The designated representative and alternate could designate agents to submit

[67] In such a configuration, the waste heat stream could also be generated from a mechanical process, such as at natural gas pipeline compressors.

[68] This only applies where no additional fossil fuel is used to supplement the use of waste heat in a WHP facility. Where fossil fuel is used to supplement waste heat in a WHP application, MWh of electrical generation that can be used to adjust the CO_2 emission rate of an affected EGU must be prorated based on the proportion of fossil fuel heat input to total heat input that is used by the WHP unit to generate electricity.

[69] This limitation prevents oversizing the thermal output of a WHP unit to exceed the useful industrial or other thermal load it is meeting, prior to generation of electricity.

electronically certain specified documents. The previously-described requirements for designated representatives and alternates would provide regulated entities with flexibility in assigning responsibilities under the rate-based trading program, while ensuring accountability by owners and operators and simplifying the administration of the proposed rate-based trading program.

2. ERC Tracking and Compliance System

The rate-based trading program rules establish the procedures and requirements for using and operating the ATCS (which is the electronic data system through which the Administrator would handle ERC issuance, holding, transfer, and deduction), and for determining compliance with the ERC-holding requirements in an efficient and transparent manner. The ATCS provides a record of ownership, dates of ERC transfers, buyer and seller information, origin of ERCs, the serial numbers of ERCs transferred, and ERC type (*i.e.,* if it is a GS–ERC or not). ERC price information would not be included in the ATCS. The EPA's experience is that private parties (*e.g.,* brokers) are in a better position to obtain and disseminate timely, accurate price information than the EPA. For example, because not all ERC transfers are immediately reported to the Administrator, the Administrator would not be able to ensure that any reported price information associated with the transfers would reflect current market prices.

3. Tracking System Requirements

This federal plan and model rule's proposed tracking system and tracking systems that will be presumptively approvable for state plans fufill the criteria set forth in the final EGs. The EPA's tracking system includes provisions to ensure that ERCs issued to any eligible entity are properly tracked from issuance to submission by affected EGUs for compliance (where ERCs are ''surrendered'' by the owner or operator of an affected EGU and ''retired'' or ''cancelled'' by the Administrator or administering state regulatory body), to ensure they are used only once to meet a regulatory obligation. This is addressed through specified requirements for tracking system account holders, ERC issuance, ERC transfers among accounts, compliance true-up for affected EGUs,[70] and an accompanying tracking system infrastructure design. Each issued ERC will have a unique identifier (*i.e.,* serial number) and the tracking system will provide traceability of issued ERCs back to the program or project for which they were issued.

The EPA received a number of comments from states and stakeholders on the Clean Power Plan about the value of the EPA's support in developing and/or administering tracking systems to support state administration of rate-based emission trading systems. As described above in section III.A of this preamble, the EPA is proposing, as part of both types of model trading rules, a federal trading platform that would allow state plans that are ready-for-interstate-trading to operate through a program in which the EPA provides the tracking and compliance system. This system will meet the requirements of the Clean Power Plan.

4. Compliance and General Accounts

This section describes two types of ATCS accounts: Compliance accounts, which would be established by the Administrator for each affected EGU upon receipt of the certificate of representation for the source; and general accounts, which could be established by any entity upon receipt by the Administrator of an application for a general account. A compliance account would be the account in which any ERCs used by the affected EGU for compliance with the emissions limitations would have to be held until retired for compliance.

General accounts could be used by any person or group for holding or trading ERCs. However, ERCs could not be used for compliance with emissions limitations so long as the ERCs were held in, and not properly and timely transferred out of, a general account. To open a general account, a person or group would be required to submit an application for a general account, which would be similar in many ways to a certificate of representation. The application would include, in a format to be prescribed by the Administrator: The name and identifying information of the individual who would be the authorized account representative and of any individual who would be the alternate authorized account representative; an identifying name for the account; the names of all persons with an ownership interest with the respect to allowances held in the account; and certification language and signatures of the authorized account representative and alternate. The authorized account representative and alternate would be authorized upon receipt of the application by the Administrator. The provisions for changing the authorized account representative and alternate, for changing the application to take account of changes in the persons having an ownership interest with respect to ERCs, and for delegating authority to make electronic submissions would be analogous to those applicable to comparable matters for designated representatives and alternates. The EPA requests comment on these compliance mechanisms.

5. Compliance Demonstration

The EPA proposes that affected EGUs subject to this federal plan are required to meet compliance obligations by November 1 of the year following the end of the compliance period. For an affected EGU to meet its compliance obligations its average stack emission rate over the compliance period must be at or below its applicable rate standard, or the affected EGU must use ERCs to adjust its average stack emission rate to be at or below its applicable rate standard. An EGU's average emission rate over the compliance period will be calculated based on submitted data to ATCS. The compliance period average would be calculated by taking the measured CO_2 mass in units of pounds (lbs) summed over the compliance period for an affected EGU and dividing it by the total net energy output over the compliance period for that affected EGU in units of MWh.[71] This averaged emission rate will be compared to the emissions standards that the affected EGU is subject to during the corresponding compliance period. Accordingly, and if necessary, the appropriate number of ERCs will be retired from the affected EGU's compliance account to adjust the emission rate of the affected EGU to be equal to the emission standard. The discussion of using ERCs for compliance is found in section IV.D.10 of this preamble.

6. Recordation of ERC Generation and ERC Issuance

The EPA proposes to issue ERCs for ERC generating entities once per year. Thus, in a 3-year compliance period, for instance, there would be three points at which the agency issues ERCs. After

[70] ''Compliance true-up'' refers to ERC submission by an owner or operator of an affected EGU to adjust a reported CO_2 emission rate, and determination of whether the adjusted rate is equal to or lower than the applicable rate-based emission limit.

[71] Note that affected EGUs will submit these values to the EPA and the values will go through a transparent review process.

each calendar year, the EPA would calculate the ERCs generated for affected EGU and non-EGU ERC generators based on data submitted to the EPA through the Emissions Collection and Monitoring Plan System (ECMPS). These calculated ERC quantities would be proposed as part of a Notice of Data Availability (NODA) with a 30-day comment period. Subsequently, the EPA would finalize this NODA and issue ERCs in accordance with the NODA, with tracking and serial numbers. For affected EGUs with compliance accounts, the ERCs would be issued to these. For entities without compliance accounts, the EPA would issue ERCs to an entity's general account. The timing for issuing ERCs would be consistent with existing programs, and the EPA believes there is value in consistency. However, we solicit comment on the annual issuance of ERCs and whether issuance should occur at different intervals (*e.g.,* quarterly, biannually, or other time frames). The EPA requests justification along with corresponding comments regarding ERC-issuance intervals. We request comment on how reporting and recordkeeping requirements could be minimized, particularly for small entities, to the extent possible under the statute and existing regulations.

a. *Issuance of ERCs to Affected EGUs.* Following the determination of the number of ERCs an affected EGU is eligible to receive, based on an affected EGU's reported CO_2 emission rate compared to a specified reference rate,[72] the EPA will issue those ERCs into the affected EGU's compliance account in ATCS. The issuance will occur annually through the NODA process. ERCs will have a unique serial number, tracking number, and will distinguish ERC type (*i.e.,* if it is BB2 or not) when issued to an affected EGU.

b. *Issuance of ERCs for Measures Used to Adjust an Emission Rate.* In the final EGs, the EPA has specified requirements for an ERC issuance process for the quantification and verification of measures used to adjust an emission rate that provide the necessary rigor and transparency while being efficient and streamlined. This is the intent of the federal plan as well, where there is a particular concern with implementing a streamlined and efficient federal process for ERC issuance across federal plan states. As required in the final EGs, we are proposing a two-step application process to the federal plan tracking systems for ERCs that allows for project approval to take place prior to the performance period, and makes the issuance of ERCs as quick and efficient as possible after generation has been quantified and verified, while still assuring a rigorous approval process. For the first step in the ERC issuance application process, the EPA proposes that RE and nuclear generation providers submit to the EPA or its designated agent an eligibility application for EPA approval, demonstrating that the project is eligible for the issuance of credits, including an EM&V plan that meets EPA requirements. The EPA requests comment on all aspects of the proposed ERC issuance process. The EPA also requests comment on how an ERC issuance process would apply to emission reduction measures for which we are requesting comment regarding their eligibility for ERC issuance under the federal plan, including types of RE not covered by the federal plan, demand-side EE, CHP, WHP, biomass, and any other measure that could be considered eligible under the final guidelines.

The following are proposed required components of the eligibility application, as specified for these measures in the final EGs:

(1) The EPA proposes that the federal plan will require that providers must show that the generation they would be providing to the federal plan system for ERC issuance is only being credited in the federal plan, and will not be submitted for ERC issuance in any other rate-based crediting system in any other state. As discussed in section IV.C. of this preamble, we are proposing that states with rate-based emission standards plans that have eligibility and EM&V requirements compatible with the federal plan would have the opportunity to participate in the federal plan trading systems, and create a shared pool of creditable reductions, in which case credits approved by such states would be eligible for use by affected EGUs in the federal plan.

(2) The provider must show that the project is using an eligible RE or nuclear resource. Specific requirements are proposed in section IV.C of this preamble.

(3) The provider must show that the project has an EM&V plan that meets the federal plan requirements. Proposed requirements specific to the federal plan are proposed in section IV.D.8 of this preamble. As specified in section IV.D.8 of this preamble, we request comment on whether nuclear energy resources should be subject to the same EM&V requirements as RE resources, and if not, we request comment on the EM&V requirements to which nuclear energy resources should be subject.

(4) There are special conditions if the provider is located in a state with a mass-based plan. For eligible RE capacity, the provider can only be credited in a rate-based state or rate-based multi-state system if the provider can demonstrate that the generation was produced to meet electricity load in a state with a rate-based plan. The EPA is proposing that an RE provider can make this demonstration by providing documentation of a power purchase agreement or delivery contract from the rate-based state and show that the measure was treated as a generation resource used to serve regional load that included the rate-based state. For incremental nuclear capacity, no provider in a state with a mass-based plan can be eligible for ERC issuance in a rate-based state. This requirement and the justification for its inclusion is further discussed in section III.A of this preamble on Interstate Effects and also discussed in the Interstate Effects section of the final EGs (see sections VIII.K.1 and VIII.L). The EPA is proposing that there would be no other geographic limitation on the location of the providers of RE and incremental nuclear generation submitted for ERC issuance under the rate-based federal plan approach.

(5) This application must include an independent third-party verifier's review and approval of the eligibility requirements, as is reflected in EM&V requirements for the final guidelines, and specified as part of the proposed federal plan EM&V requirements in section IV.D.8 of this preamble.

We request comment on each criterion of the eligibility application described herein and in the proposed model rule, for each eligible resource. Specifically, we seek comment on the substantive content of the criteria, and we seek comment on the level of detail provided and whether more or less detail (and what detail) should be included in the final model rule.

The EPA is proposing that ERCs would be tracked in the ATCS. Additionally, the EPA is proposing that the agency would establish a complementary tracking system for the ERC issuance process. It would provide for transparent access to RE project and program eligibility applications and regulatory approvals as well as information on the activities of accredited third party verifiers (third party verifiers are further discussed in section IV.D.7 of this preamble), as well for the public to be able to generate reports based on this information.

The agency is proposing that the project eligibility applications would be accepted after the finalization of the federal plan and prior to the first compliance period, as soon as the agency is able to establish an application process, and that applications would be accepted on an annual basis. The agency requests comment on whether a quarterly or biannual application process is more appropriate. These applications would be accepted through the entirety of all compliance periods. The EPA will review and approve the project applications. It is proposed that the EPA

[72] As described in section IV.C.1 of this preamble.

may designate an agent to coordinate the project application process and assist with review of applications.

For the second step in the credit issuance application process, the EPA proposes that providers submit an M&V report to the EPA, or its designated agent, prior to the EPA's issuance of ERCs. This can only occur after the approval of a project application, the RE has been generated, and necessary EM&V has been completed.

The following are proposed required components of the M&V Report:

(1) Documentation of completed EM&V in accordance with the EM&V plan submitted by the RE or nuclear provider, including quantification of the MWh of generation to be credited and verification of their creation.

(2) Documentation that the generation has not been submitted for crediting under any other federal or state plan, including to another rate-based credit tracking system.

(3) Documentation that the MWh resulted from RE or incremental nuclear capacity eligible for crediting under the federal plan requirements and in accordance with final EGs. This documentation should note if the MWh are from an RE project located in a state with a mass-based plan, and show if the generation is approved to be eligible for ERC issuance under the federal plan. See above geographic eligibility discussion and section III.A of this preamble for specifics on the required demonstration for this type of RE generation. As discussed in that section, this option is proposed to not be available to incremental nuclear capacity located in a state with a mass-based plan.

(4) This application must include a verification report from an independent third-party verifier, submitted after the verifier's review and approval of the eligibility application, as is reflected in EM&V requirements for the final guidelines, and specified as part of proposed federal plan EM&V requirements described below and included in detail in the proposed model rule.

If the application meets these requirements, pursuant to review by the EPA or its designated agent, ERCs will be issued to the provider by the EPA through the ATCS. The specific steps of the process by which an eligible resource seeks ERCs, and by which an affected EGU may use ERCs in its compliance demonstration, are described in the proposed model rule. One of the steps requires the proponent to register for a general account in the EPA tracking system where the ERCs would be recorded. See 40 CFR 62.16515 for the requirements to establish a general account. While EPA is proposing to allow eligible resources to use a general account to receive any ERCs issued under this section, the EPA requests comment on extending the designated representative provisions in 40 CFR 62.16485 to eligible resources instead of the general account provisions. Requiring eligible resources to submit information similar to that collected in the certificate of representation in 40 CFR 62.16500 and to appoint a designated representative to act on behalf of all owners/operators for all projects requesting ERCs may improve the EM&V process by making the eligible resources more accountable.

Because it is critical to the integrity of an ERC that it represents the actual MWh of energy generated or saved that it purports to represent, and as required in the EGs for state plans, the federal plan and model rule include provisions to address error correction (*i.e.,* mechanisms to adjust the number of ERCs issued based on all form of errors, *e.g.,* clerical errors, over- and under-statements, material inconsistency with rule provisions, fraud, etc.). In addition, the federal plan and model rule include provisions that provide that, at any time for cause, the EPA may temporarily or permanently revoke the qualification status of eligible resources from being issued ERCs for at least the duration it does not meet the requirements for being issued ERCs and independent verifiers from providing verification services for at least the duration it does not meet the requirements of the state plan. For the federal plan, as discussed in section III.I of this preamble above, we propose to use the administrative appeals process set forth 40 CFR part 78 to address party-specific disputes concerning the issuance or validity of ERCs. States may adopt a similar procedural and substantive process at the state level to enable them to rescind or withhold approval of specific credits. We request comment on the content of each of these provisions in the model rule, and specifically seek comment on whether the model rule should include different or additional details related to either procedure or substance for error correction and the revocation of the qualification status of an eligible resource or independent verifier.

The agency is proposing that M&V reports will be accepted starting before the beginning of the first compliance period (January 1, 2022), through an application process the agency will establish and administer, and that applications will be accepted on an annual basis. These applications will be accepted through the entirety of all compliance periods. The EPA will review and approve M&V reports, and may designate an agent to coordinate and assist with M&V reports. The EPA is proposing that it will issue ERCs for a given year no later than 6 months after the end of the relevant year. This amount of time may be necessary to accommodate the ERC issuance process, including necessary EM&V. The overall proposed schedule for trading and true-up has been constructed to allow for this period of time for EM&V after the compliance period.

For purposes of the proposed rate-based federal plan, the EPA proposes to implement the CEIP on behalf of a state by issuing early action ERCs for eligible actions located in or benefitting that state that are implemented after September 6, 2018 and that generate zero-emitting MWh or reduce energy demand in 2020 and/or 2021.[73] The EPA intends to implement the program in a way that maintains the stringency of the rate-based emission standards for affected EGUs in the compliance periods established in this rule. For the purposes of the rate-based federal plan, the EPA is proposing to award early action ERCs to two types of eligible projects, as listed below. The rationale for including these projects is included in section VIII.B.2 of the final EGs.

- RE investments that generate metered MWh from any type of wind or solar resources; and
- Demand-side EE programs and measures implemented in low-income communities that result in quantified and verified electricity savings (MWh).

The EPA proposes the following framework to implement the CEIP in the rate-based federal plan. First, the EPA proposes to implement a mechanism for issuing early action ERCs for eligible RE projects that commence construction and eligeible EE projects that commence implementation after September 6, 2018 and that generate zero-emitting MWh or reduce end-use energy demand during 2020 and/or 2021. These projects must be located in or benefit the state on whose behalf the EPA is implementing the federal plan. The EPA proposes to design this mechanism in a manner that would have no impact on the aggregate emission performance of sources required to meet rate-based emission standards during the compliance periods. The EPA requests comment on the structure of this mechanism, which could include adjusting the stringency of the emission standards during the compliance periods to account for the issuance of early action ERCs for MWh

[73] As discussed in section VIII.B.2 of the final EGs, in the case of a state that submits a final state plan including requirements for the state's participation in the CEIP, eligible RE projects may commence construction, and eligible EE projects may commence implementation, following the date of submission of a final state plan to the EPA. These projects must be implemented in or benefit the state that submitted the final state plan to the EPA, and may receive incentives for the zero-emitting MWh they generate or the end-use energy savings they achieve during 2020 and/or 2021.

generated or avoided in 2020 and/or 2021. For example, during the interim performance period, a number of ERCs could be retired in an amount equivalent to the number of early action ERCs that were awarded for MWh generated or avoided in 2020 and/or 2021. As another option, the EPA, or a state under the model trading rule, could adjust their targets to achieve the same stringency, taking into account the additional borrowed ERCs. The EPA requests comments on all potential methods to adjust state targets, including modeling-based approaches, and on what information the state must present to demonstrate that the new targets preserve the needed stringency. More generally, the EPA requests comments on these ideas, as well as on alternatives for maintaining the stringency of a rate-based plan implementing the CEIP so as to have no impact on the aggregate emission performance of sources required to meet rate-based emission standards during the compliance periods.

Second, the agency proposes to create an account of ''matching'' ERCs for each state participating in the CEIP—regardless of whether a state is implementing a state plan or the agency is implementing a federal plan on its behalf. This distribution would reflect each state's pro rata share—based on the amount of the reductions from 2012 levels the affected EGUs in the state are required to achieve relative to those in the other participating states—of a federal pool of additional ERCs, which would be limited to the equivalent of 300 million short tons of CO_2 emissions. Thus, states whose affected EGUs have greater reduction obligations will be eligible to secure a larger proportion of the federal pool upon demonstration of quantified and verified MWh of RE generation or demand side-EE savings from eligible projects realized in 2020 and/or 2021. The EPA intends that a portion of these matching ERCs would be reserved for eligible wind and solar projects, and a portion would be reserved for eligible EE projects implemented in low-income communities. The agency recognizes that there have been historical economic, logistical and information barriers to implementing EE programs in these communities, and therefore believes it is appropriate to reserve a portion of the federal pool to incentivize investment in these programs. The EPA requests comment on the size of reserve of matching ERCs for eligible low-income EE programs as well as for eligible wind and solar projects. The EPA is proposing that unused ERCs in either reserve would be redistributed among participating states. This redistribution could be executed according to the pro rata method discussed above. Alternatively, unused matching EE or RE ERCs could be swept back into a federal pool and distributed to project providers on a first-come, first served basis. EPA requests comment on these ideas as well as alternative proposals regarding the method for redistributing matching ERCs, as well as the appropriate timing for such a redistribution.

Following the effective date of a rate-based federal plan for a state, the agency will create an account of matching ERCs for the state that reflects the pro rata share of the 300 million short ton CO_2 emissions-equivalent matching poolthat the state is eligible to receive. Any matching ERCs that remain undistributed after September 6, 2018 will be distributed to those states with approved state plans that include requirements for CEIP participation, as well as to those states on whose behalf EPA is implementing a federal plan. These ERCs will be distributed according to the pro rata method outlined above. Unused matching ERCs that remain in the accounts of states participating in the CEIP on January 1, 2023, will be retired by the EPA.

7. Independent Verifiers

The EPA has determined in the final EGs that independent verification requirements are necessary to ensure the integrity of any rate-based emission trading program, given the types of eligible measures that may generate ERCs and the broad geographic locations in which those measures may occur. Inclusion of an independent verification component provides technical support for the EPA in the context of the proposed federal plan, and the states in the context of their plans, to ensure that eligibility applications and monitoring and verification reports are appropriately reviewed prior to issuance of ERCs. Inclusion of an independent verification component is also consistent with similar approaches required by state PUCs for the review of demand-side EE program results and GHG offset provisions included in state GHG emission budget trading programs.

The remainder of this section and the related language in the proposed model rule provide the proposed basis by which the EPA intends to evaluate the independence of the verifiers that it uses to provide verification reports pursuant to the federal plan. The qualifications described here and in the model rule would be presumptively approveable in the context of a state plan.

As a starting point, an independent verifier must have the necessary technical qualifications to provide verification services for the subject in question, as well as fulfill certain codes of conduct in providing verification services. Only verifiers approved or ''accredited'' by the EPA may provide verification services related to ERC issuance for the federal plan, in the same way that only verifiers approved by a state may be eligible to perform verification services pursuant to a state plan.[74]

In addition, verifiers must have sufficient knowledge of the rate-based emission trading program rules, technical expertise, and knowledge of auditing, accounting, and information management practices, in order to perform verifcation services related to the Clean Power Plan. Accredited verifiers must be independent. Accredited verifiers may not provide verification services for any eligible resource for which they have a financial, management, or other interest.[75] Such relationships constitute a conflict of interest (COI). COI situations may also arise as a result of personal relationships among individuals representing an ERC provider and an accredited verifier. A verification report would not be

[74] In this section, the term ''verifier'' is used interchangeably to refer to both a ''verification body'' (*i.e.,* a verification company or organization) and a ''verifier,'' which is an individual that is a principal or employee of a verification body.

[75] Accredited verification bodies and individual verifiers may not have any direct or indirect organizational or personal relationships with an ERC provider that would impact their impartiality in assessing the validity and accuracy of the information in an eligibility application or M&V report. In addition to this general requirement, the following specific requirements also apply. Accredited verifiers must have no direct or indirect financial interest in, or other financial relationships with, an ERC provider or any related program or project that seeks issuance of ERCs. Accredited verifiers must have no relationship with the implementer of a program or project that seeks the issuance of ERCs, or any related ERC provider, that would represent a COI. Accredited verifiers must have no role in the development and implementation of a program or project that seeks issuance of ERCs, beyond the provision of verification services. Accredited verifiers must not be compensated, directly or indirectly, in relation to the quantified and verified MWh in an M&V report or on the basis of program or project approval, ERC issuance, or the number of ERCs issued. Accredited verifiers may not hold ERCs, or other financial derivatives related to ERCs, or have a financial relationship with other parties that hold ERCs or other related financial derivatives. Verification reports must include an attestation by the accredited verifier that it assessed potential COI related to an ERC provider and adequately addressed any identified COI. The EPA requests comment the potential for payments to be channeled through the EPA as fees.

accepted as part of an eligibility application or M&V report where the accredited verification body or any individual verifier has a COI. Accredited verification bodies must have management protocols in place to identify and remedy any COI prior to provision of verification services. The proposed federal plan and model rule provide that failure of an accredited verifier to identify and adequately address any COI prior to provision of verification services is grounds for revocation of accreditation. The EPA would perform periodic reviews of accredited verifiers, to ensure that verifiers are maintaining necessary technical and professional qualifications and are meeting program requirements for provision of verification services. The EPA may recognize, in part, accreditation by an outside organization where such outside accreditation demonstrates that federal plan requirements are met.[76] The EPA requests comment on the proposed necessary requirements for an independent verifier to perform verification services in connection with the federal plan, including those requirements specifically detailed in this section of the preamble and the related language in the proposed model rule, and including whether there are any requirements that are not included in this proposal that should be included in the final rule. We further request comment on the level of detail that we should include in the final model rule regarding all requirements for indepenent verifiers, and all aspects of verification.

8. Evaluation, Measurement, and Verification Plans, Monitoring and Verification Reports, and Verification Reports

This section identifies and discusses the EM&V approaches used to quantify and verify MWh from RE, demand-side EE, and other eligible measures used to generate ERCs or otherwise adjust an emission rate.[77]

Only a subset of the potentially creditable ERC resources discussed in this section are actually being proposed as part of the federal plan. The remainder, and their associated requirements, are provided as part of the proposed model trading rule. Thus, all provisions of this subsection relating to such resources are presented only for the purpose of comment in the context of the federal plan, but are actually proposed for inclusion in the model trading rule. The ERC resources proposed in the federal plan must meet the following criteria: (1) They are in the following categories of measures: On-shore wind, solar, geothermal power, hydropower, or new nuclear units and capacity uprates at existing nuclear units; and (2) they can provide quantified generation data from a revenue quality meter. The language pertaining to all other measures (*e.g.,* demand-side EE) is proposed only for the model rule. While they are currently being proposed as part of the model rule and not the federal plan, the EPA requests comment on the inclusion of other RE measures, demand-side EE measures, and any other measures that may be eligible under the final guidelines as eligible measures under the federal plan. For stakeholders that are submitting comments on the inclusion of such additional measures, the EPA requests comment on how the EPA could implement across applicable jurisdictions a rigorous, straightforward, and widely demonstrated set of EM&V methods, procedures, and approaches that could be implemented in the time frame allowed by the federal plan and that also meet the requirements outlined in the final guidelines. To the extent they are proposed for inclusion in the model trading rule, we also invite comment on these requirements in the context of state implementation as part of a state plan. Thus, commenters on this aspect of the proposal should consider whether and how these provisions could be implemented at the state level. Comments that suggest an approach not authorized by the EGs will likely be considered outside the scope of this proposed rule.

Additionally, with respect to EM&V, the EPA describes certain established industry best-practice methods, procedures, and approaches that would be presumptively approvable if included in state plans. States wishing to adopt the model rule must submit these methods, procedures, and approaches as specified, or may submit alternative EM&V that is functionally equivalent to the industry best-practices described as presumptively approvable.[78]

As discussed in section IV.C.3 of this preamble, quantified and verified MWh of RE generation and other means of generating ERCs may be used to adjust a CO_2 emission rate when demonstrating compliance with the EGs. Providers other than affected EGUs who seek to earn ERCs must develop EM&V plans outlining how they will quantify and verify the resulting MWh from their efforts. These providers must then submit these EM&V plans as part of their application to the Administrator for project approval.[79]

a. *Overall Approach and Measure-Specific Requirements.* The proposed Clean Power Plan stated that the EPA would establish EM&V requirements and procedures to help states, sources, and resource providers quantify and verify MWh savings and generation resulting from zero-emitting RE and demand-side EE efforts. This action proposes those requirements that the EPA committed to establish. The Clean Power Plan proposal and associated ''State Plans Considerations'' TSD[80] suggested that such EM&V requirements would leverage existing industry practices, protocols, and tracking mechanisms currently utilized by the majority of states implementing RE and demand-side EE. The EPA further noted that many state regulatory bodies and other entities already have significant EM&V infrastructure in place and have been applying, refining, and enhancing their evaluation and quality assurance approaches for over 30 years, particularly with regard to the quantification and verification of energy savings resulting from utility-administered EE programs. The EPA also observed that the majority of RE generation is typically quantified and verified using readily available, reliable, and transparent methods such as direct metering of MWh. The EPA is proposing EM&V methods, procedures, and approaches, described herein, that are intended to be consistent with and leverage prevailing industry best-practices.

In addition, the EPA's proposed EM&V methods, procedures, and

[76] An example is American National Standards Institute (ANSI) accreditation under ISO 14065:2013 for GHG validation and verification bodies. More information is available at *https://www.ansica.org/wwwversion2/outside/GHGgeneral.asp.*

[77] EM&V is defined here as the set of procedures, methods, and analytic approaches used to quantify the MWh from RE, demand-side EE, and other eligible measures to ensure that the resulting savings and generation are quantifiable and verifiable. In this proposal, we are proposing EM&V for the eligible RE, and we request comment on EM&V for demand-side EE and any other measures that could be eligible.

[78] The EPA recognizes that EM&V is routinely evolving to reflect changes in markets, technologies and data availability, and expects to update its EM&V guidance over time. Therefore the agency expects that alternative quantification approaches will emerge that can be approved for use, provided that such approaches are functionally equivalent to the provisions for EM&V outlined in this section.

[79] A full discussion of applicable requirements for the establishment and functioning of the rate-based trading system is provided above, in section IV.D of this preamble.

[80] See discussion beginning on p. 34 of the State Plan Considerations TSD for the Clean Power Plan Proposed Rule: *http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule-state-plan-considerations.*

approaches reflect several overarching objectives and principles offered by states, private organizations, and the public during the comment period of the Clean Power Plan EGs. One of these is the importance of balancing the accuracy and reliability of results with the associated costs of EM&V. Another objective for the EPA's proposed EM&V is to avoid excessive interference with existing practices that are already robust, transparent and effective.

Submittals. Applicable submittals under a rate-based emission trading program include eligibility applications (including EM&V plans), monitoring and verification reports, and verification reports. These submittals are described in section VIII.K.3.b of the final EGs preamble and in this model rule and federal plan. At the initiation of a program or project, ERC providers develop and submit to the state or the EPA, respectively, an EM&V plan that documents how requirements for quantification and verification will be addressed as EM&V is performed over the program or project period. After implementation has occurred, the ERC provider must submit periodic M&V reports to document and describe how each of the requirements were applied. These reports must also specify the resulting MWh savings or generation values, as determined on a retrospective (ex-post) or real-time basis. MWh values may not be determined using projections or other ex-ante quantification approaches.

Each EM&V plan submitted in support of an eligibility application must identify the eligible resource covered by the plan, and provide specific EM&V criteria that specify the manner in which the energy generated or saved by the eligible resource will be quantified, monitored and verified. The manner of quantification, monitoring and verification must meet the criteria outlined below and included in the proposed model rule, as applicable to the specific eligible resource. We request broad comment on each criteria specified below and in the proposed model rule, for each eligible resource. Specifically, we seek comment on the substantive content of the criteria, and we seek comment on the level of detail provided and whether more or less detail (and what detail) should be included in the final model rule, and whether the criteria should differ for each eligible resource.

Each M&V report submitted in support of the issuance of ERCs to a specific eligible resource must include specific criteria described here and in the proposed model rule. For the first M&V report submitted, a key component is documentation that the electricity-generating resources or electricity-saving measures were installed or implemented consistent with the description in the approved eligibility application. Each following M&V report must then identify the time period covered by the M&V report, describe how the methods specified in the EM&V plan were applied during the reporting period, and document the quantity (in MWh) of energy generation and/or electricity savings quantified and verified for the period covered by the M&V report. Any change in the energy generation or savings capability of the eligible resource during the period covered by the M&V report must also be included in the M&V report, along with the date on which the change occurred, and information sufficient to demonstrate whether the eligible resource continued to meet all eligibility requirements during the period covered by the M&V report. Any change should also be specified in the report. The EPA requests broad comment on each of these criteria, as described here and in the proposed model rule. Specifically, we seek comment on the substantive content of the criteria, and we seek comment on the level of detail provided and whether more or less detail (and what detail) should be included in the final model rule, and whether the criteria should differ for each eligible resource.

Each verification report submitted by an independent verifier in support of the issuance of ERCs to a specific eligible resource must address the criteria described here and in the proposed rule text. Each verification report must set forth the findings of the verifier, based on an assessment of all relevant requirements, information and data, including an assessment of any material misstatements or data discrepancies. Any verification report included as part of an eligibility application must further describe the review conducted by the verifier and verify the following: The eligibility of the resource to be issued ERCs; that the eligible resource exists and has been, or will be, generating energy or saving electricity in the manner required; that the EM&V plan meets its requirements; and any other information required or that the verifier finds, in its professional opinion, is necessary to assess the accuracy of the subject of the verification report. Each verification report included as part of a M&V report must also describe the review conducted by the verifier and verify the following: The adequacy and validity of the information and data submitted to quantify eligible MWh of electric generation or electricity savings during the period covered by the report, as well as all supporting information and data identified in the EM&V plan and M&V report; evaluate whether all generation or savings data are within a technically feasible range for that specific eligible resource (determined through a quality assurance and quality control check of the data); that the M&V report meets its requirements; and any other information required or that the verifier finds, in its professional opinion, is necessary to assess the accuracy of the subject of the verification report. The EPA requests broad comment on each of these criteria, as described here and in the proposed model rule. Specifically, we seek comment on the substantive content of the criteria, and we seek comment on the level of detail provided and whether more or less detail (and what detail) should be included in the final model rule, and whether the criteria should differ for each eligible resource.

For demand-side EE, all EM&V plans that are developed for purposes of adjusting an emission rate under this proposed rule are intended to leverage and closely resemble the plans already in routine use for a wide range of publicly or rate-payer funded EE programs and energy service company (ESCO) projects. For RE, EM&V plans similarly leverage resources and approaches to MWh tracking for RE that are broadly applied in the state and regions. The existing reports and documentation from existing tracking systems may serve as the substantive basis for a monitoring and verification report for RE.

b. *Renewable Energy EM&V Requirements.* This section describes the EM&V requirements associated with quantifying electricity generation from eligible RE and nuclear energy, and for documenting these requirements in EM&V plans and reports. Consistent with prevailing views expressed in public comments, the EPA's requirements presume that the quantification of RE generation can leverage the infrastructure and documentation associated with the establishment of renewable energy certificates (RECs) and registration of such certificates in REC registries. These registries typically include well-established safeguards, documentation requirements, and procedures for registry operations intended to support the demonstration of compliance with state RPS policies. A key element of RPS compliance is that each RE generating unit must be uniquely identified and recorded in a registry to avoid the double counting of RECs.

The primary metric for all RE is electricity generation, in units of MWh. Measured output must be derived either from: (1) A revenue quality meter that meets the applicable ANSI C–12 standard or equivalent, which is the typical requirement for settlements with RTO and other control-area operators; or (2) For customer-sited generators that are interconnected behind the customer meter, measurement at the AC output of an inverter, adjusted to reflect the energy delivered into either the transmission or distribution grid at the generator bus bar. Further, a RE generating facility of 10 Kilowatt capacity or less may estimate the facility's output if the state where it is located explicitly allows estimates to be used and provides rules for when it will be allowed. In the latter case, calculations of system output must be based on the RE unit's capacity, estimated capacity factors, and an assessment of the local conditions that affect generation levels. All such input parameters and assumptions must be clearly described and documented. For RE units that are managed by regional transmission operators or other control area operators, metered generation data should be electronically collected by the control area's energy management system, verified through an energy accounting or settlements process, and reported by the control area operator to the REC registry at least monthly. The EPA requests comment on this proposed requirement for quantifying RE generation for the purpose of ERC issuance.

For RE units that do not go through a control area settlements process, metered data may be read and transmitted to the ERC registry by an independent third party, or may be self-reported. Third-party and self-reported generation data must be reported on an annual basis. All such data must be verified for reasonableness by the agency, the state, or the REC registry.

For reporting purposes, RE generation may be aggregated from multiple generators into a single MWh value for the group, provided the following requirements are met: Each RE unit is uniquely identified in the federal tracking system, the nameplate capacity of each RE unit is less than 150 Kilowatt, the aggregated RE units collectively have nameplate generating capacities less than 1.0 MW, the units aggregated are located in the same state, the RE units being aggregated utilize the same technology/fuel type, and the RE unit's generation data are based on the same metering or the same generation estimating software or algorithms. The EPA requests comment on how existing reporting systems can play a role in meeting EM&V requirements under the federal plan and model rule, particularly, in assuring that each MWh of RE generation is uniquely identified and recorded to avoid double counting.

An additional consideration regarding distributed RE units that directly serve on-site end-use electricity loads is that avoided transmission and distribution (T&D) system losses can be quantified, as is commonly practiced with demand-side EE. If such T&D losses are quantified, the requirements for demand-side EE would be applicable.

The EPA requests comment on all metering, measurement, verification, and other requirements proposed in this subsection, including the appropriateness of their use for each type of RE resource (including the relevant size and distribution of such resource) that qualifies for issuance of ERCs for use for compliance.

For RE resources with a nameplate capacity of 10 Kilowatt or more and for RE resources with a nameplate capacity of less than 10 Kilowatt for which metered data are available, we request comment on the appropriateness of the requirement to use a revenue quality meter for monitoring generation, and we request comment on the definition of revenue quality meter. We request comment on the appropriateness of other types of meters for monitoring generation. We request comment on whether 10 Kilowatt is the appropriate threshold, under which an eligible resource can be issued ERCs for generation based on data other than metered generation, and if not, what would be the appropriate threshold.

For RE resources of all sizes and means of monitoring, we request comment on the appropriate requirements for allowing generation data to be aggregated, including comment on the provisions in the proposed model rule and any alternatives to them. We request comment on whether all of the generating units have the same essential generation characteristics, in order for their data to be aggregated, and if so, what is the appropriate definition of ''essential generation characteristics'' (*e.g.,* are essential generating characteristics determined on a resource by resource basis, or can generation from a group of wind turbines be aggregated with generation from a group of solar panels?) We seek comment on the appropriate thresholds for the aggregated of individual units (*e.g.,* nameplate capacity of less than 150 Kilowatt per unit and the units collectively do not exceed a total nameplate capacity of 1 MW when aggregated, as in the proposed model rule).

For non-metered units of less than 10 Kilowatt, we request comment on whether the final model rule should specify the specific estimating software or algorithms by which generation data should be measured, and if so, we request broad comment on the appropriate estimating software or algorithms and the appropriate characteristics for such estimating software or algorithms.

We request comment on any other requirements that should be included in the final model rule regarding EM&V of RE resources.

For all energy generating resources (such as RE, but also including applicable resources requiring EM&V described below), we request comment on the appropriate place of measurement of the generation, including comment on whether measurement should be at the bus bar or at a different location (or in the case of meters on units of less than 10 Kilowatt, at the AC output of the inverter or elsewhere), whether measurement should be before or after parasitic load (and how to separate out parasitic load). In addition, for all energy generating resources, we request comment on whether generation data should go through a control area settlement process prior to issuance of ERCs, and if so, what level of specificity with respect to that process we should include in the final model rule. If not, or if the unit does not go through a control area settlement process, we request comment on how the data collection should be specified in the final model rule. Finally, we request comment on the frequency with which data should be collected, for all energy generating resources, of all sizes.

c. *Nuclear EM&V Requirements.* The EM&V requirements associated with quantifying electricity generation from eligible nuclear energy resources, and for documenting these requirements in EM&V plans and reports are the same as the requirements for RE discussed in the preceding subsection.

The EPA requests comment on all metering, measurement, verification, and other requirements in this subsection, including the appropriateness of their use for each type of nuclear energy resource (including the relevant size and distribution of such resource) that qualifies for issuance of ERCs for use in Clean Power Plan compliance. We request comment on whether nuclear energy resources should be subject to the same EM&V requirements as RE resources, and if not, we request comment on to which EM&V requirements nuclear energy resources should be subject.

d. *Non-Affected Combined Heat and Power EM&V Requirements.* In additon to the CHP specific EM&V requirements discussed below and in the associated provisions in the model rule, all CHP must follow the requirements for RE discussed in the preceding subsection, including metering requirements, special treatment for units of less than 10 Kilowatt, and how to account for T&D losses.

In order to determine the incremental CO_2 emission rate, a CHP unit would monitor CO_2 emissions and energy output.[81] The monitoring requirements are standard methods currently in use and the requirements would depend on the size of the CHP units and the fuel used in the unit.

Non-affected CHP facilities [82] with electric generating capacity greater than 25 MW would follow the same monitoring and reporting protocols for CO_2 emissions and energy output as are required for affected EGU CHP units. These requirements are discussed in section IV.D.13 of this preamble. For non-affected CHP facilities with electric generating capacity less than or equal to 25 MW, which use only natural gas and/or distillate fuel oil, the low mass emission unit CO_2 emission monitoring and reporting methodology outlined in 40 CFR part 75 is acceptable.

The EPA requests comment on all metering, measurement, verification, and other requirements included in this subsection with respect to CHP, including the appropriateness of their use for CHP (including with respect to the size of the CHP resource). We request comment on whether a CHP unit should be subject to the same EM&V requirements as RE resources, and we request comment on any additional EM&V requirements to which CHP units should be subject. Specifically, we request comment on specifying in the final model rule that if a CHP unit has an electric generating capacity greater than 25 MW, its EM&V plan must specify that it will meet the requirements that apply to an affected EGU under 40 CFR 62.16540. We also request comment on specifying in the final model rule that if a CHP unit has an electric generating capacity less than or equal to 25 MW, the EM&V plan must specify that it will meet the low mass emission unit CO_2 emission monitoring and reporting methodology in 40 CFR part 75. We request comment on any alternatives to these measurement methodologies that should be specified in the final model rule. We request comment on any other requirements that should be included in the final model rule regarding EM&V of CHP.

e. *Biomass EM&V Requirements.* A state plan that is adopting the rate-based model rule must propose EM&V requirements for monitoring and reporting biogenic CO_2 emissions from the use of qualified biomass at RE facilities that are eligible for adjusting a CO_2 emission rate. If a state proposes to use the monitoring and reporting requirements for biogenic CO_2 emissions in 40 CFR part 98 (40 CFR 98.3(c), 98.36(b)–(d), 98.43(b), and 98.46) in its plan submission, those requirements are presumptively approvable. An EM&V plan that addresses biomass RE must follow the requirements for monitoring and reporting biogenic CO_2 emissions from the facility that were approved by the EPA in connection with the specific state plan.

The EPA requests comment on all metering, measurement, verification, and other requirements included in this subsection with respect to biomass, including the appropriateness of their use for qualified biomass. We request broad comment on the types of qualified biomass feedstocks that should be specified in the final model rule, if any. We request comment on the methods that we should specify in the final model rule for the measurement of the associated biogenic CO_2 for such feedstocks, as well as what other requirements we should specify in the final model rule related to qualfied biomass. We request comment on any other requirements that should be included in the final model rule regarding EM&V for qualified biomass. Detailed discussion on the role of qualified biomass feedstocks can be found in section IV.C.3 of this preamble.

f. *Waste-to-Energy EM&V Requirements.* A state plan that is adopting the rate-based model rule must propose EM&V requirements for monitoring and reporting biogenic CO_2 emissions from waste-to-energy facilities that are eligible for adjusting a CO_2 emission rate. If a state proposes to include the monitoring and reporting requirements for biogenic CO_2 emissions in 40 CFR part 98 (40 CFR 98.3(c), 98.36(b)–(d), 98.43(b), and 98.46) in its plan submission, those requirements are presumptively approvable. The EPA may approve other requirements of similar rigor, at its discretion. An EM&V plan that addresses the biogenic CO_2 emissions from a waste-to-energy facility must follow the requirements for monitoring and reporting biogenic CO_2 emissions from the facility that were approved by the EPA in connection with the specific state plan.

As discussed in the final EGs (see section VIII.K.1 of the final EGs), only the portion of electric generation at a waste-to-energy facility that is due to the biogenic content of the MSW may be used to generate ERCs or counted by a state towards its achievement of its obligations pursuant to this regulation.

The EPA requests comment on all metering, measurement, verification, and other requirements included in this subsection with respect to waste-to-energy, including the appropriateness of their use for waste-to-energy. We request comment on whether a waste-to-energy resource should be subject to the same EM&V as RE resources, and we request comment on any additional EM&V requirements to which waste-to-energy resources should be subject, including comment on any specific methods for determining the specific portion of the total net energy output from the resource that is related to the biogenic portion of the waste that the EPA should include in the final model rule.

g. *Demand-Side Energy Efficiency EM&V Provisions.* This subsection proposes EM&V provisions that will be presumptively approvable if included in state regulations governing how EE is to be quantified by EE providers and verified by independent entities acting on behalf of the state. As noted above these proposed provisions apply to all demand-side EE used to adjust an emission rate if a state adopts the model rule. The EPA is soliciting comment on the incorporation of EE for the federal plan and by extension the EM&V associated with it.

For all demand-side EE used to generate ERCs, the EPA is proposing that the metric is MWh of electricity savings, which must be quantified on an ex-post or real-time basis and defined as a reduction in facility- or premises-level electricity consumption due to an EE program, project, or measure.

(1) Common Practice Baseline

Based on public input and assessments of industry best-practice protocols and procedures, the EPA is proposing that it is presumptively approvable to quantify EE savings as the difference between actual metered electricity usage after an EE program, project, or measure is implemented, and a ''common practice baseline'' (CPB). A

[81] When a CHP unit uses biomass fuel, it must report both total CO_2 emissions and biogenic CO_2 emissions. Proposed requirements for reporting biogenic CO_2 emissions are discussed below in the subsection titled Biomass *EM&V requirements.*

[82] A CHP facility may consist of one or more electric generators.

CPB is the equipment that would most frequently be installed at the time an existing piece of equipment fails or is replaced at the end of its effective useful life—or that a typical consumer or building owner would have continued using for the remainder of the equipment's effective useful life—in a given circumstance (*i.e.,* a given building type, EE program type or delivery mechanism, and geographic region) at the time of EE implementation. It defines what would commonly have happened in the absence of the EE program, project, or measure.

The applicable CPB depends on a number of factors, such as characteristics of the EE program, project, or measure, the mechanism by which electricity customers are engaged, local consumer and market characteristics, and the applicable building energy codes and product standards (C&S), including the C&S compliance rate. Examples of appropriate CPBs to apply in specific circumstances, which may be presumptively approvable, can be found in the EPA's EM&V guidance. EE providers must document the selected CPB in their EM&V plans, along with clear documentation and discussion of the rationale, applicability, and relevant data sources, protocols, and other supporting information. Monitoring and verification reports must refer to the EM&V plan and confirm that the CPB was appropriately applied.

(2) Methods Used To Quantify Savings From Energy Efficiency Programs and Projects

This section proposes criteria that are presumptively approvable for the general types of EM&V methods that EE providers may use to quantify the MWh savings from demand-side EE programs, projects, and measures. During the Clean Power Plan EG's public comment period, the EPA received input indicating that state PUCs typically allow utilities and other EE providers to use a range of EM&V methods that reflect applicable circumstances and on-the-ground conditions (versus mandating which methods must be used in a particular situation). Consistent with this approach, the EPA is proposing to offer flexibility for EE providers to select from three broad categories of EM&V methods to determine savings.

These categories include project-based M&V, deemed savings, and comparison group approaches such as randomized control trials (RCT). Regardless of the approach selected, the EPA is proposing that annual savings values must be quantified using these EM&V methods at specified time intervals (in years) on a recurring basis over the effective useful life of the EE project or measure in order to ensure accurate and reliable savings values. To be presumptivey approable, the EPA is proposing that EE providers must apply the above methods at a minimum of 4-year intervals for building energy codes and product standards; every 1, 2, or 3 years for publicly- or utility-administered EE programs, depending on the program type, magnitude of savings, and experience with the program; and annually for large individual commercial and industrial projects, unless the EE provider can credibly demonstrate why this is not possible and how the accuracy and reliability of savings values will be maintained. The EPA is further proposing that, to be presumptively approvable, the selected method, associated assumptions, and data sources must be identified and described in EM&V plans.

For comparison group approaches, the EPA is propsing that states and EE providers can refer to the EPA's draft EM&V guidance for a discussion of industry best-practice protocols and guidelines. Where feasible, the EPA is proposing to encourage the use of RCT methods, which determine savings on the basis of energy consumption differences between a treatment group and a comparison group, and therefore increase the reliability of results.

As noted above, an alternative to comparison group methods is the use of deemed savings values, which establish pre-determined annual electricity savings values for specific EE measures. The EPA is proposing that the use of deemed savings values would be presumptively approvable if those values (a) are documented in a publicly available database (also known as a Technical Reference Manual (TRM)) that is accessible on a public Web site, or is otherwise readily accessible; (b) specify the conditions for which each deemed value can be applied, including but not limited to climate zone, building type, and EE implementation mechanism; and (c) are updated at a minimum of every 3 years to reflect the per-measure MWh savings documented in ex-post EM&V studies that apply M&V or comparison group methods.

For M&V methods to be presumptively approvable, the EPA is proposing is that industry best-practice protocols and/or guidelines must be followed. Examples of acceptable best-practice protocols and guidelines are provided in the EPA's EM&V guidance. EE providers can consult the EM&V guidance to assess the applicability of these technical resources to the EE programs and projects generating savings, and must document how one or more best-practice protocols or guidelines will be appropriately applied in EM&V plans (along with clear documentation and discussion of the rationale, applicability, and relevant data sources, and other supporting information). The EPA is also proposing that monitoring and verification reports must refer to the EM&V plan and confirm that the relevant M&V protocol or guideline was properly applied.

(3) Quantifying Savings

Regardless of the approach used to quantify and verify MWh savings, the EPA is proposing that EM&V plans must describe how they will address the following provisions:

- How major changes in independent variable conditions (weather, occupancy, production rates, etc.) that affect energy consumption and savings estimates will be accounted for. The EPA is proposing that the effects of these changes must be calculated using industry best-practices such as real-time conditions or normalized conditions that are reasonably expected to occur throughout the lifetime of the EE project or measure.
- How the initial installation of EE will be verified for EE program categories that involve the installation of identifiable measures (*e.g.,* most utility consumer-funded EE programs and project-based EE are evaluated site-by-site). The EPA is proposing that verification is required within the first year of program implementation and that all verification activities must be performed using industry best-practice techniques (*e.g.,* phone or mail surveys, document review, site inspections, spot or short-term metering). For projects implemented as part of a larger program, the EPA is proposing that verification can be performed using a sample of projects to represent the full program population.
- How avoided T&D system losses [83] will be quantified and applied to EE savings determined at the customer facility or premises. The EPA is proposing that demand-side EE programs (other than T&D efficiency measures such as *conservation voltage regulation or reduction* (CVR) and volt/VAR optimization [84]) may adjust

[83] T&D losses are defined as the difference between the quantified EGU generation required to serve a customer's load (measured at the EGU bus bar) and the customer's actual electricity consumption (measured at the customer meter).

[84] More information about these technologies is in section VIII.F.1 of the final EGs.

reported savings by using a T&D adder. If such an adder is applied, the presumptively approvable approach is to use the smaller of 6 percent or the calculated statewide annual average T&D loss rate (expressed as a percentage) calculated using the most recent data published by the U.S. EIA State Electricity Profile.[85]

• How the duration of EE program or project electricity savings will be determined. This must be determined using industry best-practice protocols and procedures involving annual verification assessments, industry-standard persistence studies, deemed estimates of effective useful life (EUL), or a combination of all three.

• How the accuracy and reliability of quantifying MWh savings values will be assessed, and the rigor[86] of the methods used to control the types of bias or error inherent to the applied EM&V methods. Sampling of populations is appropriate, provided that the quantified MWh derived from sampling have at least 90 percent confidence intervals whose end points are no more than +/−10 percent of the estimate.

• How double counting will be avoided through the use of tracking and accounting procedures to ensure that the same MWh of electricity savings is not claimed more than one time (for example, two EGUs claiming savings from the same lighting retrofit). The types of double counting that may arise are discussed in the EPA's draft EM&V guidance.

(4) Use of Energy Efficiency EM&V Protocols

In the Clean Power Plan EG's public comments, the EPA heard that EM&V protocols for demand-side EE are currently in wide use, and that they should be continued and encouraged. The agency agrees with this observation and is therefore proposing the application of industry best-practice protocols and procedures for demand-side EE. In particular, the EPA is proposing that, to be presumptively approvable, EM&V plans must specify the use of best-practice protocols and procedures, and must also include a clear description and documentation of how the relevant protocols and procedures will be applied. EM&V reports must include documentation of how such protocols and procedures were actually applied. EE providers can refer to the EPA's EM&V guidance document for information about protocols that are considered ''industry best-practice protocols and procedures.''

(5) Eligible Demand-Side Energy Efficiency (DS–EE) Programs and Projects

There has been stakeholder interest expressed through the Clean Power Plan EGs rulemaking process in allowing states to issue ERCs for quantified and verified MWh savings from DS–EE under state plans. Consistent with these perspectives, the EPA is proposing that any demand-side EE program, project, or measure that results in MWh savings may be potentially eligible to generate ERCs, including under this proposed model trading rule, provided that they meet the presumptively approvable provisions for eligibility described in section IV.C.3 of this preamble, and that supporting EM&V is rigorous, transparent, credible, complete and fulfills the requirements provided in the EGs and the state plan. Examples of potentially eligible demand-side EE program and project types include:

• Publicly or utility-administered EE programs, including those implemented in low-income residences and facilities.

• Project-based EE evaluated site-by-site, for example those implemented by ESCOs at commercial buildings and industrial facilities.

• State and local government building energy code and compliance programs.

• State and local government incremental product energy standards.

The EPA's EM&V guidance contains supplemental information about applicable best-practice protocols, methods, and other key considerations for quantifying and verifying savings from the above-listed EE activities in an accurate and reliable manner. The agency also recognizes that the programs and policies listed above will evolve and change over the rule period, as new technologies emerge and efficiency improves. The agency also expects that new EE program types will emerge and expand throughout the rule period, and that MWh savings resulting from any such programs can similarly be considered if they meet the requirements of the EGs.

(6) Requests for Comment on Energy Efficiency EM&V

We request broad comment on each EE EM&V criterion described herein and in the proposed rule text, for each type of EE activity, project, program, or measure. Specifically, we seek comment on the substantive content of the criteria, and we seek comment on the level of detail provided regarding these criteria and whether more or less detail (and what detail) should be included in the final model rule. In addition, we seek comment on whether some of the EE EM&V criteria (and if so, which criteria) included in the draft guidance document released simultaneously with this proposed rulemaking should instead be included in the final model rule, instead of in guidance. Similarly, we seek comment on whether some of the EE EM&V criteria (and if so, which criteria) included in the proposed model rule should instead be addressed in the final EM&V guidance. More generally, we seek comment on what EE criteria the EPA should described in guidance versus what criteria the EPA should specify in the final model rule, whether or not those criteria are already included in the draft guidance or proposed model rule.

We request broad comment on the appropriate EE EM&V criteria for quantifying the electricity savings from every type of EE program, project, or measure. We request broad comment on what constitute EE best-practice protocols and procedures for every type of EE program, project, or measure.

We request broad comment on whether, when, and how common practice baselines should and should not be used in calculating electricity savings from EE activities, projects, programs, and measures, including comment on which common practice baselines should be used in which circumstances. We also request comment on whether some alternative metric should be used in lieu of the common practice baseline and, if so, what that metric should be.

We request broad comment on the appropriateness of quantifying electricity savings by applying one or more of the following methods and comment on all aspects of each method: Project-based measurement and verification (PB–MV), comparison group approaches, or deemed savings. We take further comment on circumstances in which it is appropriate (or inappropriate) to use each of these methods, including when it is appropriate to use RCT and quasi-experimental methods, and the circumstances in which they can be encouraged and applied in practice (*e.g.,* when a suitable control or comparison group can be identified and applied in a cost-effective manner). In addition, we request comment on whether the general suitability and applicaton of quantification methods, such as RCT,

[85] Estimated losses in MWh, total electric supply, and direct electricity use values are available in the U.S. EIA's State Electricity Profiles. *See* Table 10 on Supply and Disposition of Electricity. Direct electricity use refers to the electricity generated at facilities that is not put onto the electricity grid, and therefore does not contribute to T&D losses.

[86] Rigor refers to the level of effort expended to minimize uncertainty from factors such as sampling error and bias. The higher the level of rigor, the more confident one is that the results of the EM&V activities are both accurate and precise.

quasi-experimental techniques or other comparison group approaches when they are available at reasonable cost for purposes of quantifying MWh savings for particular EE programs, projects, or measures.

If deemed savings are to be used in quantifying electricity savings from an EE program, project, or measure, we request comment on the appropriate characteristics and presumptively approvable provisions for their use in generating qualifying ERCs, including the basis and frequency for their determination, and the appropriateness of their application to particular EE programs, projects or measures in particular states or regions. We further request comment on the presumptively approvable provision for public access and input to the development of the technical reference manuals (TRMs) used to house the applicable deemed savings values.

We request comment on the minimum and maximum intervals (in years) over which electricity savings must be quantified, including those time intervals specified in the proposed model rule, and we request comment on any factors that must be taken into consideration when determining the appropriate time interval for specific EE programs, projects, or measures.

Because many states have different EE programs in place today, and we would expect them to leverage these programs if they incorporated EE into a rate-based trading scheme with ERCs, it is theoretically possible that an ERC could be issued in one state that would not have been issued in another, even if both states have rate-based programs in place that meet all of the EGs. The EPA requests comment on what criteria it should include in the final model rule, and what level of details with respect to those criteria that it should include, in order to ensure that an ERC issued for an EE program, project, or measure in one state reflects the same MWh of energy or electricity saved in another state. We further request comment on whether there are provisions that the EPA should include in the final model rule that would prevent an entity seeking to be issued an ERC (whether from EE or energy generation) from forum shopping, in an effort to find a state with standards for ERC issuance that it deems more lenient or less burdensome than those in another state.

We request comment on how to appropriately consider factors that affect energy savings in the quantification and verification process, including those identified in the proposed model rule, and we request comment on whether these factors should be addressed in every plan or just certain types of plans. Such factors may include the effect of changes in independent factors, effective useful life (and its basis), and interactive effects of EE programs, projects, and measures.

We request comment on the circumstances and frequency in which savings verification must occur to ensure that EE measures have been installed, are functioning, and have the potential to save energy.

We request comment on the appropriate steps for avoiding double counting, and how such steps should be documented in an EM&V plan. In particular, we request comment on the circumstances and conditions in which double counting is most likely to occur (including those identified in this section), and the presumptively approvable provisions that must be adopted in state plans for avoiding and mitigating double counting.

We request comment on the appropriate means by which an EM&V plan can ensure the accuracy and reliability of electricity savings estimates, including the necessary rigor of the methods selected to evaluate the electricity savings, the methods used to control all relevant types of bias and to minimize the potential for systematic and random error, and the potential effects of such bias and error. We further request comment on the presumptively approvable provision that samples taken to quantify EE program savings must achieve 90/10 confidence and precision.

We request comment on the presumptively approvable approach to quantifying the electricity savings that result from avoiding a transmission and distribution system loss, including the provisions in the proposed model rule, which specify that each EM&V plan must quantify the transmission and distribution loss based on the lesser of 6 percent of the site-level electricity consumption measured at the end use meter or the statewide annual average transmission and distribution loss rate (expressed as a percentage) from the most recent year that is published in the U.S. EIA State Electricity Profile. We request comment on the appropriateness of including a restriction in the final model rule that no other transmission and distribution loss factors may be used in calculating the electricity savings.

We request comment on any additional criteria that we should include in the final model rule regarding EE EM&V.

h. *Skill Certification Standards.* Using a skilled workforce to implement demand-side EE and RE projects and other measures intended to reduce CO_2 emissions, and to evaluate, measure and verify the savings associated with EE projects or the additional generation from performance improvements at existing EGU's are both important. Several commenters on the EGs pointed out that skill certification standards can help to assure quality and credibility of demand-side EE, RE, and other carbon emission reduction projects. The EPA also recognizes that a skilled workforce performing the EM&V is important to substantiate the authenticity of emission reductions.

The EPA agrees that in conjunction with other EM&V measures discussed in this section, and in the context of the model trading rules although this is not an aspect needed for presumptive approvability, states are encouraged to include in their plan a description of how states will ensure that workers installing demand side EE and RE projects, or other measures intended to reduce CO_2 emissions, as well as workers who perform the EM&V of demand side EE and existing EGU performance will be certified by a third party entity that:

- Develops a training or competency based program aligned with a job task analysis and/or certification scheme;
- Engages with subject matter experts in the development of the job task analysis and/or certification schemes that represent appropriate qualifications, categories of the jobs, and levels of experience;
- Has clearly documented the process used to develop the job task analysis and/or certification schemes, covering such elements as the job description, knowledge, skills, and abilities;
- Has pursued third-party accreditation aligned with consensus-based standards, for example ISO/IEC 17024 or IREC 14732.

Examples of such entities include: Parties aligned with the DOE's Better Building Workforce Guidelines and validated by a third party accrediting body recognized by DOE; or parties aligned with an apprenticeship program that is registered with the federal DOL, Office of Apprenticeship; or parties aligned with a state apprenticeship program approved by the DOL, or by another skill certification validated by a third party accrediting body. Entities such as these can help to substantiate the authenticity of emission reductions due to demand-side EE and RE and other carbon emission reduction measures.

9. ERC Transfers and Trading

All affected EGUs that may be subject to this proposed federal plan would be required to be a part of the ATCS that the EPA runs, although the affected EGUs that are regulated under the rate-based federal plan would use ERCs as a compliance instrument, not allowances. To register to participate in the ATCS an affected EGU must submit designated representative information. More information on the designated representatives is described above in section IV.D.1 of this preamble. Non-EGUs who wish to participate (*e.g.,* RE sources) may submit registration criteria to participate in the ATCS. The ATCS will allow the trading and holding of ERCs that qualify for Clean Power Plan compliance in a system that also will be used to determine compliance. Quarterly, an affected EGU under the federal plan must submit information and data consistent with part 75.[87] These quarterly submission dates are the 30th of April, July, October and January corresponding with the quarterly data ending the month previous the submission deadline (*e.g.,* an April 30, 2024 submission would include data from January through March of 2024). The data that are posted online would be publicly available.

Non-EGU ERC generating sources are required to submit generation data annually (see section IV.C.3 of this preamble for a comprehensive discussion of non-EGU ERC generating sources). The data must follow the EM&V procedures delineated in section IV.D.8 of this preamble. Because of the required rigor of the EM&V process, the EPA provides a time frame of January 1 to June 1 of the year that follows the data's inception to complete all EM&V processes (*e.g,* 2024 RE data must go through the EM&V process and be submitted to the EPA no later than June 1, 2025). After receiving all emission and generation data from ERC generating sources and affected EGUs, the EPA will issue ERCs through a NODA as described in section IV.D.6 of this preamble. The EPA is proposing to issue ERCs annually. ERCs are acquired and traded throughout the compliance period. An affected EGU is responsible to hold sufficient ERCs that qualify for Clean Power Plan compliance in its ATCS compliance account by November 1 at midnight of the year following the conclusion of the compliance period.[88]

The process for transferring ERCs from one account to another is quite simple. A transfer would be submitted providing, in a format prescribed by the agency, the account numbers of the accounts involved, the serial numbers of the ERCs involved, and the name and signature of the transferring authorized account representative or alternate. If the transfer form containing all the required information were submitted to the EPA and, when the Administrator attempted to record the transfer, the transferor account included the ERCs identified in the form, the Administrator would record the transfer by moving the ERCs from the transferor account to the transferee account within 5 business days of the receipt of the transfer form.

10. Compliance With Emissions Standards

Once the compliance period has ended, affected EGUs would have a window of opportunity to evaluate their reported emissions and obtain any ERCs that they might need to cover their emissions during the compliance period. The agency proposes to require sources to demonstrate compliance, *i.e.,* ERC true-up, on November 1 of the year after the last year in the compliance period. For example, if the first compliance period comprises the three years 2022, 2023, and 2024, then the ERC transfer deadline[89] for that first compliance period (after which point the EPA would evaluate compliance) would be on November 1, 2025. The agency also requests comment on an earlier ERC transfer deadline, such as June 1 or March 1, of the year after the last year in the compliance period. Each ERC issued in the proposed rate-based trading program would, if applied, be averaged into the compliance rate as one MWh of energy with zero CO_2 emissions deemed associated with it for the compliance period that includes the year for which the ERC was issued or be averaged into a later compliance period. Consequently, each affected EGU would need, as of the ERC transfer deadline, to have in its compliance account enough ERCs usable for its compliance obligations for the compliance period. The authorized account representative could identify specific ERCs to be applied, but, in the absence of such identification or in the case of a partial identification, the Administrator would deduct on a first-in, first-out basis. The ERCs that are used to meet compliance obligations are moved from the compliance account to the EPA's retirement account. ERCs that are deducted for compliance will remain in the system in an EPA account, which ensures they will not be used again.

The EPA will use the submitted generation, CO_2 emissions and ERCs in the affected EGU's compliance account to calculate an average emission rate for the EGU. It is the responsibility of an affected EGU to calculate the number of ERCs that will need to be held in a compliance account to meet the EGU's compliance obligations. The method for determining the quantity of ERCs needed to meet compliance obligations has been discussed previously in an example. To reiterate the process, the affected EGU would need to solve for the number of zero-emitting MWh (*i.e.,* ERCs) that would need to be added to the total MWh of the EGU to make the adjusted emission rate equal to the emission standard.

$$\text{Adjusted Emission Rate} = \frac{\text{Mass of CO2 emitted (lbs)}}{\text{Generation (MWh)} + \text{MWh ERCs}}$$

This equation can be rearranged to:

$$\text{MWh ERCs} = \frac{\text{Mass of CO2 emitted (lbs)}}{\text{Adjusted Emission Rate }(\frac{\text{lbs}}{\text{MWh}})} - \text{Generation (MWh)}$$

[87] See section IV.D.11 of this preamble for more information.

[88] This true-up process is further described in section IV.D.10 of this preamble.

[89] The "ERC transfer deadline" is the deadline for transferring allowances that can be used for compliance in the previous compliance period to a source's compliance account.

If an affected EGU fails to hold sufficient ERCs to comply with its emission standard then, upon notification of the deficiency, the owners and operators of the affected EGU must provide, for deduction by the Administrator, two ERCs as soon as available for every ERC that the owners and operators failed to hold as required to cover emissions, in addition to the ERCs owed for compliance in that next period. The owed ERCs will be deducted from the EGU's compliance account as soon as they are available in this account; the Administrator will not wait until the next true-up date to make this deduction. The two ERCs owed for each ERC needed for compliance but not supplied is in addition to any other recourse provided in sections 113(a)–(h) or section 304 of the CAA. This requirement to surrender two times the ERCs needed to make up the shortfall for the prior period is an ongoing obligation until compliance is achieved, and there is an ongoing obligation to comply in the current period. Failure to surrender these replacement ERCs is an additional violation that may be subject to federal enforcement. The EPA solicits comment on sources owing two ERCs to make up for each insufficient ERC in previous compliance periods and whether two for one is the proper make-up rate or whether there should be a stricter or a more lenient ratio.

The EPA believes that it is important to include a requirement for an automatic deduction of ERCs. The deduction of one ERC per ERC that the owners and operators failed to hold would offset this failure. The deduction of another ERC per ERC that the owners and operators failed to hold provides a strong incentive for compliance with the ERC-holding requirement by ensuring that non-compliance would be a significantly more expensive option than compliance. This is consistent with other existing trading programs.

11. Other ERC Tracking and Compliance Operations Provisions

These sections also would provide that the Administrator could, at his or her discretion and on his or her own motion and consistent with existing federal trading programs, correct any type of error that he or she finds in an account in the ATCS. In addition, the Administrator could review any submission under the rate-based trading program, make adjustments to the information in the submission, and deduct or transfer ERCs based on such adjusted information. These provisions are a standard part of other trading programs administered by the EPA including the ARP and the CSAPR (*see, e.g.,* 40 CFR 72.96, 73.37, 97.427, and 97.428). The EPA solicits comment on potential alternatives for error correction that may be simpler or more efficient.

12. Banking of ERCs

The EPA is proposing to allow unlimited banking of ERCs within and between the interim and final compliance periods. This means that if an affected EGU has more ERCs than are necessary during true-up, it may save (*i.e.,* bank) those ERCs for application during a future compliance period. The EPA requests comment on whether there should be a quantitative limit or cap on the number of ERCs that can be banked. The EPA also requests comment on whether an ERC should be eligible to be banked between the interim and final compliance periods. The EPA is also proposing that ERCs will not expire after any duration of time. Other trading rules that the EPA has instituted (*e.g.,* CSAPR) do not have expiration on the tradable properties. The EPA requests comment on the shelf-life of an ERC.

ERC ''borrowing'' is a flexibility that the EPA is not proposing, but is soliciting comment on. ERC borrowing is the concept that an affected EGU may use an ERC that the EGU will acquire in a future compliance period to meet its current compliance obligations. The EPA requests comment on a methodology that would allow ERC borrowing while maintaining the integrity of the compliance obligations. The EPA also has reservations concerning this concept due to the fact that future ERC generation is not guaranteed.

13. Emissions Monitoring and Reporting

The EPA would require that emission and generation data be reported to the EPA quarterly starting on April 30, 2022, and continuing every 3 months thereafter (*i.e.,* the 30th of April, July, October, and January). The EPA proposes that affected EGUs subject to the rate-based federal plan trading program would monitor and report CO_2 emissions in accordance with 40 CFR part 75. The EPA is proposing to require affected EGUs in all states covered by the rate-based federal plan trading program to monitor and report CO_2 emissions by and output data by January 1, 2022. Quarterly reporting would be required, with each quarterly report due to the Administrator 30 days after the last day in the quarter. The reporting would be in accordance with 40 CFR 75.60. The use of 40 CFR part 75 certified monitoring methodologies would be required. Many affected EGUs that might be covered by the proposed federal plans will generally have no changes to their monitoring and reporting requirements and will continue to monitor and submit reports under 40 CFR part 75 as they have under existing programs. The EPA anticipates fewer than 50 (approximately 10 of these affected EGUs are coal fired with the remainder being gas and oil fired that will qualify for an excepted monitoring methodology) affected EGUs, that would not otherwise be subject to the ARP, will have to purchase and install additional continuous emissions monitoring system (CEMS) and data handling systems or upgrade existing equipment in order to meet the monitoring and reporting requirements of this program. Several of the affected EGUs not otherwise subject to the ARP are subject to the MATS program and therefore will have already installed stack flow rate and/or CO_2 monitors in order to comply with the MATS rule which are also necessary to comply with this rule. The CEMS used to comply and report data for MATS will be used for this rule to generate and report CO_2 emissions data without having to install duplicative monitors. The same CO_2 and stack gas flow rate monitored data used in conjunction with mercury and other CEMS to calculate a toxic pollutant emission rate may be used to calculate a CO_2 mass or CO_2 emission rate for this program. The Regional Greenhouse Gas Initiative (RGGI), ARP, MATS and this rule all refer to CEMS installed and certified in accordance with 40 CFR part 75. RGGI and ARP currently require the reporting of CO_2 mass emissions on an hourly basis and cumulative totals at the end of each calendar quarter. The same monitors and data collected may be used for multiple purposes for RGGI, ARP, MATS and this rule. Relying on the same monitors that are certified and quality assured in accordance with 40 CFR part 75 ensures cost efficient, consistent, and accurate data that may be used for different purposes for multiple regulatory programs. The majority of the affected EGUs covered by this rule are already affected by the Acid Rain and/or RGGI programs and will have minimal additional monitoring and reporting requirements.

The EPA also requests comment on requiring monitoring and reporting of CO_2 mass and net generation for the year before the initial compliance period begins, *i.e.,* to commence January 1, 2021. Only monitoring and reporting would be required in 2021—compliance with an enforceable emission standard would commence on the compliance period schedule that is detailed in section III.D of this preamble.

E. Federal Plan and State Plan Interactions

1. Interstate Trading

The EPA proposes that all affected EGUs within states that are covered by the federal plan, if a rate-based federal plan is finalized for two or more states, would be allowed to trade with one another since there will be an assured commonality in the ERC currency and criteria surrounding the trading program. In addition, the EPA proposes, consistent with the provision for ''ready-for-interstate-trading'' plans in the EGs, that affected EGUs located in states with approved ready-for-interstate-trading state plans using the subcategorized uniform rate standards, and a common credit currency (*i.e.,* ERCs representing one zero-emitting MWh) may trade with affected EGUs operating under the federal trading program established in this federal plan.

Rate-based EGUs subject to the federal plan and rate-based EGUs in ready-for-interstate-trading state plans will be able to trade ERCs seamlessly across jurisdictional borders because of the assurances of being presumptively approvable. Ready-for-interstate-trading states must submit information that lists all affected EGUs and the EGU type to the Administrator to be able to trade within the federal trading program. To be able to trade in the federal trading program an affected EGU that is subject to a ready-for-interstate-trading state plan must: (1) Certify and authorize a designated representative per section IV.D.1 of this preamble; and (2) register a general account in the federal trading program, ATCS, in order to have a means of transferring ERCs with entities operating in the federal trading program. An affected EGU under a state plan will not register a compliance account in the federal system because it will not be demonstrating compliance under the federal plan. Compliance will be achieved in the affected EGU's corresponding state plan. Affected EGUs under a state plan have the ability to acquire ERCs through the federal trading program. These ERCs will be stored in the EGU's general account in the federal trading program. To use these ERCs for compliance purposes, the ERCs must be transferred to the EGU's compliance account in the state's program. The EPA proposes to provide software to states to maintain a state's compliance and tracking program. A state's program will have the capability to interact with the federal trading program and software, ATCS, for transferring ERCs if the state is ready-for-interstate-trading. A state's program can be tailored to meet its needs while still providing a platform for a state to be transferring ERCs between the state's system and the federal trading program. ERCs can flow between a state system and the federal trading program bilaterally. The EPA acknowledges that states may have additional criteria for generating ERCs that are not outlined as part of the federal plan, but because the EPA will have vetted these criteria through a state plan approval these ERCs will be able to be traded within the federal trading program.

2. Treatment of States Entering or Exiting the Trading Program

The EPA proposes that a rate-based trading federal plan may be replaced by a state plan for a future compliance period. The EPA is proposing that a state must transition to a state plan at the conclusion of a federal plan compliance period. The EPA requests comment on whether there are reasons that a state should be allowed to transition from a federal plan to a state plan in the middle of a compliance period and if so what requirements should be put in place to do so while ensuring the integrity of both the federal plan and the state plan and while enabling the affected EGUs covered by the plans to understand and meet their compliance requirements. If a state subject to the federal plan transitions to a state plan, any affected EGU impacted by the change remains responsible for meeting any outstanding obligations under the federal plan. To make the transition to a state plan, a state must have an approved state plan as laid out in sections VIII.D and VIII.E of the final EGs.

V. Mass-Based Implementation Approach

A. Trading Program Overview

In addition to the rate-based implementation approach discussed above, the EPA is proposing a mass-based implementation approach for the federal plan. As with the rate-based approach, this proposed federal plan is also a proposed model trading rule that states can adopt. The mass-based approach that the agency proposes to implement is a mass-based trading program (*i.e.,* an emissions budget trading program, also referred to as an ''allowance system''). This section provides a brief overview of the proposed mass-based trading program. The next sections describe the various elements of the proposed trading program in further detail.

A mass-based trading program establishes an ''aggregate emissions limit'' that specifies the maximum amount of emissions authorized from affected EGUs included in the program, and creates allowances that authorize a specific quantity of emissions. The total number of allowances created are equal to, and constitute, the emissions budget or the aggregated emissions limit expressed in terms of short tons of emissions. The EPA is proposing that allowances be issued in short tons for the federal plan.

Each facility with affected EGUs in the program must surrender allowances equal in number to the quantity of the emissions of its affected EGUs during the compliance period. A facility with affected EGUs may buy allowances from, or transfer or sell allowances to, other affected EGUs or other entities that participate in the market. A mass-based trading program provides sources with great flexibility in choosing compliance strategies.

In the proposed mass-based trading program for the federal plan, the aggregate emissions limit for a state is its statewide mass-based emission goal (or ''mass goal'') as finalized in the Clean Power Plan EGs. The proposed approach to linking states for interstate allowance trading is detailed in section III.A.1 of this preamble; in an interstate trading program the aggregate emissions limit is the sum of the mass goals for the covered states.

The EPA believes that a broad trading region provides greater opportunities for cost-effective implementation of controls compared to a smaller region. Therefore, the agency proposes that an affected EGU in any state covered by the proposed mass-based trading federal plan may use for compliance an allowance distributed in any other state covered by the mass-based trading federal plan. The EPA also proposes to provide for allowance trading between affected EGUs and other entities in states with approved mass-based-trading state plans that meet the conditions specified in section III.A.1 of this preamble, above, and affected EGUs and other entities in any state covered by the federal plan mass-based trading program.

A mass-based trading program can provide environmental certainty at lower cost than other policy mechanisms, because it assures the specified emissions outcome while maximizing compliance flexibility available to individual affected EGUs. Further, allowance banking in such a program creates an incentive to make reductions earlier than required. Mass-based trading programs are relatively simple to operate, which reduces administrative time and cost. Additionally, to inform the mass-based trading approach proposed here, the EPA draws upon more than two decades of experience implementing federally-administered mass-based emissions budget trading programs including the ARP SO_2 trading program, the NO_X Budget Trading Program, CAIR, and CSAPR.

In the proposed mass-based trading program federal plans, the emissions limits in each state would be the mass goals that the EPA promulgated in the Clean Power Plan EGs (if there is interstate trading then the sum of the mass goals for the states in the trading program would constitute the aggregate emissions limit). The total amount of allowances distributed in each state for each year would sum to the state's mass goal for that year. As detailed in section V.E of this preamble, the EPA is proposing that a state covered by the federal plan can determine its own approach to distribute allowances, and believes that state allocation has important merits. The EPA would distribute allowances in a state if the state does not choose to do so, as detailed below.

Each allowance would authorize the emission of one short ton of CO_2 during the compliance period applicable to the allowance's vintage year or a later compliance period. The proposed approach to distribute allowances, including three types of allowance set-asides, is discussed in section V.D of this preamble, below.

After each compliance period, an affected EGU would surrender for compliance an amount of allowances equal to its emissions during the course of the compliance period. See section V.C of this preamble for the proposed length of the multi-year compliance periods. Allowances could be transferred, bought, sold, or banked (carried over for future use) and any party could participate in the allowance market. The EPA is not proposing allowance ''borrowing'' (*i.e.,* the bringing forward of future-period allowances for use in an earlier period); the multi-year compliance periods inherently provide the flexibility to schedule relatively greater emission reductions for later years within each period, as discussed further in section V.C of this preamble. In the proposed mass-based trading program, the emission standard applied to individual affected EGUs is the requirement to surrender emission allowances equal to reported emissions for each compliance period.

The EPA also proposes that a state may choose to replace the federal plan allowance-distribution provisions with its own allowance-distribution provisions (*i.e.,* to determine the distribution of allowances for its EGUs or other entities) using a state allowance-distribution methodology. State allowance distribution can have important advantages, because it allows a state to design and shape allowance allocation to its specific goals and characteristics, and because states may have additional flexibility on allocation approaches, including auctions. See section V.E of this preamble for further discussion of the proposed approach for state-determined allowance-distribution methodologies.

This proposed requirement to hold and surrender allowances equal to emissions for each compliance period would apply to all reported emissions from a facility's affected EGUs including any emissions from co-fired biomass if biomass is included as an eligible measure. Section IV.C.3 of this preamble discusses an approach on which the EPA requests comment on the inclusion of biomass as an eligible measure and on a proposed option where the agency would identify qualified biomass feedstocks (*i.e.,* biomass feedstocks that are demonstrated to be a method to control increases of CO_2 levels in the atmosphere) and potential methods for demonstrating compliance, and thus reduce the mass emissions attributed to a biomass co-fired affected EGU. If the EPA took such an approach, then for purposes of compliance with the proposed mass-based federal plan trading program, the affected EGU would need to hold allowances equal to its emissions less the emissions attributed to the co-fired qualified biomass; such an approach would reduce the number of allowances the affected EGU would need to hold to demonstrate compliance. The EPA requests comment on this approach.

B. Statewide Mass-Based Emissions Goals

In the Clean Power Plan EGs the EPA established statewide mass-based emission goals (''mass goals'') for all states that are equivalent to the rate-based goals. As discussed in section V.C of this preamble, below, the EPA proposes to implement the mass-based trading program with multi-year compliance periods that are consistent with the compliance timing provisions in the Clean Power Plan EGs, *i.e.,* two 3-year compliance periods followed by a 2-year compliance period in the Interim Period, and successive 2-year periods in the Final Period. In the Clean Power Plan EGs, the EPA established mass goals for all states for this pattern of compliance periods. The EPA proposes to use those mass goals promulgated in the Clean Power Plan EGs as the mass limits (*i.e.,* emissions budgets) for any state covered by the mass-based trading program (or, if implementing interstate trading, then the EPA would use the sum of a covered group of states' mass goals as the aggregate mass limit). The EPA is not opening for comment the determinations, made in the Clean Power Plan EGs, of each state's mass goals. The mass goals are provided for convenience in Table 8 of this preamble.

TABLE 8—STATEWIDE MASS-BASED EMISSION GOALS (''MASS GOALS'')

[Short tons]

State	Interim period			Final period
	Step 1 2022–2024	Step 2 2025–2027	Step 3 2028–2029	2030–2031 and thereafter
Alabama	66,164,470	60,918,973	58,215,989	56,880,474
Arizona *	35,189,232	32,371,942	30,906,226	30,170,750
Arkansas	36,032,671	32,953,521	31,253,744	30,322,632
California	53,500,107	50,080,840	48,736,877	48,410,120
Colorado	35,785,322	32,654,483	30,891,824	29,900,397
Connecticut	7,555,787	7,108,466	6,955,080	6,941,523
Delaware	5,348,363	4,963,102	4,784,280	4,711,825
Florida	119,380,477	110,754,683	106,736,177	105,094,704
Georgia	54,257,931	49,855,082	47,534,817	46,346,846

TABLE 8—STATEWIDE MASS-BASED EMISSION GOALS ("MASS GOALS")—Continued

[Short tons]

State	Interim period			Final period
	Step 1 2022–2024	Step 2 2025–2027	Step 3 2028–2029	2030–2031 and thereafter
Idaho	1,615,518	1,522,826	1,493,052	1,492,856
Illinois	80,396,108	73,124,936	68,921,937	66,477,157
Indiana	92,010,787	83,700,336	78,901,574	76,113,835
Iowa	30,408,352	27,615,429	25,981,975	25,018,136
Kansas	26,763,719	24,295,773	22,848,095	21,990,826
Kentucky	76,757,356	69,698,851	65,566,898	63,126,121
Lands of the Fort Mojave Tribe	636,876	600,334	588,596	588,519
Lands of the Navajo Nation	26,449,393	23,999,556	22,557,749	21,700,587
Lands of the Uintah and Ouray Reservation	2,758,744	2,503,220	2,352,835	2,263,431
Louisiana	42,035,202	38,461,163	36,496,707	35,427,023
Maine	2,251,173	2,119,865	2,076,179	2,073,942
Maryland	17,447,354	15,842,485	14,902,826	14,347,628
Massachusetts	13,360,735	12,511,985	12,181,628	12,104,747
Michigan	56,854,256	51,893,556	49,106,884	47,544,064
Minnesota	27,303,150	24,868,570	23,476,788	22,678,368
Mississippi	28,940,675	26,790,683	25,756,215	25,304,337
Missouri	67,312,915	61,158,279	57,570,942	55,462,884
Montana	13,776,601	12,500,563	11,749,574	11,303,107
Nebraska	22,246,365	20,192,820	18,987,285	18,272,739
Nevada	15,076,534	14,072,636	13,652,612	13,523,584
New Hampshire	4,461,569	4,162,981	4,037,142	3,997,579
New Jersey	18,241,502	17,107,548	16,681,949	16,599,745
New Mexico *	14,789,981	13,514,670	12,805,266	12,412,602
New York	35,493,488	32,932,763	31,741,940	31,257,429
North Carolina	60,975,831	55,749,239	52,856,495	51,266,234
North Dakota	25,453,173	23,095,610	21,708,108	20,883,232
Ohio	88,512,313	80,704,944	76,280,168	73,769,806
Oklahoma	47,577,611	43,665,021	41,577,379	40,488,199
Oregon	9,097,720	8,477,658	8,209,589	8,118,654
Pennsylvania	106,082,757	97,204,723	92,392,088	89,822,308
Rhode Island	3,811,632	3,592,937	3,522,686	3,522,225
South Carolina	31,025,518	28,336,836	26,834,962	25,998,968
South Dakota	4,231,184	3,862,401	3,655,422	3,539,481
Tennessee	34,118,301	31,079,178	29,343,221	28,348,396
Texas	221,613,296	203,728,060	194,351,330	189,588,842
Utah *	28,479,805	25,981,970	24,572,858	23,778,193
Virginia	31,290,209	28,990,999	27,898,475	27,433,111
Washington	12,395,697	11,441,137	10,963,576	10,739,172
West Virginia	62,557,024	56,762,771	53,352,666	51,325,342
Wisconsin	33,505,657	30,571,326	28,917,949	27,986,988
Wyoming	38,528,498	34,967,826	32,875,725	31,634,412

* Excludes EGUs located in Indian country within the state.

C. Compliance Timing and Allowance Banking

The EPA proposes to evaluate compliance (*i.e.,* compare emissions from affected EGUs to allowances held by facilities) in multi-year periods. A multi-year compliance period provides greater flexibility to affected EGUs and reduces administrative burden, compared to a single-year compliance period. The EPA seeks to strike a reasonable balance between providing flexibility and reducing burden while assuring that any noncompliance can be addressed in a timely fashion.

The compliance periods in the proposed mass-based trading program would be the same as promulgated in the Clean Power Plan EGs, *i.e.,* the Interim Period would be divided into three compliance periods: A 3-year compliance period (2022 through 2024), a second 3-year compliance period (2025 through 2027), and then a 2-year compliance period (2028 and 2029), for the Interim Period. As in the EGs, the Final Period would be divided into successive 2-year compliance periods commencing in 2030. The EPA would evaluate compliance only after the end of a compliance period in the mass-based trading federal plan, *e.g.,* if a compliance period is 3 years long, the agency would evaluate compliance only after the end of the third year in the period. The EPA is not reopening for comment the compliance periods promulgated in the Clean Power Plan EGs.

Some existing GHG mass-based trading programs (*i.e.,* emissions budget trading programs) use multi-year compliance periods. The RGGI uses 3-year compliance periods, along with intervening compliance requirements. The RGGI intervening compliance requirement is that sources must hold allowances to cover 50 percent of emissions for the first two calendar years of each 3-year compliance period; at the end of each 3-year compliance period sources must hold allowances to cover 100 percent of emissions for the period and allowances already deducted for the intervening requirement are subtracted from the 3-year obligation.[90] The California Air Resources Board (CARB) Cap-and-Trade Program also uses 3-year compliance periods, along with intervening compliance requirements. The CARB intervening requirement is to evaluate compliance on 30 percent of each source's previous year's emissions every year, and evaluate compliance for the remainder of emissions every 3 years.[91] The EPA proposes to evaluate compliance after each multi-year compliance period and is not proposing to implement intervening compliance requirements such as those in the RGGI or CARB programs, however, the agency requests comment on the inclusion of such requirements.

The EPA recognizes that the compliance periods provided for in this rulemaking are longer than those historically and typically specified in CAA rulemakings. As reflected in long-standing CAA precedent, ''[t]he time over which [the compliance standards] extend should be as short term as possible and should generally not exceed one month.'' *See e.g.,* June 13, 1989 Guidance on Limiting Potential to Emit in New Source Permitting and January 25, 1995 Guidance on Enforceability Requirements for Limiting Potential to Emit through SIP and § 112 Rules and General Permits. The EPA determined that the longer compliance periods provided for in this rulemaking are acceptable in the context of this specific rulemaking because of the unique characteristics of this rulemaking, including that CO_2 is long-lived in the atmosphere, and this rulemaking is focused on performance standards related to those long-term impacts.

The EPA proposes that allowances may be banked for use in any future compliance period, with no restriction on the use of banked allowances, including from the Interim Period (2022 through 2029) into the Final Period (2030 and thereafter). The agency requests comment on the proposal to provide for unlimited allowance banking including the banking of Interim-Period allowances for use during the Final Period.

Allowance ''borrowing'' is a type of timing flexibility wherein allowances from a future compliance period may be ''brought forward'' and used for compliance in an earlier compliance period (thus reducing the amount of allowances available for the future period). The EPA notes that the proposed multi-year compliance periods inherently provide the flexibility to emit at relatively higher amounts in earlier years of a given compliance period by using allowances from future years within each compliance period (*e.g.,* if the first compliance period covers years 2022 through 2024, a vintage 2024 allowance could be used to cover a ton emitted in 2022). The EPA is not proposing to allow allowance borrowing across compliance periods in the mass-based trading federal plans; however the agency requests comment on the use of borrowing across compliance periods.

Allowance borrowing across compliance periods would increase the complexity of the proposed mass-based trading program and reduce the flexibility for states to replace the federal plan with an approved state plan. First, in order for borrowing to occur, the EPA would have to make allowances from future compliance periods available early so that sources could use these future allowances in earlier compliance periods. The EPA proposes to record allowances in source accounts for one compliance period at a time in order to maximize the opportunities for a state to replace the federal plan (or replace the allowance-distribution provisions of the federal plan) with an approved state plan (or approved state allowance-distribution methodology). The EPA proposes to allow a state to replace the mass-based trading federal plan (or the federal plan allowance-distribution provisions) with a state plan (or state allowance-distribution methodology) for a compliance period for which the agency has not yet recorded allowances in source accounts. Recording allowances for multiple compliance periods at once—in order to make future-period allowances available for borrowing—would therefore limit these opportunities for states to take over implementation (or implementation of the allowance-distribution).

If allowance borrowing from a future compliance period were allowed, and the EPA provided the opportunity for a state to replace the federal plan for a year for which allowances had already been borrowed and retired for compliance in an earlier period, those borrowed allowances would constitute additional emissions beyond the levels specified in the Clean Power Plan EGs. In that event, the EPA would then need to address whether and how to remove allowances from circulation to prevent inflation of the allowable emissions at affected EGUs in the remaining states subject to the federal plans (to ''repay'' the borrowed allowances). To avoid disruption to sources already subject to the mass-based trading federal plan, the EPA is not proposing to allow allowance borrowing across compliance periods.

Although not proposing to provide for allowance borrowing across compliance periods, the agency requests comment on the potential inclusion of allowance borrowing in the proposed mass-based trading federal plans, including from how far into the future to allow allowances to be borrowed, how inclusion of borrowing would affect opportunities for states to take over implementation of the EGs (or implementation of the allowance-distribution provisions in the mass-based trading federal plan), how to address removing the extra allowances from circulation that would result if borrowed allowances originate in a state that subsequently withdraws from the mass-based trading program, and on other complexities that borrowing across compliance periods would introduce.

The agency proposes to require sources to demonstrate compliance, *i.e.,* allowance true-up, on May 1 of the year after the last year in the compliance period. For example, if the first compliance period comprises the three years 2022, 2023, and 2024, then the allowance transfer deadline[92] for that first compliance period (after which point the EPA would evaluate compliance) would be on May 1, 2025. The agency also requests comment on an earlier or later allowance transfer deadline.

The EPA proposes to evaluate compliance (*i.e.,* allowance true-up) at the facility level, not at the individual affected-EGU level, in the mass-based trading program. Facility-level compliance may ease implementation compared to unit-level compliance; each facility has a single compliance account in which to hold allowances to cover emissions from all its affected EGUs rather than having individual unit-level compliance accounts. Fewer accounts may make it easier for the designated representatives to manage their allowances. The EPA has adopted facility-level compliance in previous emissions budget-trading programs including the ARP, *see* 70 FR 25162, at 25296–98 (May 12, 2005); the CAIR FIP, *see* 71 FR 25328, at 25365 (April 28, 2006); and the CSAPR, *see* 75 FR 45210, at 45323 (August 2, 2010). The EPA

[90] RGGI, Summary of RGGI Model Rule changes: February 2013. *http://www.rggi.org/docs/ProgramReview/_FinalProgramReviewMaterials/Model_Rule_Summary.pdf* Accessed June 9, 2015.

[91] Overview of ARB Emissions Trading Program. *http://www.arb.ca.gov/cc/capandtrade/guidance/cap_trade_overview.pdf.* Accessed June 9, 2015.

[92] The ''allowance transfer deadline'' is the deadline for transferring allowances that can be used for compliance in the previous compliance period to a source's compliance account. For further information see section V.G of this preamble.

would continue to track unit-level emissions—while evaluating compliance at the facility level—allowing us to track increases and decreases of pollutants at individual EGUs.

D. Initial Distribution of Allowances

Establishing a mass-based trading program requires that policymakers establish an approach for the initial distribution of allowances, historically referred to as ''allowance allocation.'' The EPA believes that states may be well positioned to design their own allowance distribution approach because they can take into account a wide range of considerations and tailor decisions to the particular characteristics and preferences of their state. The EPA proposes that states have the flexibility to determine their own approach for distributing allowances in the federal plan, through a process that is detailed in section V.E of this preamble. The EPA believes that states should have the opportunity to make decisions about allowance distribution and that they may have additional flexibility on approaches, including allowance auctions. The EPA is also proposing an allocation approach that we intend to use in the event we implement the federal plan in a state that does not choose to determine its own allowance-distribution approach. The EPA requests comment on all of these, and any other, approaches to distribute allowances.

The initial allowance allocation approach that is based on historical data does not affect the environmental results of the program or generation patterns; regardless of the manner in which allowances are initially distributed, the finite total number of allowances limits allowable emissions across all affected EGUs. Allowance allocations also are not intended to prescribe or suggest any unit-level compliance requirements nor do they limit unit-level operational flexibility, because a mass-based trading program provides operators of affected EGUs with the flexibility to buy, sell, or bank allowances. Allowance allocation is simply a procedure by which allowances are distributed into the marketplace so that they may be available for affected EGUs to acquire as desired to authorize emissions under the program. However, because these allowances are finite in number and thus a limited resource, they have value, and as a result, initial allowance allocations may raise issues of equity among recipients.

Thus the agency recognizes that its choice of allocation methodology is important from the perspective of distributional effects, and the importance of selecting an approach that is fair and reasonable in light of this consideration and the overall purpose of CAA section 111 informs the agency's thinking in this proposal. We also invite comment on these considerations, and on any other factors or considerations which commenters believe should inform the allocation method.

The EPA believes that the most reasonable basis for an initial allowance allocation procedure is an approach that uses historical data reported by the affected EGUs subject to the requirement to hold allowances under this program. This approach relies on known data rather than future projections. The EPA believes this approach is preferable because any approach tied to future indicators (*e.g.,* the expected future EGU-level pattern of emissions or the ultimate use of allowances) would depend on future outcomes that the EPA cannot project with perfect certainty in advance. Basing allocation on historical data is also consistent with the EPA's approach to initial allowance allocation under previously established mass-based trading programs.

The EPA proposes to allocate most CO_2 emission allowances to existing affected EGUs in each state covered by a final mass-based trading federal plan, with set-asides for a portion of allowances (discussed in more detail below). For each compliance period, the agency would distribute CO_2 allowances in each covered state in the amount of the state's CO_2 ''mass goal'' (*i.e.,* the state's CO_2 statewide mass-based emission goal as promulgated in the Clean Power Plan EGs) for that compliance period. For example, if a compliance period is 3 years long, the EPA would aggregate and distribute allowances for all 3 years at the same time. The agency is not proposing to allocate allowances to new EGUs, which do not have a compliance obligation under this proposed federal plan. For each year of the program, the agency proposes to allocate most of the allowances directly to affected EGUs using a historical-generation-based approach. The EPA is also proposing three set-asides of allowances, which are detailed below.

Although the EPA cannot anticipate the future EGU-level pattern of emissions, it is possible to consider potential future emission patterns at the source subcategory level. In developing the Clean Power Plan EGs, the agency conducted analysis of emission reduction potential in the two affected EGU source subcategories, *i.e.,* electric utility steam generating units (steam generating units) and NGCC units. With that analysis as a basis, the EPA requests comment on an alternative allocation approach that would first divide the total number of allowances from each state's mass goal into source subcategories based on analysis done in developing the source category-specific CO_2 emissions performance rates promulgated in the EGs and then allocate to affected EGUs within each category based on shares of historical generation. This alternative is described later in this section.

The EPA recognizes that states may prefer different approaches to distribute CO_2 allowances from the EPA's approach and that there may be advantages in having states tailor and apply their own allocation approach. Therefore, the agency is proposing that a state may choose to replace the federal plan allowance-distribution provisions with its own allowance-distribution provisions, using any approach to distribute allowances that the state chooses, including methods that the EPA is not proposing here, provided that the state's approach addresses emissions leakage and includes a Clean Energy Incentive Program. The proposed requirements for addressing leakage, as well as how the EPA proposes to implement the Clean Energy Incentive Program for the mass-based federal plan, are detailed in sections V.E and V.D.4 of this preamble, respectively.[93] The EPA proposes that a state could choose its own method for distributing allowances for any compliance period including the first period that would commence in 2022. The proposed process for a state to replace federal plan allowance-distribution provisions with its own allowance-distribution provisions is detailed in section V.E of this preamble.

The following sections discuss and request comment on the EPA's proposed approach to allocate CO_2 allowances to affected EGUs based on shares of historical generation, the proposed timing of allowance recordation, three proposed allowance set-asides, allocations to units that change status, and the proposed approach for states to replace federal plan allocation provisions with their own allowance-distribution approaches. In addition, we

[93] As detailed in section V.E in this preamble, we propose that a state that chooses to determine its own allowance-distribution approach under the proposed federal plan must address leakage through its allocation strategy (such as the set-aside approaches in section V.D.3 of this preamble). We request comment on whether a state may make a justification regarding leakage as detailed in section V.E of this preamble.

request comment on alternative allowance distribution approaches—such as auctioning or allocations to load-serving entities—that the EPA or states might adopt. The EPA requests comment on all of these aspects of allowance distribution.

1. Proposed Allocation Approach and Alternatives

The EPA proposes to allocate most of the CO_2 allowances in the mass-based trading program to affected EGUs based on historical generation (output) data. The EPA also proposes three allowance set-asides. The first would set aside a portion of allowances in each state from the first compliance period only; this set-aside is for a proposed Clean Energy Incentive Program that is detailed in section V.D.4 of this preamble. The second would set aside a portion of allowances in each compliance period except for the first period; the EPA proposes to distribute allowances from this set-aside to affected EGUs via an updating output-based approach as detailed in section V.D.3 of this preamble). The third would set aside 5 percent of allowances in each state, in all compliance periods, to be distributed to RE projects as detailed in section V.D.3 of this preamble. In summary, the proposed set-asides include:

(1) Clean Energy Incentive Program. This set-aside would be of first compliance period allowances only.

(2) Output-based allocation set-aside. This set-aside would start in the second compliance period and continue for each compliance period.

(3) Renewable energy set-aside. This set-aside would be implemented in all compliance periods.

This section describes the proposed historical-generation-based approach that the agency would use to allocate all allowances except for the set-aside allowances. The EPA is proposing affected-EGU-level allocations (based on available data) in every state. Further detail on this proposed allocation approach is provided in the Allowance Allocation Proposed Rule TSD in the docket. The affected-EGU-level allocations resulting from this proposed historical-generation-based approach are provided in the docket in an appendix to the TSD. The agency requests comment on the proposed historical-generation-based allocation approach and on other allocation approaches.

The EPA proposes to allocate the historical-generation-based portion of the allowances (*i.e.,* the mass goal minus the set-asides) [94] to individual affected EGUs based on each affected EGU's share of the state's historical generation, using 2010 through 2012 data. The calculation steps for this proposed historical-generation–based allocation approach are as follows:

(1) For each unit in the list of likely affected EGUs in each state, identify annual net generation values for the historical period of 2010 through 2012 (reflecting affected-EGU-specific generation assumptions incorporated in the data adjustments, *e.g.,* assumed capacity factor for ''under construction'' units). For a year for which an affected EGU has no generation data (*e.g.,* a year before the year when a unit started operating), assign the affected EGU a value of zero.[95] (See step 2, below, for how zero values would be treated in the calculations.)

The EPA proposes to use a 3-year historical period (*i.e.,* 2010 through 2012) to reflect unit-level operations over time. In the Clean Power Plan EGs, the EPA identified a reasonable basis for using aggregate data at the regional level largely based on the most recent data year (in that case, 2012) to inform the establishment of category-wide EGs (as opposed to individual, unit-specific parameters). As a distinct matter, in this context the EPA is considering data at the unit level to inform unit-specific initial allowance allocations; notwithstanding that these allowance allocations do not impose any unit-level compliance requirements in and of themselves, the EPA finds it reasonable to consider a multi-year data period to inform unit-level initial allocations in order to consider a broader range of unit-specific operations over time.

(2) Determine each affected EGU's average generation value by averaging all (non-zero) 2010 through 2012 annual generation values for the unit. The proposed approach would use only non-zero values in calculating a unit's average generation. For example, if generation data for a unit were available for only 2011 and 2012 then the EPA would only use the 2011 and 2012 values to determine the unit's unadjusted average generation value. The EPA included generation from all units in the historical data set in the proposed allowance calculations and calculated allowances for all such units; the agency requests comment on the treatment of generation from and allocations to units that operated in the historical data set but retire before the start of the program.

(3) In each state, sum the average generation values from all affected EGUs to obtain that state's ''total average historical generation.''

(4) Divide each affected EGU's average generation value by the state's total average historical generation to determine that affected EGU's share of the state's total average historical generation.

(5) Multiply each affected EGU's share of the state's total average historical generation by the historical-generation-allocation portion of the state's mass goal (*i.e.,* the state's mass goal minus the set-asides) to determine that affected EGU's allocation.

The agency believes that this proposed historical-generation-based allocation approach is a reasonable approach for several reasons:

• The agency believes that the proposed historical-generation-based approach maximizes transparency and clarity of allowance allocations. The EPA has placed in the docket the historical generation data and the calculations used to determine the proposed affected-EGU-level allocations. The agency also placed the proposed affected-EGU-level allocations, resulting from these calculations, into the docket. These calculations can be relatively easily replicated.

• To calculate allocations, the EPA proposes to use historical affected-EGU-level net generation data compiled using a methodology similar to the Emissions & Generation Resource Integrated Database methodology. The proposed calculation approach is described further below and in the Allowance Allocation Proposed Rule TSD in the docket. The historical-data methodology is described in the CO_2 Emission Performance Rate and Goal Computation TSD for Clean Power Plan Final Rule. The majority of the generation-unit-level data in this approach are from reports that emissions sources submit to the EPA under 40 CFR part 75 and to the EIA on forms EIA–860 and EIA–923. The EPA believes these are the best data available to the agency at the time of this proposed rule for calculating affected-EGU-level allocations.

• Allocating based on historical data (as opposed to data not yet reported)

[94] In the first compliance period this would be the mass goal minus the Clean Energy Incentive Program set-aside and the RE set-aside. In all other compliance periods this would be the mass goal minus the output-based allocation set-aside and the RE set-aside.

[95] The EPA proposes that for affected EGUs that were under construction and began operation during 2012 or after 2012 (and thus don't have a full year of generation data from the 2010 through 2012 period), the allocation calculations be based on the same 2012 generation estimate as the agency used in the Clean Power Plan EGs for the goal-setting calculations. That is, the EPA proposes to estimate 2012 generation for such units based on a unit's net summer capacity and assuming a 55 percent capacity factor for gas units and a 60 percent capacity factor for steam units.

allows for the distribution of allowances prior to the start of the program, which can facilitate compliance planning.

The proposed approach is transparent, based on reliable data, and, like the approaches used in the NO_X SIP Call, the ARP, and CSAPR, based on historical data. For all these reasons, the agency believes that it is appropriate to use a historical-generation-based allocation methodology in this proposed rule. The EPA also requests comment on a historical-data approach based on historical emissions.

The proposed historical-data-based allocations approach would not generally affect the ultimate pattern of generation across individual power plants, as compared to other methods of allocation. The combination of plants, and their contributing generation, that will be used to meet a particular demand for electric power will be based on the relative efficiency (cost of production) of available plants. The relevant measure of this efficiency is the marginal cost of generation, which for a particular power plant would be the sum of the cost of additional fuel to generate an additional MWh, additional maintenance costs to increase output by an additional MWh, and costs associated with the additional emissions that result from generating an additional MWh. In a mass-based trading program, additional emissions must be covered by additional allowances, so the cost of emitting is the price of the allowances that must be consumed to authorize those emissions. These emissions-related costs of electricity production are the same regardless of whether the allowances used to cover those emissions were initially allocated to the user or whether they were acquired subsequently in the marketplace.

The same concept applies to any other cost of electricity production. For example, a coal-fired EGUs operator would account for the cost of consuming coal to produce generation whether or not the coal was discovered already on-site, given to the unit at ''no charge'', or purchased from the marketplace; in all cases, the combustion of that coal consumes its value (*i.e.,* it can no longer be sold). Similarly, the approach taken to distribute allowances does not affect the cost accounting for emissions at units because the use of any tradable allowance has an opportunity cost—a firm loses the opportunity of selling an unneeded allowance when it emits an additional ton. Because a firm loses the opportunity of selling an unneeded allowance when it emits an additional ton, even the emission of a ton covered by a ''free'' allowance causes the generator to incur the cost of emissions based on the market price of allowances the owner must forgo by emitting that ton and using that allowance.

The proposed historical-data-based allocation approach would not be expected to have any effect on freely competitive electricity markets, because the marginal cost of emitting under the mass-based trading program is determined by the level of the overarching mass goals and is not affected by the distribution of the underlying allowances. This marginal cost of emitting is what will inform prices, outputs, and competition among power plants. While cost-of-service markets are structured differently from competitive markets, the regulated utility still makes the dispatch decision on the basis of marginal costs among the units in its fleet, which is not affected by the amount of allowances that any particular unit in that fleet was initially allocated (assuming a competitive allowance market).

The EPA recognizes that some stakeholders are concerned about the potential future distribution of emissions at the facility level, and possible effects on communities. However, for the reasons discussed in the above paragraphs, allowance allocations that do not change based on future activity (such as allocations under the proposed historical-generation-based approach) do not affect the distribution of emissions under the program. This proposed rule is expected to achieve significant emission reductions across the electric power sector; see section IX of this preamble for discussion of anticipated broad benefits to communities.

In addition to the proposed historical-data-based allocations approach, the EPA also requests comment on other allocation approaches. One alternative approach on which the agency requests comment is similar to the proposed approach in that it allocates allowances based on historical generation. However, this alternative approach would divide the total number of allowances from a state's mass goal (minus the set-asides) into affected EGU source categories—based on analysis done in developing the source category-specific CO_2 emissions performance rates promulgated in the Clean Power Plan EGs—before determining unit-level allocations. The EPA requests comment on this alternative approach because dividing the allowances in a state by source category in this manner may result in an initial distribution of allowances that would be closer at the source-category level to the future category-level pattern of emissions, and thus to allowances ultimately used, than the proposed approach. To the extent that this category-level division of allowances is a reasonable proxy for the future category-level emissions pattern under the program, this approach may reduce wealth transfer between parties that occurs as a consequence of a less-anticipatory initial allocation procedure. The EPA cannot observe in advance the future affected-EGU-level pattern of emissions.

In this alternative approach, for each state the EPA would multiply historical steam-generating-unit generation by the steam-generating-unit source category-specific CO_2 emissions performance rate, and multiply historical NGCC-unit generation by the NGCC-unit source category-specific CO_2 emissions performance rate. The EPA would do these calculations for each of the compliance periods in the Interim Period using the glide path interim performance rates, and for the Final Period using the final performance rates. These performance rates are shown in Table 6 in section IV.B of this preamble, above. The EPA established the source category-specific emissions performance rates in the Clean Power Plan EGs (*see* section VI of the final EGs); these rates are not within the scope of this proposed federal plan rulemaking. Next, for each compliance period the EPA would split the total number of allowances from the state's mass goal (minus the set-asides) into affected-EGU source categories in proportion to the values resulting from the above calculation. The EPA would then allocate the steam-generating-unit portion of the allowances to individual SGUs using the same historical-generation-based approach described above, and would also allocate the NGCC-unit portion of the allowances to individual NGCC units using the historical-generation-based approach.

The EPA notes that there are multiple approaches that policymakers may use to distribute allowances, beyond the proposed or alternative allocation approaches we included in this proposed rule. Examples of other allocation approaches include allocating based on historical heat input (fuel) or historical emissions data, rather than historical generation data. The choice to use historical data for allocation (*e.g.,* generation, heat input, or emissions) means that the distribution of allowance value will be based on past behavior. For example, allocations based on historical emissions would benefit those that have historically been the largest emitters, whereas allocations based on historical heat input or generation (output) would benefit those that have historically used the most fuel or generated the most electricity.[96] Alternatively, allocations could be distributed based on projected or observed future activity (*e.g.,* generation, heat input, or emissions).

The proposed and alternative allocation approaches would determine most of the allocations before the start of the program. Other potential allocation approaches would change allocations for future compliance periods based on future activity—referred to as ''updating'' allocations. This proposed rule includes an updating-allocation component, as we are proposing to set aside a portion of the allowances in each state for distribution using an updating output-based approach as detailed in section V.D.3 of this preamble. The EPA requests comment on the use of other updating allocation approaches.

Another allowance allocation approach that could minimize the difference between the initial allowance allocation and the ultimate distributional pattern of allowance use for compliance is to conduct an auction, a process whose express intent is to align the allocation of a scarce good (in this case, the limited authorization to emit CO_2) with the parties most willing to pay for its use. Many ascribe benefits, in terms of economic efficiency, to the use of auctioning as a means of allocating allowances. The EPA notes that some states (*e.g.,* RGGI participating states) have used auctions to distribute allowances and have used auction revenues for a variety of purposes, including the implementation of demand-side EE measures intended to help reduce electricity rate impacts and overall program costs, as well as targeted investments in low-income communities. The EPA believes that if it conducted allowance auctions, any revenue from such auctions received by the agency must be deposited in the U.S. Treasury under federal law.[97] As a result, the EPA notes that states implementing state plans may have greater flexibility than the federal government would to direct auction funds for particular activities. The agency requests comment on the idea of auctioning all, or a portion of, each state's allowances in the proposed federal plan, on how much of each state's allowances to auction if not the entire amount, on the frequency (*e.g.,* yearly or every few years), design of auctions (*e.g.,* spot or advance; first, second-price or other) and who may participate in the auction.

The EPA requests comment on an alternative approach, which is allocating a portion of the allowances to load-serving entities (LSEs) rather than to affected EGUs. LSEs are the entities responsible for delivering power to retail consumers.

Allocation to LSEs can help mitigate bill impacts on electricity consumers when applied in concert with certain additional design features. In particular, if LSEs commit and/or are required to pass through to ratepayers the value from their selling of the allocated allowances, this approach can mitigate the impact of electricity bill increases on consumers that might otherwise result from application of the federal plan. As described in the Allowance Allocation TSD, this type of approach can also help to avoid or mitigate the potential for windfall profits for affected EGUs. The EPA could apply this approach by conditioning the receipt of allowances by LSEs on the pass through to consumers of any allowance value if necessary.

The EPA requests comment on the design and utility of allocating allowances to LSEs to help mitigate electricity price impacts. In particular, the EPA requests comment on options to establish conditions requiring pass through of allowance value and verification of such pass-through, whether it would be appropriate to identify any conditions related to equitable distribution of allowance value among ratepayer categories, as well as the EPA's legal authority to apply any such conditions.

The EPA requests comment on the additional design aspects of any potential allocation to LSEs, including but not limited to the following questions: In particular, what metric should provide the basis for LSE allocation, *e.g.,* electricity demand served by the LSE, population served by the LSE, emissions associated with generation serving the LSE, or some other metric. If emissions are used as the basis for such allocation, what approach should be taken: On a historical basis or a continually updated basis, on the basis of estimated emissions for the relevant region or some other basis, and using what data to calculate such emissions. Also, the EPA requests comment on the form by which LSEs may distribute the allowance value to rate-payers, *e.g.* as a fixed amount, through reduced rates, etc. Finally, the EPA requests comment on what share of the total number of allowances should be distributed to LSEs and what monitoring and reporting requirements may be necessary to support an effective program.

The EPA also requests comment on the proposed historical-generation-based allocation approach, the alternative approach that divides total allowances from a mass goal into source subcategories before allocating to individual affected EGUs within each source category based on historical generation, and on the other alternative approaches described in this section. The EPA also requests comment on allocating allowances to all generation in a state (including non-emitting generation) using a historical-generation-based approach. The agency also requests comment on the proposed allowance set-asides, which are detailed below. The agency requests comment on allocation approaches that may minimize the impact of this proposed rule on small entities. The EPA also requests comment on any other approaches to distribute allowances. The agency notes that we propose to provide that any state may choose to replace the federal plan allocation provisions with an allocation approach of its choosing as discussed below. Finally, with regard to alternative allocation methodologies (either those specifically mentioned in this proposal or other allocation methodologies), the EPA requests comment on how those alternatives would satisfy the requirement that in a mass-based program where new sources are not included as part of the program, the allocation methodology must address leakage to new fossil fuel-fired sources.

2. Timing of Allowance Recordation

The proposed historical-data-based allocation approach—which the EPA proposes to use to allocate all of the allowances in each state except for the set-aside allowances—is a one-time determination that is not updated. The allocations resulting from this approach would be determined prior to the start of the program. The EPA proposes to record the historical-data-based allowances for each compliance period in source accounts prior to the start of each compliance period, and to record allowances for one compliance period at a time. Recording allowances prior to the start of a compliance period provides certainty to affected EGUs of their allocations in advance of when the allowances are needed for compliance and can facilitate long-term planning.

[96] Tools of the Trade, A Guide to Designing and Operating a Cap and Trade Program for Pollution Control, EPA, 2003.

[97] The EPA believes authority to conduct auctions is located in CAA section 111 alone, as well as by its reference to CAA section 110(c) FIPs. The statutory definition of a FIP authorizes ''techniques (including economic incentives, such as marketable permits or auctions of emissions allowances).'' 42 U.S.C. 7602(y).

Recording allowances for one compliance period at a time provides flexibility for a state to replace the federal plan with its own plan in a timely way. As discussed in section V.F of this preamble, the EPA proposes to allow a state to replace the federal plan with its own approved state plan, for a compliance period for which allowances have not yet been recorded (the proposed schedule for allowance recordation is detailed below). The EPA also proposes that a state could choose to replace the federal plan allocations to its affected EGUs (and other entities) with its own allocations approach, for a compliance period for which allowances have not yet been recorded as detailed in section V.E of this preamble.

The agency proposes to record allowances for the mass-based trading program in accounts of affected EGUs 7 months prior to the start of each compliance period. For example, if compliance periods are 3 years long and the first compliance period comprises the years 2022, 2023, and 2024, the EPA would record allowances for 2022, 2023, and 2024 by June 1, 2021. The EPA requests comment on the proposed approach of recording allowances 7 months prior to the start of each compliance period, and on an alternative of recording allowances 13 months prior to the start of each compliance period. See section V.D.3 of this preamble for timing of recordation of allowances from the proposed set-asides.

3. Allowance Set-Asides To Address Leakage to New Sources

In addition to the general allocation method proposed above, the EPA is proposing two additional components of allowance allocation under a mass-based federal plan. These two set-asides are being proposed to satisfy the requirement in the final guidelines that mass-based plans demonstrate that they have addressed the risk of leakage to new unaffected units, as specified below.[98]

The final EGs specify the concern of leakage, which is defined in section VII.D of the final EGs preamble as the potential of an alternative form of implementation of the BSER (*e.g.,* the rate-based and mass-based state goals) to create a larger incentive for affected EGUs to shift generation to new fossil fuel-fired EGUs relative to what would occur when the implementation of the BSER took the form of standards of performance incorporating the subcategory-specific emission performance rates representing the BSER. The final EGs specified that mass-based plan approaches must address leakage, because the form of the mass goals may ultimately impact the relative incentives to generate and emit at affected EGUs as opposed to shifting generation to new sources, with potential implications for whether the mass goal implements or is consistent with the BSER and overall emissions from the sector. These circumstances are much less likely to be present under a rate-based plan approach, where the form of the goal ensures sufficient incentive to affected existing EGUs to generate and thus avoid leakage, similar to the CO_2 emission performance rates. By requiring mass-based plan components that address leakage, the final EGs ensure that mass goals are equivalent to the CO_2 emission performance rates and are thus an equivalent expression of the BSER. Section VII.D of the final EGs details the requirement for addressing leakage and why it is needed, and section VIII.J of the final EGs specifies options for mass-based state plan components that address leakage. We are proposing, as part of the mass-based approach under the federal plan and model rule, to implement allowance allocation approaches to address leakage, specifically through establishing an output-based allocation set-aside and a set-aside that encourages the installation of RE.

As noted in the EGs, if a state were to adopt allowance set-aside provisions exactly as they are outlined in this model rule once it is finalized, the requirement for that state plan to address leakage would be considered presumptively approvable.

Section VIII.J of the final EGs provides a discussion of how set-asides can effectively address leakage in a mass-based plan approach. That section of the final EGs also describes why the allowance allocation alternative for addressing leakage must be chosen for the federal plan instead of the option to regulate new non-affected fossil fuel-fired EGUs. This is because the EPA does not have authority to extend regulation of and federal enforceability to new fossil fuel-fired sources under CAA section 111(d), and therefore we cannot include new sources under a federal mass-based plan approach.

The set-asides we are proposing—described in detail below—would establish a pool of allowances that would be allocated to affected EGUS or other entities based upon criteria designed to address leakage.

These set-asides are essentially a type of ''economic incentive'' authorized by the CAA as a means of pollution prevention and control, and the expected benefits of this particular type of economic incentive to address leakage make it appropriate here.[99] The EPA believes these set-aside programs are both authorized and consistent with the purpose of the Clean Power Plan under CAA section 111(d) and the specific requirements specified in the final guidelines. They do not have the effect of increasing the stringency of the federal plan because the overall budget of allowances (representing allowable emissions) remains the same.

The EPA is aware of the successful use of set-asides and similar programs in other emissions trading programs. The following are examples of set-asides and similar programs used in other federal air quality rules.

The EPA has previously established set-asides of emissions allowances in FIPs under CAA section 110. For example, in the CSAPR, the EPA used a 5 percent set-aside for new units, because we believed it was ''important to have a small new unit set-aside in each state to cover new units within the budget that was set aside in order to address the state's significant contribution and interference with maintenance.'' (75 FR 45310; August 2, 2010). This was important, in the EPA's view, because it allowed for growth in the electric utility sector consistent with the EPA's modeling, where new units showed up in the modeling output as surrogate facilities representing potential new EGUs that come online in future years in response to demand increases or other market drivers.[100] As between a choice of requiring these new units to purchase their allowance on the open market, versus being treated in the same manner as existing—and generally understood to be less efficient and more polluting—units, *i.e.,* by being eligible to receive an initial allowance allocation out of the new unit set-aside, the EPA chose the latter.

As part of the ARP under Title IV of the 1990 CAA Amendments, Congress established a ''conservation and renewable energy reserve'' account. *See* CAA section 404(f), 42 U.S.C. 7651c(f). This is in essence a set-aside account of

[98] The EPA is also proposing a third set-aside, for a Clean Energy Incentive Program, which is detailed in section V.D.4 of this preamble, below.

[99] In designing a federal plan under CAA section 111(d), the EPA recognizes its authority as being, in some sense, the same as that available under CAA section 110(c), where the use of economic incentives is authorized. *See* CAA section 302(y), 42 U.S.C. 7602(y) (authorizing use of ''economic incentives'' in FIPs).

[100] *See also* EPA, Allowance Allocation Final Rule TSD, EPA–HQ–OAR–2009–0491, at 3–4 (June 2011).

SO_2 allowances which the regulated utilities could earn by undertaking ''qualified energy conservation measures'' and ''qualified renewable energy'' projects. The size of the reserve was set at 300,000 allowances, and utilities could earn one SO_2 allowance for every 500 MWh of energy saved through demand-side EE savings or RE generation. In the first years of the program, utilities received bonus allowances equivalent to close to 3,000 tons of avoided SO_2 emissions, while achieving co-benefits from reductions in other pollutants, and, in the words of one industry representative, ''creating a culture change where utilities are looking for opportunities everywhere.'' [101] The reserve program was nonetheless undersubscribed, and the EPA and other parties have learned from this case and made adjustments to similar programs to promote participation. This proposal seeks to minimize the administrative burden associated with participation in this rule's proposed set-asides.

In the NO_X SIP Call, the EPA encouraged states to consider including energy efficiency and renewables as a strategy in meeting their emission budgets through the use of set-asides. *See* 63 FR 57356, 57438 (October 27, 1998). A number of states created RE and demand-side EE set-asides in their SIPs in response, and later, for the implementation of CAIR. A ''roundtable'' meeting with 25 states in 2006 indicated that states that had established these programs were generally having success with them, and provided a forum for exchanges of ideas on how to handle a variety of implementation issues, such as over- and under-subscription, application issues, compliance and verification, the appropriate size of a set-aside account, how to garner public input on which projects are selected, and other issues.[102] In general, the EPA believes its experience and those of the states with these set-aside programs support the view that they are an effective means to spur clean energy projects, which in turn we believe can help to reduce the risk of leakage in this instance.[103]

Below, the EPA describes two potential allowance set-asides. First, the EPA proposes a set-aside for allowances distributed to existing NGCC units based on output (*i.e.,* output-based allocation) to mitigate emission leakage to new sources. Second, the EPA proposes a set-aside for electricity generation from qualifying renewables. This set-aside also addresses the potential for leakage to new sources, as increased RE capacity can serve electricity demand in place of new sources. The EPA also solicits comment on other set-aside options that could address leakage, including a set-aside that provides an incentive for demand-side EE. The EPA seeks comment on all aspects of the set-aside options specified in this section. This includes the inclusion of a set-aside, the method for allocation of allowances to set-asides, the size of the set-asides, the requirements for the process of distribution, eligibility requirements for receiving set-aside allowances, the proposed process for redistribution of undistributed allowances from each set-aside, and any other appropriate set-asides.

a. Set-Asides for Output-Based Allocation

The EPA is proposing a set-aside approach referred to as output-based allocation, which provides targeted allocations of a limited portion of allowances to existing NGCC units as a means of mitigating leakage. The EPA believes that this proposed set-aside would reduce incentives for generation to shift away from EGUs covered under mass-based plans to new unaffected EGUs. We seek comment on all aspects of this proposal and its underlying rationale.

Under the output-based allocation approach we are proposing, beginning with the second compliance period, a portion of the total allowances within each mass-based federal plan state would be allocated to existing NGCC units based, in part, on their level of electricity generation in the previous compliance period. Each eligible EGU would get a larger allowance allocation from this set-aside if it generates more, such that owner/operators of eligible EGUs will have an incentive to generate more in order to receive more allowances. Because the total number of allowances is limited, this allocation approach will not exceed the overall emission goal. Instead, it merely modifies the distribution of allowances in a manner designed to align the generation incentives for eligible EGUs in mass-based states with new emitting EGUs that are not subject to a mass-based limit, mitigating emissions leakage.

The EPA is inviting comment on key parameters for the appropriate design of the output-based allocation approach used for this proposed set-aside. Key parameters to be identified under the output-based allocation approach include which affected EGUs receive the allocation, the timing of the set-aside's allocation procedure, the allocation rate(s), and the size of the set-aside. The EPA also invites comment on what other parameters may be relevant for design of an appropriate output-based set-aside.

The EPA first solicits comment on which EGUs should be eligible to receive output-based allocation from the set-aside. The EPA proposes that only NGCC units subject to the final EGs receive output-based allocation from the set-aside. The EPA recognizes that performance of output-based allocation may be improved by targeting which units receive this additional incentive. In particular, this approach can most effectively address emission leakage if targeted to those affected EGUs subject to a mass goal that face the greatest difference in their incentive to generate relative to otherwise similar EGUs that are not subject to a mass goal. As noted in the discussion of the allocation rate below, new combustion turbines (*i.e.,* NGCC units and simple cycle combustion turbines) would be expected to generate more absent this set-aside. Therefore, the difference in generation incentives between affected stationary combustion turbines subject to a mass goal and otherwise similar new stationary combustion turbines that are not subject to a mass goal is likely one of the most salient deviations in production incentives to address.

The EPA also requests comment on extending output-based allocation from this set-aside to affected SGUs. Output-based allocation for SGUs may increase generation subject to the mass limit, leading to reduced generation and emissions from new emitting sources. However, the EPA does not propose this approach because it is not as effective as output-based allocation to NGCC units.

[101] U.S. EPA, Acid Rain Program, Conservation and Renewable Energy Reserve, EPA 430–R–94–010 (November 1994).

[102] U.S. EPA, State Clean Energy-Environment Technical Forum Roundtable on State NO_XAllowance EE/RE Set Aside Programs, Call Summary (June 6, 2006), available at *http://www.epa.gov/statelocalclimate/documents/pdf/summary_paper_nox_allowance_6-6-2006.pdf.*

[103] The agency has extensive experience in the design and establishment of set-aside programs. *See, e.g.,* Guidance on Establishing an Energy Efficiency and Renewable Energy (EE/RE) Set-Aside in the NO_X Budget Trading Program (March 1999), *available at http://www.epa.gov/statelocalclimate/documents/pdf/ee-re_set-asides_vol1.pdf;* Creating an EE and RE Set-aside in the NO_X Budget Trading Program: Designing the Administrative and Quantitative Elements (April 2000), available at *http://www.epa.gov/statelocalclimate/documents/pdf/ee-re_set-asides_vol2.pdf;* Creating an EE and RE Set-aside in the NO_X Budget Trading Program: Evaluation, Measurement, and Verification of Electricity Savings for Determining Emission Reductions from Energy Efficiency and Renewable Energy Actions (July 2007), available at *http://www.epa.gov/statelocalclimate/documents/pdf/ee-re_set-asides_vol3.pdf.*

This is because output-based allocation to SGUs would incentivize generation from relatively high-emitting EGUs, which would likely increase allowance prices as other emission reductions are made to respect the overarching mass limit. This approach would thus strongly counteract the intended effect of lowering the production cost from sources subject to the proposed mass-based federal plan (compared to emitting sources not subject to the plan). The EPA also requests comment on extending output-based allocation from this set-aside to zero-emitting generators (including both renewable and nuclear generation), and how the design of the OBA set-aside for such generators would differ relative to the NGCC approach (*e.g.,* the amount of allowances earned per MWh, the capacity-factor threshold, the size of the total set-aside).

The EPA also proposes that this approach be targeted towards marginal generation that may not have otherwise occurred absent this set-aside, by providing allocations under this set-aside only to eligible EGUs that exceed a 50 percent capacity factor on a net basis over the compliance period, and only for the portion of their generation that exceeds that capacity factor.[104]

The EPA also solicits comment on the timing of the output-based allocation set-aside's allocation procedure, which involves the relationship between the time at which eligible generation occurs and the vintage year(s) of the allowances allocated from this set-aside to recognize that generation. The EPA is proposing a lagged accounting procedure for this set-aside, where eligible generation that occurs during a given compliance period would receive allowances through this set-aside taken from vintage years in the subsequent compliance period. In keeping with this lagged accounting procedure, the EPA is proposing not to reserve any allowances of vintage years during the first compliance period (2022–2024) for allocation through this set-aside; eligible generation that occurs during the first compliance period would be recognized through this set-aside with allowances of vintage years from the second compliance period (2025–2027).

The EPA is proposing this lagged accounting procedure because the amount and location of eligible generation in any given compliance period remains uncertain until the compliance period has ended and the relevant data has been reported and verified. Without this lagged accounting procedure, the EPA would have to withhold an amount of allowances for this set-aside from certain vintage years even as the corresponding compliance period was already underway. Given the size of this proposed output-based allocation set-aside in certain states, the EPA believes it would be more advantageous for affected EGUs to know in advance how many allowances they will be allocated in a given period, inclusive of allowances allocated through this output-based allocation set-aside.[105]

The EPA requests comment on options for the allocation rate under this approach. The allocation rate is the number of allowances, in an amount equal to a specific amount of emissions, that the affected EGU receives per one net MWh of generation eligible for the set-aside. The EPA proposes to set the allocation rate equal to the rate-based emission standard (on a net basis) for new NGCC units under 111(b), in order to align the generation incentives across EGUs eligible for the set-aside and the type of new emitting source that would generate more absent this set-aside. Specifically, an additional MWh of eligible generation would earn the affected EGU allowances equal to the level of emissions permitted per MWh of net generation under the 111(b) new source standard, which is 1,030 lbs/MWh-net (Carbon Pollution Standards for new, modified, and reconstructed EGUs). The EPA requests comments on other values for the allocation rate. For example the allocation rate may be the expected net emissions rate of newly constructed NGCC units, the historical average emissions rate from NGCC units, or the NGCC or fossil steam source category-specific emissions performance rates promulgated in the Clean Power Plan EGs (see section VI of the final EGs).

The EPA proposes to calculate an NGCC unit's capacity factor based on the previous compliance period's net generation and the net summer capacity of the unit. The EPA is proposing to require affected EGUs to report net generation to the agency.[106] The EPA proposes to use net summer capacity as reported to EIA. In the alternative, the EPA proposes to require that NGCC units report net summer capacity directly to the EPA by adding it as a required data field in the certificate of representation that a unit's owner or operator would submit to the agency (see section V.G of this preamble). The EPA notes that the EIA net summer capacity data is reported at the generator level; if we add this data point to the certificate of representation it would be reported at the affected-EGU level, which would facilitate calculation of capacity factors. The EPA also requests comment on whether the ''maximum load value,'' which is a parameter that EGUs report to the EPA in their monitoring plans, is a reasonable proxy for EGU-level net summer capacity for these calculations. The EPA also requests comment on an alternative approach of basing the capacity-factor calculation on nameplate capacity instead of net summer capacity, or other approaches to the calculation.

The EPA proposes to determine the size of the output-based set-aside once, before the start of the program, and not to change the size thereafter. The EPA proposes to determine the size of the set-aside assuming that it would incentivize existing NGCC to increase utilization to a 60 percent capacity factor. The assumed 60 percent capacity factor offers a way to limit the size of this set-aside, which allows the remainder of the allowances in a given compliance period to be allocated through the historical-generation approach (as detailed above) and the other proposed set-asides (as detailed below). Furthermore, limiting the size of the set-aside avoids the risk of incentivizing too much generation from eligible sources, as discussed further in the Allowance Allocation Proposed Rule TSD.

The EPA proposes to determine the size of the output-based set-aside using 2012 baseline data from the Clean Power Plan EGs.[107] The EPA would calculate the size of the set-aside as 10 percent of the NGCC capacity in the state[108] multiplied by the hours in a year multiplied by the allocation rate for the set-aside. The EPA requests comment on the proposed capacity data used as the basis for determining the size of the output-based set-aside, and alternative sources of capacity data that may be used for determining its size.

[104] Effectively, the allocation rate (defined below) of output-based allocation is zero up until this average capacity factor.

[105] The EPA recognizes that under this lagged accounting procedure, if the federal plan is replaced by a state plan in a future compliance period, the incentive to create eligible generation in the last compliance period subject to the federal plan is potentially diminished.

[106] See section V.H of this preamble for proposed monitoring and reporting requirements. The EPA proposes to make the reported generation data available to the public on the agency's Web site.

[107] CO_2 Emission Performance Rate and Goal Computation TSD for the Clean Power Plan Final Rule.

[108] The sum of net summer capacity for affected NGCC units in the 2012 baseline for the Clean Power Plan EGs (CO_2 Emission Performance Rate and Goal Computation TSD for the Clean Power Plan Final Rule).

The set-asides resulting from this proposed approach are shown in Table 9 of this preamble. The set-asides in the table would apply to every compliance period except for the first compliance period for which there would be no output-based set-aside. Although the size of the set-aside would remain the same for each compliance period, as the mass goals decrease with each step in the Interim Period and to the Final Period, the set-asides would constitute an increasing share of a state's mass goal. The Allowance Allocation Proposed Rule TSD further details the proposed approach to determine the size of the set-aside. The EPA requests comment on a potential limit for the size of the set-aside in a compliance period based on a percentage of the state's total allowances for the compliance period.

TABLE 9—PROPOSED SIZE OF OUTPUT-BASED SET-ASIDE FOR THE SECOND COMPLIANCE PERIOD AND LATER

[Short tons]

State	Allowances in output-based set-aside
Alabama	4,185,496
Arizona	4,197,813
Arkansas	2,102,538
California	8,458,604
Colorado	1,348,187
Connecticut	1,090,811
Delaware	649,190
Florida	12,102,688
Georgia	3,563,104
Idaho	246,638
Illinois	1,598,615
Indiana	1,106,150
Iowa	492,510
Kansas	62,257
Kentucky	288,730
Lands of the Fort Mojave Tribe	248,127
Lands of the Navajo Nation	0
Lands of the Uintah and Ouray Reservation	0
Louisiana	2,207,879
Maine	563,925
Maryland	103,762
Massachusetts	2,439,991
Michigan	2,105,786
Minnesota	909,724
Mississippi	3,132,671
Missouri	815,210
Montana	0
Nebraska	144,635
Nevada	2,326,529
New Hampshire	542,721
New Jersey	3,413,100
New Mexico	627,085
New York	3,815,381
North Carolina	2,120,178
North Dakota	0
Ohio	1,757,326
Oklahoma	3,121,167
Oregon	1,291,027
Pennsylvania	4,392,931
Rhode Island	778,307
South Carolina	1,029,366
South Dakota	130,831
Tennessee	632,949
Texas	15,990,657
Utah	825,586
Virginia	3,011,811
Washington	1,383,060
West Virginia	0
Wisconsin	1,181,175
Wyoming	45,114

Given the proposed limit on the total size of the set-aside, and the amount of potential generation eligible for the set-aside, there may be fewer allowances available in the set-aside than can be earned at the allocation rate. The EPA proposes that, if the amount of total generation eligible for the set-aside multiplied by the allocation rate exceeds the size of this set-aside, then the allowances in this set-aside would be allocated to eligible generation on a pro-rata basis.

The EPA proposes that if the number of allowances allocated from the set-aside is less than the size of this set-aside, then the remaining allowances would be distributed to all affected EGUs using the historical-generation-based approach described above.

The EPA proposes to provide notice of the capacity and generation data used to calculate allocations from the set-aside, and the resulting allocations, by August 1 of the first year in each compliance period, *e.g.*, by August 1, 2025 for the compliance period that commences in 2025 (and based on the data from the prior compliance period). The agency proposes to provide 30 days for comment on the data and allocations, until August 31, and to provide notice of the final set-aside allocations by November 1 of the same year and record the allocations in the source accounts at that time. The EPA requests comment on other approaches to providing notice of the data and allocations.

The EPA requests comment on all aspects of the proposed approach to calculate output-based set-aside allocations. Further details are in the Allowance Allocation Proposed Rule TSD in the docket.

b. Set-Asides for Renewable Energy Projects

The EPA proposes to provide a set-aside of allowances for distribution to RE projects in each state covered by the proposed mass-based federal plan, and is also proposing this for the mass-based model rule. The agency also requests comment on whether distribution should extend to DS–EE, CHP, and other types of projects. Under this program, the EPA would reserve a percentage of each state's allowances in a set-aside account for each state. Developers of RE projects could apply to receive set-aside allowances based on the projected generation from eligible RE capacity.

This set-aside is expected to address concerns regarding leakage by lowering the marginal cost of production of the incented clean energy technologies within the state. This will make RE more competitive against new sources, reducing the potential for leakage to new sources. While the proposed set-asides would provide additional incentive for the creation of additional RE capacity, it should also be noted that the proposed mass-based trading program itself would provide incentive for new and existing low and zero-emitting generation.

In the context of the proposed federal plan, the EPA is proposing that it would create a unique set-aside for each state covered by a mass-based federal plan. Under a model rule, the state would create this set-aside. The allowances in each set-aside would be reserved from each vintage of the assigned mass goal to that state prior to allocation of allowances to sources. The EPA is proposing that 5 percent of allowances will be reserved from the allocation for each state for the purpose of the set-aside. We are also requesting comment on options for a percentage of allowances to be reserved ranging from 1 to 10 percent of total allowances in each state. The proposed percentage has been determined to provide a meaningful additional incentive for RE activities in each state, while ensuring that the vast majority of allowances are freely allocated to affected EGUs. The EPA made this conclusion based upon determining an appropriate volume of set-aside resources that, at a range of possible allowance prices, are projected to incent the development of additional RE projects. The analysis is provided in the docket as part of the Renewable Energy Set-aside TSD. We note that, under the proposed framework, these allowances would be available to affected EGUs either in the marketplace or through subsequent distribution of unclaimed set-aside allowances, and thus the provision of these set-asides does not affect the overall stringency of the program.

In section V.D.5 of this preamble, below, the EPA is proposing that the size of the RE set-asides may grow over time as certain units shift out of the program.

We are proposing, as part of the mass-based federal plan and model rule, that a project is eligible to receive set-aside allowances if it is RE that meets the eligibility requirements for rate-based ERC issuance as specified in section IV.C of this preamble and section VIII.K of the final EGs. This includes, for example, the requirement that only capacity incremental to 2012 is eligible for the set-aside. The agency requests comment on an additional potential condition that would limit eligibility to project providers that are also the owners or operators of affected EGUs. This approach has precedent in the eligibility requirements for the ARP set-aside, and would limit the entities eligible to receive set-aside allowances to those that are subject to the federal plan.

The EPA is proposing that eligible RE capacity must meet the following conditions regarding geographic eligibility for both the federal plan and model rule. Eligible RE projects must be located in the mass-based state for which the set-aside has been designated. The agency invites comment on whether capacity outside the state should be recognized, and how that could be implemented. The EPA also proposes that the generation for which an entity receives allowances from the set-aside would not be eligible for ERC issuance in rate-based states.

As specified in section IV.C of this preamble, the EPA is proposing that the same RE measures are eligible to receive set-aside allowances under a mass-based federal plan as would be eligible for ERC issuance under a rate-based federal plan and the model rule. Specifically, the following RE measures are eligible: On-shore wind, solar, geothermal power, and hydropower. The RE measure must also have the capacity to provide data quantified by a revenue-quality meter, a requirement that is further discussed in section IV.D.8 of this preamble. New nuclear units and capacity uprates at existing nuclear units are not proposed to be eligible to receive set-aside allowances. We do not think a set-aside used as an incentive for incremental nuclear capacity is a useful way to address leakage to new sources during the performance period, due to unique costs and development timelines for incremental nuclear power. All other proposed aspects of the RE eligible measure types described in section IV.C of this preamble and the requests for comment included within that section also apply in the mass-based set-aside context for both the proposed mass-based federal plan and the proposed mass-based model rule. For example, we are requesting comment on the inclusion of other RE measures, incremental nuclear, demand-side EE measures, CHP and any other emission reduction measures beyond those mentioned here, as long as they meet the eligibility requirements outlined in the final EGs for rate-based crediting, as eligible measures to receive set-aside allowances. We particularly request comment on how a set-aside to provide an incentive from these particular measures will serve to address leakage to new sources. We also request comment on the implications of the inclusion of such technologies for the streamlined implementation of projection-based EM&V requirements of the set-aside specified below in a federal plan context across the applicable jurisdictions, while still maintaining necessary rigor. We request comment on the appropriateness of the biomass treatment requirements offered for comment in section IV.C.3 of this preamble in the context of a mass-based set-aside. We request comment on requirements for the treatment of CHP and WHP, in the context of the mass-based set-aside. We also request comment on appropriate processes through which, after the federal plan is finalized, the EPA and/or stakeholders could make a demonstration of the appropriateness of new measure types and the EPA could evaluate and approve the demonstration so that a new measure type can be considered eligible for the set-aside.

To demonstrate that an RE project meets the requirements proposed above, in the context of a mass-based federal plan, it is proposed that the project proponent must provide the following: Documentation of the nature of the project and that it meets eligibility requirements, documentation that it will be located within the state in question, and a projection of expected annual MWh generation for an RE project. The EPA must approve the documentation of eligibility and the projection of MWh before the project becomes eligible for a distribution of the set-aside allowances. In addition, the proponent must register for a general account in the EPA tracking system where the allowances would be recorded. See 40 CFR 62.16320 for the requirements to establish a general account. While the EPA is proposing to allow eligible resources to use a general account to receive any allowances allocated under this section, the EPA requests comment on extending the designated representative provisions in 40 CFR 62.16290 to eligible resources instead of the general account provisions. Requiring eligible resources to submit information similar to that collected in the certificate of representation in 40 CFR 62.16305 and to appoint a designated representative to act on behalf of all owners/operators for all projects requesting allowances may improve the EM&V process by making the eligible resources more accountable. The EPA requests comment on what documentation would be required if other measure types were considered eligible to receive set-aside allowances. We propose that the same process for approval of projects be applied in a model rule, with the state taking the approving role instead of EPA.

The EM&V requirements for the mass-based set-aside differ from those for rate-based ERC issuance, particularly because it is based upon projections provided prior to generation rather than metered data provided after the generation occurs (though we are proposing that the projections will be checked against ex-post metered data). The projection method enables the distribution of set-aside allowances prior to the year during which the generation occurs. The EPA feels this still provides sufficient rigor because the set-aside does not directly affect program stringency. The reason that stringency is not affected is because of key differences between issuance of credits and distribution of set-aside allowances. Under rate-based implementation, each decision to issue an ERC based on a quantification of RE generation affects the ultimate amount of allowable CO_2 emissions, because the number of ERCs is determined by the amount of MWhs approved as eligible for ERC issuance and the ERC does not exist until the issuance decision is made. Thus the amount of ERCs that are issued can affect the stringency of the rule. As a result, the EPA has laid out specific requirements (including EM&V procedures) in the final Clean Power Plan, and in this proposed federal plan and model rule, to assure the environmental reliability of measures qualifying for ERC recognition under rate-based implementation. In contrast, any decision to recognize RE with set-aside allowance allocations under a mass-based approach does not affect the validity of the allowance itself and does not affect the CO_2 emissions outcome because the ultimate amount of allowable CO_2 emissions is determined by the total number of allowances initially created (regardless of how they are distributed). As a result, while the EPA believes it is reasonable to consider a minimum set of qualifications for recognizing RE through these allowance set-asides to assure that the RE generation that is incented is actually produced, the EPA does not believe the overall integrity of mass-based implementation is significantly affected by the robustness of whatever eligibility requirements the EPA ultimately sets for RE recognition through allocation from these set-asides. This being said, the agency is proposing to require robust demonstrations of the eligibility and EM&V projections for RE generation submitted for the set-aside, demonstrations that are based on the best practices of existing programs. This is necessary to assure the delivery of RE as a result of the set-aside.

The EPA proposes that the projections of MWh provided will be the basis of the distribution of set-aside allowances. A satisfactory demonstration of the future RE generation from an eligible project must use technically sound quantification methods that are reliable, replicable, and accompanied by underlying analytical assumptions and verifiable data sources used to demonstrate future performance. These methods, assumptions and data sources must be specified in documentation accompanying the projections. These projections and supporting documentation should all be provided in the set-aside project application, and that application must be approved by a third-party verifier. The EPA invites comment on these proposed requirements for projections. We also request comment on whether set-asides should be distributed proportional to actual MWh provided by the installation in a prior year or compliance period, or another form of historical generation data. This type of allocation method could also be similar to the structure proposed for the output-based allocation set-aside. We propose that the same projection-based distribution basis be applied in a model rule, with the state taking the approving role instead of EPA.

The EPA is proposing the following process for distribution of RE set-aside allowances. Starting prior to the compliance period, and going forward through the compliance period, RE providers in each state will have an opportunity to apply to the EPA or a designated agent to be approved as eligible to receive set-aside allowances in their state. This application must include all the requirements outlined above, including projections of expected MWh of generation. The EPA is proposing to accept RE set-aside project applications up to a deadline of June 1 in the year prior to the year during which the RE generation occurs (the ''generation year''). The EPA or its agent will review and approve the project as eligible and it will be entered into the pool of projects that will receive set-asides in any compliance period. If approved, the number of projected MWh in each generation year will be the basis of the number of allowances the provider will receive, as an input to the methodology specified below. The providers will have an opportunity to update projections for future generation years, these projections must be received by June 1 of the year prior to the generation year in question.

On December 1 of the year prior to each year of the compliance period in question, the EPA is proposing to distribute allowances from the set-aside to approved providers. The agency is proposing to distribute set-aside allowances to approved RE providers pro-rata, with the number of allowances distributed to each provider according to the percentage of total approved RE MWh for that state that the approved MWhs from their project represent. This method is proposed because it treats all eligible RE projects equally in the distribution of set-aside allowance. It also inherently provides a more significant incentive in states with less eligible RE generation, but will become less significant as RE generation increases. We also request comment on whether to restrict projects to a maximum number of allowances they can receive per MWh of generation, such as 1 allowance per MWh.

After each generation year, RE providers receiving allowances will have to provide an M&V report with the MWhs of RE generation actually produced, to assure that they have met the projected level of generation. These M&V reports need to document that the generation was by an approved project, and the report should be approved by a third party verifier. As discussed in section IV.D.8 of this preamble (EM&V section for the rate-based approach), these data should be readily available from existing metering. The EPA requests comment on the process for submitting M&V reports with actual generation.

If the project or program does not reach the MWhs projected in a particular generation year, the unfulfilled MWhs will be subtracted from that RE provider's MWhs eligible for the set-aside in the next generation year, or multiple years if the deficit exceeds the MWhs projected for the upcoming year. If this deficit is greater than 10 percent in a particular year, the provider will need to provide an explanation of the deficit and will be required to reevaluate their projections for future years. If such deficits continue through all years of the relevant compliance period, the provider will be disqualified from receiving future set-asides for the following compliance period. We also request comment on whether a provider with continuing deficits should also be disqualified from receiving ERCs for the generation in question from states with rate-based plans. The agency requests comment on all of the specified aspects of this distribution process.

The EPA is proposing that once allowances have been distributed to all approved providers, any remaining allowances in the set-aside, such as set-aside allowances designated for projects that no longer exist, will be redistributed to affected EGUs in the state in a pro rata fashion on the same distribution basis as their initial allocations were made. It is proposed that this will occur immediately after the distribution of set-aside allowances to eligible RE providers on December 1 of the year prior to the generation year in question. The EPA requests comment on this approach.

We propose that the same distribution process as outlined above be applied in a model rule, with the state taking the approving role instead of the EPA.

The EPA is also seeking comment, in the context of the proposed rate-based federal plan and model rule, on whether a portion of this set-aside should be targeted to RE projects that benefit low-income communities. This benefit could be in the form of MWh provided to the low-income community, financial proceeds from the project primarily benefiting the low-income community, or the project lowering utility costs of low-income rate-payers. The EPA seeks comment on how a low-income community should be defined as eligible under this set-aside. We seek comment on how much of the set-aside should be designated as targeted at low-income communities. We also request comment on whether the methods of approval and distribution of allowances to projects that benefit low-income communities should differ from the methods that are proposed to apply to other RE projects.

The EPA seeks comment, in the context of the proposed rate-based federal plan and model rule, on all aspects of this proposed RE allowance set-aside program, including whether it should be included as part of a mass-based federal plan, the structure of the set-aside reserve, eligibility requirements for receiving set-aside allowances, demonstration of eligibility, and the process for distribution of allowances.

4. Provisions To Encourage Early Action

For purposes of the proposed mass-based federal plan, the EPA proposes to implement the Clean Energy Incentive Program (CEIP) on behalf of a state by issuing early action allowances for eligible actions located in or benefitting the state. Eligible projects must commence construction in the case of RE or commence operations in the case of low-income EE after September 6, 2018, and will receive incentives based on the zero-emitting MWh they generate, or the energy savings they achieve, during 2020 and/or 2021.[109] These early action allowances would be drawn from a third set-aside of allowances from the general distribution methodology. The EPA believes it is reasonable to establish the total amount of the early action set-aside in an amount equal to the pool of matching allowances. Thus, the EPA proposes that the total early action set-aside would be of an amount equal to the pool of matching allowances: No more than 300 million CO_2 allowances, depending on how many states are subject to a federal plan.

The EPA proposes to distribute the 300 million early action set-aside allowances among the states based upon the amount of the reductions from 2012 levels each state must achieve relative to that of the other participating states. The EPA proposes to calculate these values as each state's proportional share of the total difference between the 2012 baseline and the 2030 mass goals.[110] See Table 10 of this preamble for the proposed set-asides for each state under the mass-based federal plan. The agency proposes to set aside 100 million early action allowances from each of the 3 years in the first compliance period (2022, 2023, and 2024) for a total of 300 million allowances to be set aside. While the table shows set-asides for every state, the EPA proposes to implement this set-aside, according to the amounts listed in Table 10, only for those states for whom the EPA is implementing the mass-based federal plan. The EPA also requests comment on other approaches for determining the size of this set-aside in the mass-based federal plan.

For the purposes of the mass-based federal plan, the EPA is proposing to award early action allowances to two types of eligible projects that are located in or benefit the state for which the EPA is implementing a federal plan:

• RE investments that generate metered MWh from any type of wind or solar resources; and
• Demand-side EE programs and measures implemented in low-income communities that result in quantified and verified electricity savings (MWh).

Eligible RE projects must commence construction, and eligible EE projects must commence implementation, after September 6, 2018 for those states on whose behalf the EPA is implementing the federal plan. These projects will receive incentives for the MWh they generate or the end-use energy demand reductions they achieve during 2020 and/or 2021.

The EPA proposes the following framework to implement the CEIP in the mass-based federal plan. First, the EPA proposes to create a set-aside of early action allowances for all federal plan states, as described above. Second, the agency proposes to create an account of ''matching'' allowances for each state participating in the CEIP—regardless of whether a state is implementing a state plan or the agency is implementing a federal plan on its behalf. This distribution would reflect each state's pro rata share of a federal pool of additional allowances—based on the amount of the reductions from 2012 levels the affected EGUs in the state are required to achieve relative to those in the other participating states[111]—which would be limited to the equivalent of 300 million short tons of CO_2 emissions. Thus, states whose EGUs have greater reduction obligations will be eligible to secure a larger proportion of the federal allocation upon demonstration of quantified and verified MWh of RE generation or demand side-EE savings from eligible projects realized in 2020 and/or 2021. The EPA intends that a portion of these matching allowances would be reserved for eligible wind and solar projects, and a portion would be reserved for eligible EE projects implemented in low-income communities. The agency recognizes that there have been historical economic, logistical and information barriers to implementing EE programs in these communities, and therefore believes it is appropriate to reserve a portion of the federal pool to incentivize investment in these programs. The EPA requests comment on the size of reserve of matching allowances for eligible low-income EE programs as well as for eligible wind and solar projects. The EPA is proposing that unused allowances in either reserve would be redistributed among participating states. This redistribution could be executed according to the pro-rata method discussed above. Alternatively, unused matching EE or RE allowances could be swept back into a federal pool and distributed to project providers on a first-come, first served basis. The EPA requests comment on these ideas as well as alternative proposals regarding the method for redistributing matching allowances, as well as the appropriate timing for such a redistribution.

Following the effective date of a federal plan for a state, the agency will create an account of matching allowances for the state that reflects the pro rata share of the 300 million short ton CO_2 emissions-equivalent matching pool that the state is eligible to receive. Any matching allowances that remain undistributed after September 6, 2018[112] will be distributed to those states with approved state plans that include requirements for CEIP participation, as well as to those states on whose behalf the EPA is implementing a federal plan. These allowances will be distributed according to the pro rata method outlined above. Unused matching allowances that remain in the accounts of states participating in the CEIP on January 1, 2023, will be retired by the EPA. The EPA seeks comment on whether the number of matching allowances available to a state under the mass-based federal plan should be limited to a number equal to the number of early action allowances included in each federal plan state's early action set-aside.

Third, for any state subject to a federal plan, the EPA proposes to award early action allowances and matching allowances to eligible projects as

[109] As discussed in section VIII.B.2 of the final emission guidelines, in the case of a state that submits a final state plan including requirements for the state's participation in the CEIP, eligible RE projects may commence construction, and eligible EE projects may commence implementation, following the date of submission of a final state plan to the EPA. These projects must be implemented in or benefit the state that submitted the final state plan to the EPA, and may receive awards for the zero-emitting MWh they generate or the end-use energy savings they achieve during 2020 and/or 2021.

[110] The 2012 baseline is from the CO_2 Emission Performance Rate and Goal Computation TSD for the Clean Power Plan Final Rule. Where a state's relative share of the reductions from 2012 levels would yield a set-aside of less than zero, the EPA proposes to assign such a state a set-aside equal to one percent of the state's 2030 mass goal and adjust the remaining state set-asides accordingly.

[111] This is the same distribution method proposed above for the allocation of early action set-aside allowances to mass-based federal plan states.

[112] This may occur because not all states may elect to include requirements for CEIP participation in their state plans.

follows, based upon the quantified and verified MWh of generation or savings achieved by the projects in 2020 and/or 2021:

- For RE projects that generate metered MWh from any type of wind or solar resources: For every two MWh generated, the project will receive a number of allowances equivalent to one MWh from the state early action allowance set-aside, and a number of matching allowances equivalent to one MWh from the EPA.
- For EE projects implemented in low-income communities: For every two MWh in end-use demand savings achieved, the project will receive a number of allowances equivalent to two MWh from the state early action allowance set-aside, and a number of matching allowances equivalent to two MWh from the EPA.

The EPA will address implementation details of the CEIP in a subsequent action. Allowances awarded by the EPA pursuant to the CEIP may be used for compliance by an affected EGU with its emission standards in any compliance period and are fully transferrable prior to such use. The EPA proposes to distribute any remaining early action set-aside allowances in a state—after distribution to all eligible projects in the state—to the affected EGUs in the state on a pro-rata basis in proportion to the initial allocations made to those EGUs under the mass-based federal plan.

As discussed in section V.E of this preamble, the EPA proposes to allow any state where a federal plan is being implemented to take responsibility for distributing allowances. This will allow a state to tailor its allowance-distribution approach to the characteristics and preferences of the state. The EPA proposes that a state that chooses to replace the federal plan allocations with a state-determined approach must include a CEIP set-aside, as authorized in section VIII.B.2 of the final EGs. The EPA intends that such a state would have the same flexibilities as a state implementing a full state plan with respect to implementation of the CEIP. That is, the state would not be required to implement a set-aside of the same size as proposed in Table 10 of this preamble, but rather could choose how many of its allowances to set-aside for the CEIP.

The EPA requests comment on all aspects of implementing the CEIP under a mass-based federal plan approach, including (1) The size of the early action allowance set-aside; (2) the approach for distributing the early action allowance set-aside among states; (3) the timing of distribution of set-aside and matching allowances; (4) the amount of allowances awarded per eligible MWh generated or avoided; (5) the criteria for eligible projects, including criteria for awards to EE projects implemented in low-income communities; (6) the mechanism for reviewing project submittals and issuing early action allowances; (7) EM&V requirements for eligible projects; and, (8) the number of early action and matching allowances that should be awarded for each ton of emissions reduced from eligible generation or low-income efficiency projects to ensure a robust response to the program. The EPA also seeks comment on how states, tribes and territories for whom goals have not yet been established in the final EGs may be able to participate in the CEIP in the future.

The EPA also requests comment on the proposed approach of requiring states to implement this program as a condition of a state choosing to determine its own allocation approach via a partial state plan or a delegation of the federal plan.

TABLE 10—PROPOSED CLEAN ENERGY INCENTIVE PROGRAM EARLY ACTION ALLOWANCE SET-ASIDE IN THE MASS-BASED FEDERAL PLAN

[Short tons]

State	Set-aside 2022 through 2024
Alabama	3,122,306
Arizona	1,719,618
Arkansas	2,187,230
California	218,846
Colorado	2,223,192
Connecticut	69,415
Delaware	138,392
Florida	3,230,248
Georgia	2,755,623
Idaho	14,929
Illinois	5,968,721
Indiana	5,754,076
Iowa	2,191,183
Kansas	2,115,630
Kentucky	4,952,862
Lands of the Fort Mojave Tribe	5,885
Lands of the Navajo Nation	1,623,066
Lands of the Uintah and Ouray Reservation	175,509
Louisiana	1,497,428
Maine	20,739
Maryland	972,775
Massachusetts	170,471
Michigan	3,727,861
Minnesota	2,002,903
Mississippi	357,307
Missouri	3,771,322
Montana	1,310,344
Nebraska	1,481,695
Nevada	336,288
New Hampshire	107,798
New Jersey	446,005
New Mexico	823,049
New York	557,771
North Carolina	2,674,590
North Dakota	2,150,635
Ohio	4,788,372
Oklahoma	2,067,006
Oregon	154,353
Pennsylvania	5,039,346
Rhode Island	35,674
South Carolina	1,652,802
South Dakota	264,207
Tennessee	2,178,084
Texas	10,400,192
Utah	1,401,189
Virginia	1,386,546
Washington	751,434
West Virginia	3,506,890
Wisconsin	2,393,870
Wyoming	3,104,324

5. Allocations to Units That Change Status

Units that retire. The EPA proposes that, if an affected EGU does not operate for 2 consecutive calendar years, the unit would continue to receive allocations for a limited number of years after it ceases operation, after which the allowances that would otherwise have been allocated to that unit would be allocated to the RE set-aside for the state in which the retired unit is located.[113] Continuing allocations to non-operating units for a period of time reduces the incentive to keep a unit operating simply to avoid losing the allowance allocations for that unit (*e.g.,* a unit that would otherwise be retired due to age and inefficiency). On the other hand, non-operating units are no longer emitting and so do not need allowances. The EPA believes that the proposed approach of allocating allowances for a specified, but limited, period after a unit ceases operating is a reasonable middle ground approach. The proposed approach also allows the RE set-asides to grow over time.

The EPA proposes to record allowances for each year of a multi-year compliance period at once, 7 months prior to the start of each compliance period, as discussed above. The agency proposes that, if an affected EGU does not operate for 2 full calendar years, then starting with the next compliance

[113] This is similar to the approach taken in CSAPR of continuing allocations to retired units for four years and then allocating the allowances to a set-aside; in CSAPR the set-aside is for new units.

period for which allowances have not yet been recorded, the allowances that would otherwise have been allocated to the unit would be allocated to the RE set-aside. As a result, the number of years of non-operation for which a retired unit would receive allocations would vary depending on when a unit retires. For example, if an affected EGU does not operate for the first two calendar years of a 3-year compliance period, then starting with the next compliance period the allowances that would otherwise have been allocated to that unit would be allocated to the RE set-aside—in other words the unit would receive allocations for 3 years of non-operation. As a further example, if an affected EGU does not operate for both calendar years of a 2-year compliance period, then starting with the compliance period after the next compliance period the allowances would be allocated to the RE set-aside—in other words the unit would receive allocations for 4 years of non-operation.

The agency requests comment on this approach for treatment of allocations to affected EGUs that retire, including on the number of years of non-operation for which a unit would continue to receive allocations. The EPA also requests comment on an alternative of distributing such allowances to the set-aside for output-based allocations, or to the remaining affected EGUs in the state in a pro-rata fashion (on the same distribution basis as the initial allocations were made), instead of allocating such allowances to the state's RE set-aside. The agency requests comment on a further alternative approach, which would be to continue allocations to the retired units. The EPA also requests comment on treatment of allocations to units that are in long-term cold storage.

Units that are modified or reconstructed. Similar to the approach for an affected EGU that retires, the EPA proposes that, if a unit is modified or reconstructed such that it is no longer an affected EGU, then starting with the next compliance period for which allowances have not yet been recorded, the allowances that would otherwise have been allocated to the unit would be allocated to the RE set-aside. The EPA requests comment on this proposed approach, including on the number of years for which a unit would continue to receive allocations. The agency also requests comment on an alternative of distributing such allowances to the set-aside for output-based allocations, or to the remaining affected EGUs in the state in a pro-rata fashion (on the same distribution basis as the initial allocations were made), instead of allocating such allowances to the state's RE set-aside. The agency requests comment on a further alternative approach, which would be to continue allocations to the modified or reconstructed units.

E. State-Determined Allowance Distribution

The EPA proposes to allow any state to replace the EPA-determined federal plan allowance-distribution provisions in the mass-based trading program with state-developed allowance-distribution provisions. In this way, a state could choose how to distribute initial allowance allocations among its affected EGUs (and other entities).

The EPA believes that this option may offer significant appeal, because it will allow a state to tailor its allocation approach to the characteristics and preferences of the state. A state would be able to design its allocation approach to address its particular state priorities, whether they are protecting low-income consumers, supporting local industries, or other goals. The EPA anticipates that a state would have great flexibility in its allowance distribution approach and could take advantage of allocation options discussed in this proposal as well as other allocation options a state might prefer. States could auction allowances and rebate the revenue to consumers, or allocate all allowances to load-serving entities, while mandating that the value be passed through to vulnerable consumers. The EPA believes that the state-determined allocation approach offers significant advantages and solicits comment on how to ease its application by states. This is similar to the approach taken in CSAPR and CAIR where the EPA adopted rules allowing states to submit SIPs with provisions replacing the allowance-distribution provisions in the CSAPR or CAIR FIPs, respectively, while remaining in the trading programs under those FIPs (76 FR 48208; August 8, 2011, 71 FR 25328; April 28, 2006). In both CSAPR and CAIR, some states have chosen to determine their own allocations under the FIPs. This form of SIP that can replace the allowance-distribution provisions in CSAPR or CAIR is termed an ''abbreviated SIP revision.'' In this proposed mass-based trading federal plan, the EPA proposes that a state may choose to submit a ''state allowance-distribution methodology'' (analogous to an abbreviated SIP revision) to replace the federal plan allowance-distribution provisions with allowance-distribution provisions of its choosing.

The mechanism the agency envisions is in the nature of a partial state plan or (for any future changes in a state's allocation methodology) a partial state plan revision. (We request comment below on the advantages and disadvantages of allowing a state to handle allocations via a delegation of federal plan authority.) In general, under the proposed approach, the procedural requirements states and the agency must follow, including public notice requirements, for the submission and approval of state plans, would be required here.

The EPA intends to provide the states with substantial flexibility in choosing approaches to distribute their allowances in a state allowance-distribution methodology. The EPA proposes that a state may choose any approach, including auctions or other methods the EPA is not proposing here, provided the state's approach addresses leakage and also implements the Clean Energy Incentive Program. The EPA is also requesting comment on any other appropriate constraints to impose on state allowance-distribution methodologies.

The Clean Power Plan EGs require mass-based state plans to include a demonstration that they have addressed the risk of leakage, and the EGs provide several options for doing so (*see* sections VII.D and VIII.J of the final EGs). One of the options provided in the EGs is to address leakage through an allowance distribution approach that provides incentive to counteract leakage. In the mass-based trading federal plan, the EPA's proposed approach to allocate allowances would address leakage using two allowance set-asides, one for output based allocation and one for RE projects, as detailed in section V.D.3 of this preamble. The EPA believes that a state allowance-distribution methodology, which would replace the federal plan allocation provisions, must also address leakage. The EPA proposes that a state allowance-distribution methodology must address leakage by providing incentive to counteract leakage, *e.g.,* by including allowance set-asides like the output-based allocation and RE set-asides detailed in section V.D.3 of this preamble, or other allocation approaches designed to counteract leakage. The EPA requests comment on this proposed approach for addressing leakage in a state allowance-distribution methodology and on any other approaches for doing so. The EGs provide an additional option for state plans to address leakage, where a state would provide a demonstration that leakage will not occur (without implementing any of the strategies specified in the EGs) due to specified characteristics of the state (section VIII.J of the final EGs). In this federal plan proposal, the EPA requests comment on an alternative option where a state that chooses to submit a state allowance-distribution methodology could provide a demonstration that leakage will not occur (without implementing the allocation strategies specified here) due to specific characteristics of the state; the EPA proposes that such demonstration must meet the requirements in the final EGs, including support by credible analysis, for such a demonstration (*see* final EGs section VII.D). The EPA notes that a state's allowance-distribution methodology may also include other set-aside approaches that are not designed to counteract leakage.

The Clean Power Plan EGs established a Clean Energy Incentive Program (section VIII of the final EGs). The EPA proposes that a state allowance-distribution methodology, which would replace the federal plan allocation provisions, must also include a Clean Energy Incentive Program, as detailed in section V.D.4 of this preamble.

Under the proposed approach of providing for states to determine their allowance distribution approaches in the federal plan mass-based trading program, the affected EGUs in a state that submitted a state allowance-distribution methodology, which the EPA approved, would participate in the federal plan mass-based trading program, but with allowance distribution determined by the state instead of by the EPA.

The EPA proposes that a state must submit to the Administrator tables specifying the unit-level allowances in an electronic format specified by the Administrator and by the specified deadlines applicable to each compliance period (*see* Table 11 of this preamble for proposed submission deadlines).

The EPA proposes that a state may submit a state allocation methodology for any compliance period, including the first compliance period, which would comprise the years 2022, 2023, and 2024. The EPA proposes that a state submitting a state allowance-distribution methodology to modify the federal plan allowance-distribution provisions must do so for all years within a compliance period (*e.g.,* for all 3 years in a 3-year compliance period).

The EPA proposes that, if the state's allowance-distribution provisions meet certain requirements and the state allowance-distribution methodology does not change any other provisions in the proposed mass-based trading program, then the agency would likely approve the state allowance-distribution methodology. In the state allowance-distribution methodology, the state could distribute allowances to affected EGUs or other entities (such as RE facilities) or could auction some or all of the allowances. The agency proposes that for EPA approval, the state allowance-distribution methodology provisions would have to meet the following requirements. The provisions would have to address leakage as discussed above. The provisions would have to provide that, for each year for which the state allowance-distribution provisions would apply, the total amount of allowances distributed could not exceed the applicable mass goal for that state for that year. A state's methodology under this proposed approach could provide that the total amount of allowances distributed is less than the applicable mass goal.[114] The EPA proposes that a state's allowance-distribution provisions would replace the EPA's allocation provisions completely—a state would not have the option of implementing only a portion of its allocations (*e.g.,* only set-asides) and having the EPA implement the remainder of its allocations. Additionally, the EPA proposes that a state allowance-distribution methodology must provide for allowances to be issued in short tons.

The allocation (or auction) of allowances would be final and could not be subject to modification. Additionally, the state's provisions could not change any other provisions of the proposed mass-based trading program with regard to the allowances (*e.g.,* the deadlines for allocation recordation, or requirements for transfer or use of allowances) or any other aspect of such trading programs.

In order for a state allowance-distribution methodology's provisions to replace the EPA's allowance-distribution provisions for a given compliance period, a state would have to submit the state allowance-distribution methodology by a deadline that would provide the agency sufficient time to review and approve it, and to submit the allowance table meeting the specified electronic format by a deadline that would provide sufficient time to record the unit-by-unit allowances in source accounts. The EPA believes that about 12 months—starting from the date of receipt of a state allowance-distribution methodology—is sufficient to complete the agency's review and approval process, which would have to provide an opportunity for public comment on the approval (or disapproval) action. Thus, the EPA proposes the following deadlines, in Table 11 of this preamble, for submission to the agency of state allowance-distribution methodologies and unit-level allowances, and for the EPA's recordation of allowances, for each compliance period. The EPA would review and approve state allowance-distribution methodologies in the 12 months between the proposed deadline for states to submit their methodologies and the proposed deadline for states to submit unit-level allowance tables. The proposed deadline for submission of allowance tables is 3 months before the proposed deadline for the agency to record allowances in source accounts. The EPA proposes to record allowances in source accounts by the recordation deadlines.

TABLE 11—PROPOSED DEADLINES FOR SUBMISSION OF STATE ALLOWANCE-DISTRIBUTION METHODOLOGIES AND UNIT-LEVEL ALLOWANCES AND FOR RECORDATION

First compliance period for which allowances would be distributed	Deadline for submittal of state allowance-distribution methodologies	Deadline for submittal of unit-level allowance table	Deadline for the EPA to record allowances
2022, 2023, 2024	March 1, 2020	March 1, 2021	June 1, 2021.
2025, 2026, 2027	March 1, 2023	March 1, 2024	June 1, 2024.
2028, 2029	March 1, 2026	March 1, 2027	June 1, 2027.
2030, 2031 *	March 1, 2028 *	March 1, 2029.*	June 1, 2029 *

* This pattern of deadlines would hold for successive 2-year compliance periods.

[114] A state allowance-distribution methodology under this proposed approach, which is analogous to an abbreviated SIP revision, could provide that the total amount of allowances distributed is less than the applicable mass goal, pursuant to the reserved authority to states to set emission standards more stringent than federal standards under CAA section 116.

The proposed deadlines for submission of state allowance-distribution methodologies are later than the state plan submission deadlines promulgated in the Clean Power Plan EGs. The agency anticipates that it can complete the approval process relatively quickly for a state allowance-distribution methodology due to its narrow scope.

The agency proposes to record the EPA-determined federal plan allocations *only* in the absence of an approved state plan or approved state allowance-distribution methodology. The EPA proposes to record in source accounts allowances that are determined by any state as soon as feasible after approval of a state allowance-distribution methodology and submission of the unit-level allowance table, and not to wait until the allowance recordation deadline to do so.

In section V.D.2 of this preamble, the EPA proposes that the allowance recordation deadline be 7 months prior to the start of the compliance period (*i.e.,* June 1 of the prior year) and also requests comment on a recordation deadline 13 months prior to the start of the compliance period (*i.e.,* December 1 of the year, 2 years before the compliance period starts). If the EPA adopted the earlier recordation deadline on which it requests comment or any other deadline, then we would adjust the deadlines for submission of state allowance-distribution methodologies and submission of unit-level allowance tables accordingly.

The EPA proposes that a state may not replace EPA-determined allocations for a compliance period for which federal plan allocations have already been recorded, for the same reasons that the agency proposes that a state may not replace a mass-based trading federal plan with a state plan for a future compliance period for which allowances have already been recorded, as discussed below in section V.F of this preamble.

The agency requests comment on the proposed approach to allow states to determine allocations via state allowance-distribution methodologies and replace the federal plan allowance-distribution provisions. The EPA requests comment on the proposed schedule for submitting state allowance distribution methodologies to the agency, for submitting the resulting unit-level allowance tables to the agency, and for the agency to record allowances. The EPA requests comment on its proposed approach of not replacing EPA-determined allocations for a compliance period for which allowances have already been recorded. The agency also requests comment on an alternative approach where a state could notify the EPA of its intent to submit a state allowance-distribution methodology in advance, in which case the agency would hold off on recording EPA-determined allocations to allow more time for state-determined allowances to be recorded, similar to the alternative timing approach discussed in section V.F of this preamble.

The EPA is also requesting comment on an alternative approach to provide the opportunity for a state to determine its allowance-distribution provisions in the federal plan mass-based trading program. The alternative approach on which the agency requests comment is to provide for a partial delegation of the federal plan—limited to the allowance-distribution provisions—to a state that wishes to determine its allowance-distribution provisions. The EPA requests comment on the relative efficiency and ease of implementation of the two approaches (the state allowance-distribution methodology described above, or the partial delegation). The agency requests comment on whether the partial delegation approach would provide sufficient flexibility for a state to choose any method to distribute its allowances including approaches that the EPA is not proposing here. See further discussion of delegations in section VI of this preamble.

F. Treatment of States Entering or Exiting the Trading Program

If the EPA implements a mass-based trading program federal plan for any state, the agency will work with a state that wishes to replace the federal plan with an approved state plan to provide a smooth transition. The EPA proposes that a mass-based trading federal plan could only be replaced by a state plan for a future compliance period for which allowances have not yet been recorded. For example, if a 3-year compliance period comprises 2022, 2023, and 2024, the EPA would record allowances in source accounts for 2022, 2023, and 2024 prior to 2022. Once 2022, 2023, and 2024 allowances had been recorded, the first compliance period for which a state could replace the federal plan with its own plan would be for the period commencing in 2025. The EPA is proposing this stipulation for the timing of replacing a federal plan with a state plan due to the need to avoid disruption to sources already subject to the mass-based trading federal plan. Without this stipulation, a state might withdraw from the mass-based trading program in the middle of a compliance period even though allowances that authorize emissions throughout that entire compliance period would already be in circulation. In that circumstance, the EPA would then need to address whether and how to remove those allowances from circulation to prevent inflation of the allowable emissions at affected EGUs in the remaining states subject to the federal plans beyond the levels specified in the Clean Power Plan EGs. The EPA believes it is more reasonable to avoid this potential disruption by requiring that the replacement of a federal plan with a state plan be scheduled to coincide with the conclusion of the last compliance period for which allowances under the federal plan have already been recorded for that state. The EPA requests comment on other approaches to provide a smooth transition from federal plan implementation to implementation by state plans, and on its proposed approach of not replacing a federal plan for any compliance period for which allowances were already recorded.

The agency requests comment on an alternative of providing for a state to give notice to the EPA of its intent to submit a state plan to replace the federal plan (or a state allowance-distribution methodology to replace federal plan allocations), and for the agency to delay recording federal plan allocations for sources in that state until a later date than proposed. The EPA requests comment on whether this alternative would help smooth the transition from federal plan implementation to state plan implementation, and on the trade-off between recording allowances in a timely way and providing this increased timing flexibility.

G. Allowance Tracking, Compliance Operations, and Penalties

The EPA proposes that the mass-based trading program use an ATCS operated essentially the same way as the existing systems that are currently in use for CSAPR and the ARP under Title IV. Under the proposed mass-based trading program, the CO_2 program would be a separate trading program maintained in the EPA's existing data system. ATCS would be used to track the trading of CO_2 allowances held by covered affected EGUs in facility level compliance accounts, as well as such allowances held by other entities or individuals. Specifically, ATCS would track the allocation of all CO_2 allowances, holdings of CO_2 allowances in compliance accounts (*i.e.,* a facility level account for all affected EGUs at the facility) and general accounts (*i.e.,* accounts for other entities such as companies and brokers), deduction of CO_2 allowances for compliance purposes, and transfers of allowances between accounts. The primary role of ATCS is to provide an efficient, automated means for affected EGUs to comply, and for the EPA to determine whether affected EGUs are complying, with the emissions limitations and any other requirements of the mass-based trading program. ATCS would also provide data to the allowance market and the public, including a record of ownership of allowances, dates of allowance allocations, allowance transfers, buyer and seller information, serial numbers of allowances transferred, emissions, and compliance information. This information would be publicly available on the EPA's Web site and in annual progress reports.

1. Designated Representatives and Alternate Designated Representatives

The EPA proposes to establish procedures for certifying and authorizing the designated representative, and alternate designated representative, of the owners and operators of an affected EGU and for changing the designated representative and alternate designated representative. The proposed provisions describe the designated representative's and alternate designated representative's responsibilities and the process through which he or she could delegate to an agent the authority to make electronic submissions to the Administrator. These provisions are patterned after the provisions concerning designated representatives and alternates in prior EPA-administered trading programs.

Under the proposed provisions, the designated representative would be the individual authorized to represent the owners and operators of each affected EGU in matters pertaining to the mass-based trading program. One alternate designated representative could also be selected to act on behalf of, and legally bind, the designated representative and thus the owners and operators. Because the actions of the designated representative and alternate would legally bind the owners and operators, the designated representative and alternate would have to submit a certificate of representation certifying that each was selected by an agreement binding on all such owners and operators and was authorized to act on their behalf.

The designated representative and alternate would be authorized upon receipt by the Administrator of the certificate of representation. This document, in a format prescribed by the Administrator, would include: Specified identifying information for the affected EGU and for the designated representative and alternate; the name of every owner and operator of the affected EGU; and certification language and signatures of the designated representative and alternate. All submissions (*e.g.,* monitoring plans, monitoring system certifications, and allowance transfers) for an affected EGU would have to be submitted, signed, and certified by the designated representative or alternate. Further, upon receipt of a complete certificate of representation, the Administrator would establish a compliance account in the ATCS for each facility with an affected EGU involved.

In order to change the designated representative or alternate, a new certificate of representation would have to be received by the Administrator. A new certificate of representation would also have to be submitted to reflect changes in the owners and operators of the affected EGU involved. However, new owners and operators would be bound by the existing certificate of representation even in the absence of such a submission.

In addition to the flexibility provided by allowing an alternate to act for the designated representative (*e.g.,* in circumstances where the designated representative might be unavailable), additional flexibility would be provided by allowing the designated representative and alternate to delegate authority to make electronic submissions on his or her behalf. The designated representative and alternate could designate agents to submit electronically certain specified documents. The previously-described requirements for designated representatives and alternates would provide regulated entities with flexibility in assigning responsibilities under the mass-based trading program, while ensuring accountability by owners and operators and simplifying the administration of the proposed mass-based trading program.

2. Allowance Tracking and Compliance System

The proposed mass-based trading program rules include procedures and requirements for using and operating the ATCS (which is the electronic data system through which the Administrator would handle allowance allocation, holding, transfer, and deduction), and for determining compliance with the allowance-holding requirements in an efficient and transparent manner. Under the proposed rules, the ATCS would also provide the allowance markets with a record of ownership of allowances, dates of allowance transfers, buyer and seller information, and the serial numbers of allowances transferred. Consistent with the approach in prior EPA-administered trading programs, allowance price information would not be included in the ATCS. The EPA's experience is that private parties (*e.g.,* brokers) are in a better position to obtain and disseminate timely, accurate allowance price information than is the EPA. For example, because not all allowance transfers are immediately reported to the Administrator for recordation, the Administrator would not be able to ensure that any reported price information associated with the transfers would reflect current market prices.

3. Compliance and General Accounts

The proposed provisions addressing compliance and general accounts describe two types of ATCS accounts: Compliance accounts, one of which the Administrator would establish for each facility with an affected EGU upon receipt of the certificate of representation for the facility; and general accounts, which could be established by any entity upon receipt by the Administrator of an application for a general account. A compliance account would be the account in which any allowances used by an affected EGU for compliance with the emissions limitations would have to be held. The designated representative and alternate for the affected EGU would also be the authorized account representative and alternate for the compliance account. Using facility-level, rather than EGU-level accounts, would provide owners and operators more flexibility in managing their allowances for compliance, without jeopardizing the environmental goals of the mass-based trading program, because the facility-level approach would avoid situations where an EGU would hold insufficient allowances and would be in violation of allowance-holding requirements even though EGUs at the same facility had more than enough allowances to meet these requirements for the entire facility. Facility-level compliance would also be consistent with other EPA-administered mass-based trading programs.

General accounts could be used by any person or group for holding or trading allowances. However, allowances could not be used for compliance with emissions limitations so long as the allowances were held in, and not properly and timely transferred out of, a general account. To open a general account, a person or group would have to submit an application for a general account, which would be similar in many ways to a certificate of representation. The application would include, in a format prescribed by the Administrator: The name and identifying information of the individual who would be the authorized account representative and of any individual who would be the alternate authorized account representative; an identifying name for the account; the names of all persons with an ownership interest with respect to allowances held in the account; and certification language and signatures of the authorized account representative and alternate. The authorized account representative and alternate would be authorized upon receipt of the application by the Administrator. The provisions for changing the authorized account representative and alternate, for changing the application to take account of changes in the persons having an ownership interest with respect to allowances, and for delegating authority to make electronic submissions would be analogous to those applicable to comparable matters for designated representatives and alternates.

4. Recordation of Allowance Allocations and Transfers

The EPA proposes to establish the following schedule and procedures for recordation of allowance allocations and transfers. By June 1, 2021, the Administrator would record allowance allocations for EGUs for 2022 through 2024. Then, by June 1 of the year prior to the beginning of each compliance period, the Administrator would record the allowance allocations for the proposed mass-based trading program for each year within that next compliance period, *e.g.,* for 2025, 2026, and 2027 by June 1, 2024. Recording these allowance allocations in advance of the first year for which they could be used for compliance would facilitate compliance planning by owners and operators and promote robust allowance markets, including futures markets for allowances.

Under the proposed provisions, the process for transferring allowances from one account to another would be quite simple. Allowances could be transferred by submitting a transfer form providing, in a format prescribed by the Administrator, the account numbers of the accounts involved, the serial numbers of the allowances involved, and the name and signature of the transferring authorized account representative or alternate. If a transfer form containing all the required information were submitted to the Administrator and, when the Administrator attempted to record the transfer, the transferor account included the allowances identified in the form, the Administrator would record the transfer by moving the allowances from the transferor account to the transferee account within 5 business days of the receipt of the transfer form.

5. Compliance With Emissions Limitations

The EPA proposes to include the following provisions regarding compliance with emission limitations. Under the proposed provisions, once the compliance period has ended (*e.g.,* at midnight on December 31, 2024 for the first compliance period), facilities with affected EGUs would have a window of opportunity following the compliance period to evaluate their reported emissions and obtain any allowances that they might need to cover their emissions during the compliance period. For example, the allowance transfer deadline for the first compliance period would be midnight on May 1, 2025 (the EPA is also requesting comment on earlier or later allowance transfer deadlines). Each allowance issued in the proposed mass-based trading program would authorize emission of one ton of CO_2 and so would be usable for compliance, for the compliance period that includes the year for which the allowance was allocated or a later compliance period. Consequently, each affected EGU would need, as of the allowance transfer deadline, to have in its facility compliance account, or to have a properly submitted transfer that would move into its compliance account, enough allowances usable for compliance to authorize its total emissions for the compliance period. The authorized account representative could identify specific allowances to be deducted, but, in the absence of such identification or in the case of a partial identification, the Administrator would deduct on a first-in, first-out basis. Deducting allowances may have tax and accounting implications, so having a default deduction method provides the representatives with certainty regarding which allowances will be deducted for compliance. Allowances that are deducted for compliance will remain in the system in an EPA account, which ensures they will not be used again. If a facility were to fail to hold sufficient allowances for compliance by all affected EGUs at the facility, then the owners and operators of the facility and each affected EGU at the facility would have to provide, for deduction by the Administrator, two allowances allocated for the compliance period in the next year for every allowance that the owners and operators failed to hold as required to cover emissions. This submittal of two times the allowances required for the prior period is an ongoing obligation until compliance is achieved, and there is an ongoing obligation to comply in the current period. In addition, these owners and operators would be subject to civil penalties for each violation in accordance with the CAA, with each ton of unauthorized emissions and each day of the compliance period involved constituting a violation of the CAA.

The EPA believes that it is important to include a requirement for an automatic deduction of allowances. The deduction of one allowance per allowance that the owners and operators failed to hold would offset this failure. The automatic deduction of another allowance per allowance that the owners and operators failed to hold that could not be avoided, regardless of any explanation provided by the owners and operators for their failure, would provide a strong incentive for compliance with the allowance-holding requirement by ensuring that non-compliance would be a significantly more expensive option than compliance. Such automatic deductions have been successfully used in prior programs including the CAIR, achieving compliance rates close to 100 percent.

6. Other Allowance Tracking and Compliance Operations Provisions

The proposed provisions regarding allowance tracking and compliance also provide that the Administrator could, at his or her discretion and on his or her own motion, correct any type of error that he or she finds in an account in the ATCS. In addition, the Administrator could review any submission under the mass-based trading program, make adjustments to the information in the submission, and deduct or transfer allowances based on such adjusted information. These provisions are a standard part of other trading programs administered by the EPA including the ARP and Cross State Air Pollution Rule (*see* 40 CFR 72.96, 73.37, 97.427, and 97.428).

H. Emissions Monitoring and Reporting Requirements

The EPA proposes that units subject to the mass-based federal plan trading program would monitor and report CO_2 mass emissions in accordance with 40 CFR part 75.

The EPA is proposing to require affected EGUs in all states covered by the mass-based federal plan trading program to monitor and report CO_2 emissions and output data by January 1, 2022. Quarterly reporting would be required, with each quarterly report due to the Administrator 30 days after the last day in the quarter. The reporting would be in accordance with 40 CFR 75.60. The use of 40 CFR part 75 certified monitoring methodologies would be required. Many EGUs that might be covered by the proposed federal plans will generally have no changes to their monitoring and reporting requirements and will continue to monitor and submit reports under 40 CFR part 75 as they have under existing programs. The EPA anticipates fewer than 50 affected EGUs that would not otherwise be subject to the ARP will have to purchase and install additional CEMS and data handling systems or upgrade existing equipment in order to meet the monitoring and reporting requirements of this program (the EPA anticipates approximately 10 coal fired units and approximately 40 gas and oil fired units will qualify for an excepted monitoring methodology). Several of the units not otherwise subject to the ARP are subject to the MATS program and, therefore, will have already installed stack flow rate and/or CO_2 monitors necessary to comply with this rule in order to comply with the MATS. The CEMS used to comply and report data for MATS will be used for this rule to generate and report CO_2 emissions data without having to install duplicative monitors. The same CO_2 and stack gas flow rate monitored data used in conjunction with mercury and other CEMS to calculate a toxic pollutant emission rate may be used to calculate a CO_2 mass or CO_2 emission rate for this program. RGGI, ARP, MATS and this rule all refer to CEMS installed and certified in accordance with 40 CFR part 75. RGGI and ARP currently require the reporting of CO_2 mass emissions on an hourly basis and cumulative totals at the end of each calendar quarter. The same monitors and data collected may be used for multiple purposes for RGGI, ARP, MATS and this rule. Relying on the same monitors that are certified and quality ensured in accordance with 40 CFR part 75 ensures cost efficient, consistent, and accurate data that may be used for different purposes for multiple regulatory programs.

The majority of the units covered by this rule are already affected by the Acid Rain and/or RGGI programs and will have minimal additional monitoring and reporting requirements.

The EPA also requests comment on requiring monitoring and reporting of CO_2 mass and net generation for the year before the initial compliance period begins, *i.e.,* to commence January 1, 2021. Only the monitoring and reporting would be required in 2021—compliance with the requirement to hold allowances would commence on the compliance period schedule that is detailed in section V.C of this preamble.

VI. Implementation of the Federal Plan and Delegation

Under section 111(d) of the CAA, the EPA adopts EGs that are then implemented when the EPA approves a state or tribal [115] plan or promulgates a federal plan that implements and enforces the EGs for affected EGUs in states or areas of Indian country [116] without an approved state or tribal plan. Congress has determined that the primary responsibility for air pollution prevention and control rests with state and local agencies, while also recognizing that federal leadership is essential for the development of cooperative federal, state, regional, and local programs to prevent and control air pollution. *See* CAA section 101(a)(3) and (4). Congress has also provided for Indian Tribes meeting specified eligibility criteria to implement the CAA within the exterior boundaries of their reservations or other areas within the tribe's jurisdiction. *See* CAA section 301(d)(1) and (2). Even in the event that it becomes necessary for the EPA to directly regulate affected EGUs under CAA section 111(d), states and eligible tribes may still seek a delegation of authority from the EPA to implement a federal plan, similar to the ability to take delegated authority under other CAA programs. The EPA encourages states and eligible tribes that do not submit approvable plans to request delegation of the federal plan if they wish to have primary responsibility for implementing the EGs. Approved and effective state or tribal plans or delegation of the federal plan is the EPA's preferred outcome in many circumstances where the EPA believes that state and local, or tribal, agencies have practical knowledge and enforcement resources critical to achieving the highest rate of compliance. Delegation of a standard or requirement generally means that obligations a source may have to the EPA under a federally promulgated standard become obligations to a state or tribe in the first instance (except for functions that the EPA retains for itself) upon delegation.[117] [118]

A. Delegation of the Federal Plan and Retained Authorities

If a state or tribe [119] intends to take delegation of the federal plan, the state or tribe should submit to the appropriate EPA Regional Office a written request for delegation of authority. The state or tribe should explain how it meets the criteria for delegation. These criteria are explainedgenerally in the ''Good Practices Manual for Delegation of NSPS and NESHAP'' (EPA, February 1983). The letter requesting delegation of authority to implement the federal plan should: (1) Demonstrate that the state or tribe has adequate resources, as well as the legal and enforcement authority to administer and enforce the program; (2) include an inventory of affected EGUs, which includes those that have ceased operation but have not been dismantled, an inventory of the affected units' air emissions, and a provision for state or tribal progress reports to the EPA; (3) certify that a public hearing has been held on the state or tribal delegation request; and (4) include a memorandum of agreement between the state or tribe and the EPA that sets forth the terms and conditions of the delegation, the effective date of the agreement and the mechanism to transfer authority. Upon signature of the agreement, the appropriate EPA Regional Office would publish an approval documentin the **Federal Register**, thereby incorporating the delegation of authority into the appropriate subpart of 40 CFR part 62. *See also* EPA's Delegations Manual, Delegation 7–139, ''Implementation and Enforcement of 111(d)(2) and 111(d)(2)/129(b)(3) federal plans.'' (A copy of this delegation has been placed in the docket for this action.)

If authority is not delegated to a state or tribe, the EPA will implement the federal plan. Also, if a state or tribe fails to properly implement a delegated portion of the federal plan, the EPA will assume direct implementation and

[115] As discussed in section VI.D of this preamble, tribes with affected EGUs in their areas of Indian country can apply for TAS for the purpose of developing and seeking EPA approval of a tribal implementation plan (TIP) implementing the EG, but are not required to do so.

[116] As discussed in section VI.D of this preamble, in adopting a federal plan implementing the EGs in areas of Indian country containing affected EGUs, the EPA must determine that such a plan is ''necessary or appropriate'' to protect air quality. *See* 40 CFR 49.11(a).

[117] If the Administrator chooses to retain certain authorities under a standard, those authorities cannot be delegated, *e.g.,* the authority to allow alternative methods of demonstrating compliance.

[118] We note that issuance of a title V permit is not equivalent to the approval of a state plan or delegation of a federal plan. This has been discussed in prior rulemakings, *see, e.g.,* Proposed Federal Plan for Commercial Industrial Solid Waste Incinerators (CISWI) (67 FR 70640, 70652; November 25, 2002); Final Federal Plan for CISWI (68 FR 57518, 57535; October 3, 2003).

[119] A tribe interested in taking delegation of the federal plan must also apply, and be approved by the EPA, for TAS eligibility for that purpose. *See* 40 CFR part 49.

enforcement of that portion. The EPA will continue to hold inspection, information gathering, enforcement, and other parallel authorities along with the state or tribe even when a state or tribe has received delegation of the federal plan. In all cases where the federal plan is delegated, the EPA may retain and not transfer authority to a state or tribe to approve certain items promulgated in the 2015 CAA section 111(d) Clean Power Plan.

This proposed federal plan also specifies that EGU owners or operators who wish to petition the agency for any alternative requirement should submit a request to the Regional Administrator with a copy sent to the appropriate state.

B. Mechanisms for Transferring Authority

There are two mechanisms for transferring implementation authority to state and local agencies and tribes: (1) EPA approval of a state or tribal plan after the federal plan is in effect; and (2) if a state or tribe does not submit or obtain approval of its own plan, EPA delegation to a state or tribe of the authority to implement certain portions of this federal plan to the extent appropriate and if allowed by state or tribal law. Both of these options are described in more detail below.

1. Federal Plan Becomes Effective Prior To Approval of a State or Tribal Plan

After EGUs in a state or area of Indian country become subject to the federal plan, the state or local agency or tribe may still adopt and submit a plan to the EPA. If the EPA determines that the state or tribal plan is satisfactory and approvable pursuant to the EGs, the EPA will approve the state or tribal plan. If the EPA, on review of the submitted state or tribal plan, determines that this is not the case, the EPA will disapprove the plan and the EGUs covered in the state or tribal plan would remain subject to the federal plan until a state or tribal plan covering those EGUs is approved and effective. Prior to disapproval, the EPA will work with states and eligible tribes to attempt to reconcile areas of the plan that are unapprovable.

Upon the effective date of an approved state or tribal plan, the federal plan would no longer apply to EGUs covered by such a plan and the state or local agency, or the tribe, would implement and enforce the state or tribal plan in lieu of the federal plan. The timing of effectiveness of an approved state or tribal plan in this circumstance may depend in part on the need to ensure a smooth transition and maintain regulatory certainty. Thus, for example, under a mass-based federal plan, we propose to handle these transitions so that they coincide with the compliance periods. The approval of a state or tribal plan would also involve a public comment process, which would give interested stakeholders including any affected EGUs, the opportunity to comment. This will assist in ensuring that compliance, program integrity, electric reliability, and other critical factors are maintained. When an EPA Regional Office approves a state or tribal plan, it will amend the appropriate subpart of 40 CFR part 62 or 40 CFR part 49, respectively, to indicate such approval, as well as the timing of its effectiveness.

As discussed elsewhere in this document, the EPA may also in certain circumstances approve a partial state or tribal plan (sometimes called an ''abbreviated state plan'') that may modify certain limited provisions in the federal plan trading program. For example, this could occur if a state or tribe wishes to handle the initial allocation of allowances in a mass-based trading program, as discussed in section V.E of this preamble. The partial state or tribal plan would allow for the state or tribe to assume direct authority for administering and implementing this aspect of the trading program, while the remainder of the federal plan remains in place. The procedural and submission requirements set forth in the framework regulations of 40 CFR part 60, subpart B and the EGs would generally apply to a partial state or tribal plan, just as they would a full state or tribal plan. The scope of the requirement, however, would be commensurate with the scope of the partial plan. For instance, if a state or tribe seeks approval of a partial plan solely to handle allowance allocations, then the required statement of legal authority would be limited to those legal authorities the state or tribe must have to implement and enforce this component of the trading program.

2. State or Tribe Takes Delegation of the Federal Plan

The EPA, in its discretion, may delegate to state or tribal air agencies the authority to implement this federal plan. As discussed above, the EPA believes that it is advantageous and the best use of resources for state or local agencies or tribes to agree to undertake, on the EPA's behalf, administrative and substantive roles in implementing the federal plan to the extent appropriate and where authorized by state or tribal law. If a state or tribe requests delegation, the EPA will generally delegate the entire federal plan to the state or tribal agency, thereby providing authority to the state or tribe for things such as administration and oversight of compliance reporting and recordkeeping requirements, inspections of its affected EGUs, and enforcement. The EPA will continue to hold inspection, information gathering, enforcement, and other authorities along with the state or tribe even when a state or tribe has received delegation of the federal plan. The delegation will not include any authorities retained by the EPA.

C. Implementing Authority

The EPA Regional Administrators have been delegated the authority for implementing the federal plan. All reports required by the federal plan should be submitted to the appropriate Regional Administrator. Section II.B of this preamble includes Table 2 that lists names and addresses of the EPA Regional Office contacts and the states they cover.

With respect to the administration of a federal trading program in any final federal plan for a state or tribe, group of states or combined group of states and tribes, the Office of Air and Radiation within the Headquarters of the EPA is proposed to be the primary office within the agency with delegated CAA section 111(d)(2) authority. *See* Delegation 7–139, section 3(c).

D. Necessary or Appropriate Finding for Affected EGUs in Indian Country

Indian Tribes may, but are not required to, submit tribal plans to implement the EGs. Section 301(d) of the CAA and 40 CFR part 49 authorize the Administrator to treat an Indian Tribe in the same manner as a state (*i.e.,* TAS) for purposes of developing and implementing a tribal plan implementing the EGs. *See* 40 CFR 49.3; *see also* ''Indian Tribes: Air Quality Planning and Management,'' hereafter ''Tribal Authority Rule,'' (63 FR 7254, February 12, 1998). We invite tribes with EGU in their area of Indian country to comment on the level of their interest, if any, in developing their own plans.

The EPA is proposing in this action to find that it is necessary or appropriate to regulate affected EGUs in each of the three areas of Indian country that have affected EGUs under the proposed federal plan. The EPA is authorized to directly implement the EGs in Indian country when it finds, consistent with the authority of CAA section 301 which the EPA has exercised in 40 CFR 49.11, that it is necessary or appropriate to do so. In the final EGs, the EPA establishes emission performance rates for the four EGUs located in Indian country and mass- and rate-based emission goals for each of the three affected areas of Indian country. These areas include lands of the Navajo Nation's reservation, lands of the Ute Tribe of the Uintah and Ouray Reservation, and lands of the Fort Mojave Tribe's reservation. The EPA proposed carbon pollution EGs for EGUs in these areas and U.S. Territories in a Supplemental Notice of Proposed Rulemaking. *See* 79 FR 65482 (November 4, 2014). The four facilities with affected EGUs located in Indian country that the EPA identified in the Supplemental Notice are: The South Point Energy Center, on the Fort Mojave Reservation geographically located within Arizona; the Navajo Generating Station, on the Navajo Indian Reservation geographically located within Arizona; the Four Corners Power Plant, on the Navajo Indian Reservation geographically located within New Mexico; and the Bonanza Power Plant, on the Uintah and Ouray Indian Reservation geographically located within Utah. The emission performance targets for these areas were finalized along with those for EGUs located in the rest of the country in the final EGs.

In this action, we are proposing to find that it is necessary or appropriate, in each of the three areas of Indian country that have affected EGUs, to establish a federal plan that applies to the four power plants located on the Navajo Nation, the Fort Mojave Indian Reservation, and the Uintah and Ouray Reservation of the Ute Tribe. The affected EGUs located on the Navajo Nation are in an area of Indian country located within the continental United States, are interconnected with the western electricity grid, and are owned and operated by entities that generate and provide electricity to customers in several states. The affected EGU located on the Uintah and Ouray Reservation of the Ute Tribe is in an area of Indian country located within the continental United States, is interconnected with the western electricity grid, and is owned and operated by an entity that generates and provides electricity to customers in several states. The affected EGU located on the Fort Mojave Indian Reservation is in an area of Indian country located within the continental United States, is interconnected with the western electricity grid, and is owned and operated by an entity that generates and provides electricity to customers in several states. To date, none of the three tribes on whose areas of Indian country the four power plants are located have expressed a clear intent to develop and seek approval of a tribal implementation plan. Thus, absent a federal plan, the significant emissions from these four power plants could go unregulated by the Clean Power Plan.

Because the agency has finalized emission performance targets for these power plants in the EGs, there is, in our view, little benefit to be had by not proposing to include them in a federal plan now and a potentially significant downside to not doing so; the reductions the EPA has determined are achievable in the EGs would become more difficult and costly for these power plants to achieve if they are delayed in entering into the trading program the agency intends to establish. In order to meet the performance targets, we are anticipating that the affected EGUs may need to secure allowances or ERCs (depending on the approach ultimately finalized) during the compliance periods. They may also be able to generate and sell compliance instruments by participating in the trading program. Thus, proposing a finding that it is necessary or appropriate to establish one or more federal plans providing the ability to participate in a rate- or mass-based trading program is in the interest of these four power plants located in areas of Indian country. We believe that this together with the facts that, as indicated above, all four EGU are interconnected with the western electricity grid and are owned and operated by an entity that generates and provides electricity to customers in several states thereby making it potentially disruptive and inequitable not to include them in one or more federal plans on the same schedule as other affected EGU strongly supports proposing to find that it is necessary or appropriate to establish one or more applicable federal plans at this time.

We recognize that the governments of these tribes may still choose to seek TAS to develop a tribal plan, and this proposed determination does not preclude the tribes from taking such actions. We also note that this proposed determination does not preclude these tribes from seeking TAS and receiving delegation to administer aspects of any applicable federal plan that is ultimately promulgated. In the event a federal plan is needed, proposing a necessary or appropriate finding at this time will allow the EPA to expeditiously promulgate a final federal plan for one or all of these power plants in the future to allow trading to occur. We will continue to consult with the governments of the Navajo Nation, Fort Mojave Indian Tribe, and the Ute Tribe of the Uintah and Ouray Reservation during the comment period for this proposal, and prior to taking any action to finalize a necessary or appropriate finding and/or a federal plan. Comments on the appropriateness of the proposed finding should be submitted within the comment period specified in the **DATES** section of this preamble.

VII. Amendments To Process for Submittal and Approval of State Plans and EPA Actions

As indicated in the final rulemaking action for the CAA section 111(d) guideline, ''Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units,'' in this action, in addition to the proposed federal plans and model trading rules, the EPA is also proposing to amend the framework regulations and update the process for acting on CAA section 111(d) state plans under 40 CFR part 60, subpart B. These changes would be applicable to any future CAA section 111(d) rules going forward, not just the Clean Power Plan EGs. The EPA proposes six changes to the CAA section 111(d) process in the framework regulations to include: (1) Partial approval/disapproval mechanisms similar to CAA section 110(k)(3); (2) a conditional approval mechanism similar to CAA section 110(k)(4); (3) a mechanism for the EPA to make calls for plan revisions similar to the ''SIP-call'' provisions of CAA section 110(k)(5); (4) an error correction mechanism similar to CAA section 110(k)(6); (5) completeness criteria and a process for determining completeness of state plans and submittals similar to CAA section 110(k)(1) and (2); and (6) updates to the deadlines for the EPA action. In addition, in this section, the agency is proposing an interpretation regarding the effect under section 111 if an existing facility subject to CAA section 111(d) modifies or reconstructs. We believe these changes will significantly streamline the state plan review and approval process, be more respectful of state processes, and generally enhance the administration of the CAA section 111(d) program.

CAA section 111(d)(1) provides that the EPA ''shall establish a procedure similar to that provided by CAA section [110] of this title under which each state shall submit to the Administrator a [111(d)] plan. . . .'' 42 U.S.C. 7411(d)(1). Thus, the CAA directs the EPA to look to the structure of the SIP program when designing the procedures the states and agency will use to develop CAA section 111(d) plans. Notably, the CAA does not require the CAA section 111(d) procedures to be identical to those the EPA uses under

CAA section 110 for SIPs.[120] Therefore, the EPA interprets CAA section 111(d) to provide the EPA flexibility in designing procedures that reflect the structure of those used under CAA section 110 for implementation plans, without requiring the EPA to exactly track SIP procedures when acting on section 111(d) plans.

As a general matter these proposed changes would simply update the CAA section 111(d) framework regulations to include several new, more flexible procedural tools that Congress introduced into section 110 in the 1990 CAA Amendments. The basic procedures in the CAA section 111(d) framework regulations were promulgated in 1975 based on the structure of CAA section 110 as Congress designed it in the 1970 CAA. *See* 40 FR 53340–49 (November 17, 1975). Over the years since 1970, the EPA and the states learned a great deal about the procedural limitations of the original SIP review process. The 1970 CAA only allowed the EPA two choices—to approve or disapprove SIP submittals. The agency struggled to deal responsively to situations where the EPA wanted to work with states to get state programs approved to the extent possible, while maintaining consistency with CAA requirements. Congress responded in 1990 and enhanced the procedural mechanisms the EPA has to act on SIPs. The EPA is proposing correspondingly to update the CAA section 111(d) regulations in a similar fashion. Currently, the EPA's framework regulations for submittal and adoption of CAA section 111(d) state plans do not explicitly provide for the EPA to use some of the same procedures for approving or disapproving state plans Congress introduced into the SIP program in the 1990 CAA Amendments. The EPA is proposing to amend the procedures for approval or disapproval of CAA section 111(d) state plans to reflect the enhancements Congress included in CAA section 110 for agency actions on SIPs. These proposed amendments are discussed in more detail below.

A. Partial Approvals/Disapprovals

First, the EPA proposes to add authority similar to that under CAA section 110(k)(3) to partially approve or disapprove a plan.[121] This is a particularly useful function when much of a state plan is approvable and the EPA and the state cannot reach resolution on only a small, severable portion of the state plan. In this case, the EPA prefers not to be in a position where it must disapprove the full plan, but rather to allow the state to move forward with those portions of the plan that are approvable. This approach would also address those situations where the state wishes to take over a discrete part of a federal plan. For instance, in this proposal, states will be able to seek approval of a partial state plan that will give them the ability to handle the allocation of allowances under a mass-based federal plan.

In cases where elements of a plan are functionally severable from each other, and one element is approvable while another is not, this provision will authorize the EPA to approve one part of a plan and disapprove the other. It will also authorize the EPA to accept and review a state plan that is only partial in nature, if identified by the state as such, so long as the other applicable submission requirements are met (such as demonstration of legal authority and completion of the public process). When the state submits what it intends to be a full state plan (rather than just a partial plan), the EPA proposes that the approvable portion of a plan must be functionally severable from the rest of the plan. This will be the case when the following conditions are met. First, the approvable portion of the plan must not depend on the rest of the plan. In other words, the disapproval of the remaining portion of the plan must not affect the portion that is approved. Second, approval of the approvable portion must not alter the function of the submittal in a way that is contrary to the state's intent.

The partial disapproval would be a disapproval for the purposes of CAA section 111(d)(2)(A) and would trigger the EPA's authority to issue a federal plan for the state, at least for that part of the plan that was disapproved. Incorporating this mechanism under the framework regulations for CAA section 111(d) will enable the EPA to approve a state to implement as much of its program as is consistent with a CAA section 111(d) guideline and may reduce the scope of any federal plan that would be necessary.

B. Conditional Approvals

The second mechanism is the authority under CAA section 110(k)(4) to conditionally approve a plan. Where a state has submitted a plan that substantially meets the requirements of a CAA section 111(d) emission guideline, but requires some specific amendments to make it fully approvable, this provision authorizes the EPA to conditionally approve the plan. The Governor or his/her designee must submit to the EPA a commitment that specifies the amendments to be adopted and submitted to the EPA by no later than 1 year from the effective date of the conditional approval. If the state fails to meet its commitment, the conditional approval is treated as a disapproval. Incorporating this mechanism under the framework regulations for CAA section 111(d) will enable the EPA to approve a state to begin to administer a substantially complete program that requires only specific changes to be fully approvable. This provision is designed to authorize a state with a substantially complete and approvable program to begin implementing it, while promptly amending the program to ensure it fully complies with CAA section 111(d).

C. Calls for Plan Revisions

CAA section 110(k)(5) authorizes the EPA to find that a SIP does not comply with the requirements of the CAA. To date, the EPA has not considered using a similar procedure pursuant to the authority under CAA section 111(d). We now propose to do so. The ability to call for plan revisions is fundamental to a program that will be implemented over many years or multiple decades. Under the Clean Power Plan EGs, states have more than a decade to fully implement emissions standards or state measures in order to ensure affected EGUs achieve the emission goals of the EGs. Throughout this period, the EPA and the states will be monitoring their programs to ensure they are achieving the intended results. It is possible that design assumptions about the effect of control measures the states incorporate into their plans could prove inaccurate in retrospect and could result over time in the plan not meeting the emission reductions required by the EGs. In that case, having a procedural mechanism available under CAA section 111(d) similar to the so-called ''SIP call'' mechanism in CAA section 110(k)(5) will allow the agency to initiate a process with the state to make necessary

[120] *See* Webster's II New Riverside University Dictionary (Riverside 1988) (defining ''similar'' to mean ''resembling though not completely identical'').

[121] We recognize that the regulations appear to already contemplate partial approval/disapprovals to some extent. *See* 40 CFR 60.27(a) (''The Administrator may . . . extend the period for submission of any plan . . . or *portion* thereof.'') (emphasis added). We note that this language only allows for extensions of time with respect to portions of state plan submissions and may not sufficiently authorize a permanent partial approval. The proposed enhancement will resolve any ambiguity that partial approvals/disapprovals are an acceptable mechanism under CAA section 111(d).

revisions to ensure the plan functions properly.

Accordingly, the EPA is proposing to amend the framework regulations to include a provision similar to CAA section 110(k)(5) under which the EPA may find that a state's CAA section 111(d) plan is substantially inadequate to comply with the requirements of the CAA and require the state to revise the plan as necessary to correct such inadequacies. Consistent with CAA section 110(k)(5), the EPA shall notify the state of any inadequacies and establish a reasonable deadline for the state to submit required plan revisions. That deadline will not exceed 18 months after the date of the action. The EPA will make its finding and notice to the state available to the public.[122]

The effect of such a finding is that either the state submits the program corrections by the date the EPA sets in the document, or pursuant to CAA section 111(d)(2)(A), the EPA has authority to issue a federal plan for a state that misses its deadline to correct its plan. In effect, the finding of plan inadequacy establishes a plan submittal deadline subject to the provisions of CAA section 111(d)(2)(A). A finding of failure to meet that new deadline triggers the EPA's authority to issue a federal plan for the state. The EPA may promulgate a federal plan at any time following the state's failure to timely submit an adequate plan that addresses the EPA's finding.

While these authorities are important, the intention of having a mechanism to call for plan revisions is to have a way to initiate an orderly process to improve plans when they are not meeting program objectives. It is the EPA's hope that a call for plan revision leads to a constructive dialogue with a state or states, and ultimately, an improved and more effective CAA section 111(d) plan.

The EPA is also proposing that the agency can call for a plan revision in circumstances where a state is not implementing its approved state plan and, therefore, the state plan is substantially inadequate to provide for the implementation of CAA section 111(d) standards of performance. As discussed above, the CAA directs the EPA to develop a procedure for state plans under CAA section 111(d) similar to CAA section 110 SIP procedures. Calling a plan that is substantially inadequate to provide for implementation of standards of performance (*i.e.,* there is a failure to implement a state plan) is one area where the EPA proposes it is appropriate to adapt the procedural mechanisms available in the SIP program to provide a similar process that assures effective state plan implementation under CAA section 111(d). Under CAA section 110(k)(5), the EPA may call for a revision of a state plan ''[w]henever the Administrator finds that the . . . plan . . . is substantially inadequate to . . . comply with any requirement of [the Act].'' If the state does not submit a plan revision in response to the call to cure the failure to provide for implementation, the EPA would have the authority to promulgate the federal plan being proposed.

One critical requirement of CAA section 111(d)(1)(B) is that a state must submit a plan that ''provides for the *implementation and enforcement* of such standards of performance'' (emphasis added). If, after the EPA has approved a plan, a state fails to implement that plan, the plan has become substantially inadequate to comply with this requirement of the CAA. Under this proposal, the EPA's remedy would be to find the plan is substantially inadequate, which triggers the state's obligation to cure, and failing that, the EPA's authority to promulgate the federal plan.

In the alternative, the EPA proposes that this authority to call a plan for failure to implement is anchored in the authority provided under CAA section 110(k)(5) to call a SIP when the agency finds that it is ''substantially inadequate to attain or maintain the relevant national ambient air quality standard.'' In the context of CAA section 111, this authority translates into the EPA calling a state plan when the agency finds that it is substantially inadequate to achieve the emission reductions required under the EGs. If a state has failed to implement its plan, and that failure is pervasive enough to render the requirements of the plan ineffective, it is reasonable for the EPA to find that the state plan is substantially inadequate to achieve the emission reductions required under the EGs. The state's failure to implement has revised the effect of the plan so that it is no longer adequate to meet the CAA's requirements.

D. Error Corrections

The fourth mechanism is the error correction authority under CAA section 110(k)(6). Where the EPA concludes that it has erroneously approved, disapproved, or promulgated a plan or plan revision (or part thereof), this section authorizes the agency to revise its action, in the same manner as the original action, without requiring any further submission from the state. Prior to the 1990 CAA Amendments, there was some question whether the EPA could unilaterally correct a previous action on a SIP submittal without the state having to submit a new SIP. This limitation imposed unnecessary burdens on states to fix even obvious errors, because CAA section 110(a)(2) requires the state to provide notice and a public hearing on each new SIP submittal. Incorporating this mechanism into the CAA section 111(d) framework regulations will allow the EPA to fix errors in its prior actions on state plans without imposing on the states the corresponding burden of providing notice and a public hearing as required under the CAA section 111(d) framework regulations. *See* 40 CFR 60.23.

E. Completeness Criteria

Completeness criteria provide the agency with a means to determine whether a submission by a state includes the minimum elements that must be met before the EPA is required to act on such submission. When submittals do not contain the necessary minimum elements, then the EPA may, without further action, find that a state has failed to submit a plan. This determination is ministerial in nature and requires no exercise of discretion or judgment on the agency's part, nor does it reflect a judgment on the sufficiency or adequacy of the submitted portions of a state plan. The task is accomplished by simply comparing the materials provided by the state as its submittal against the required criteria to determine whether the plan is complete or not. In the case of SIPs under CAA section 110(k)(1), the EPA promulgated completeness criteria in 1990 at Appendix V to 40 CFR part 51 (55 FR 5830; February 16, 1990). The EPA proposes to adopt criteria similar to the criteria set out at section 2.0 of Appendix V for determining the completeness of submissions under CAA section 111(d). The completeness criteria can be grouped into: (1) Administrative materials; and (2) technical support. The EPA proposes that both groups would apply to all CAA section 111(d) rules going forward. The agency notes that the addition of completeness criteria in the framework regulations does not alter any of the submission requirements states already have under the EGs.

For administrative materials, the EPA is proposing completeness criteria that mirror the existing administrative criteria for SIP submittals because the two programs have similar

[122] Consistent with the agency's practice under CAA section 110(k)(5), the EPA anticipates that a call for plan revisions under CAA section 111(d) will be done via notice and comment rulemaking.

administrative processes. The EPA proposes that a complete final state plan submittal under CAA section 111(d) must include: (1) A formal letter of submittal from the Governor or his/her designee requesting EPA approval of the plan or revision thereof; (2) evidence that the state has adopted the plan in the state code or body of regulations (That evidence must include the date of adoption or final issuance as well as the effective date of the plan, if different from the adoption/issuance date.); (3) evidence that the state has the necessary legal authority under state law to adopt and implement the plan; (4) a copy of the actual regulation, or document submitted for approval and incorporation by reference into the plan. The submittal must be a copy of the official state regulation/document signed, stamped and dated by the appropriate state official indicating that it is fully enforceable by the state (The effective date of the regulation/document must, whenever possible, be indicated in the document itself. The state's electronic copy must be an exact duplicate of the hard copy. For revisions to the approved plan, the submittal must indicate the changes made (for example, by redline/strikethrough) to the approved plan.); (5) evidence that the state followed all of the procedural requirements of the state's laws and constitution in conducting and completing the adoption/issuance of the plan; (6) evidence that public notice was given of the proposed change with procedures consistent with the requirements of 40 CFR 60.23, including the date of publication of such notice; (7) certification that public hearing(s) were held in accordance with the information provided in the public notice and the state's laws and constitution, if applicable and consistent with the public hearing requirements in 40 CFR 60.23; and (8) compilation of public comments and the state's response thereto.

These criteria, as proposed, are intended to be generic to all CAA section 111(d) plans going forward, with the proviso that specific EGs may provide otherwise. The technical support completeness criteria that the EPA proposes will also be generic to all CAA section 111(d) rules, with the same proviso. The EPA proposes that the technical support required for all plans must include each of the following: (1) Description of the plan approach and geographic scope; (2) identification of each designated facility, identification of emission standards for each designated facility, and monitoring, recordkeeping, and reporting requirements that will determine compliance by each designated facility; (3) identification of compliance schedules and/or increments of progress; (4) demonstration that the state plan submittal is projected to achieve emissions performance under the applicable EGs; (5) documentation of state recordkeeping and reporting requirements to determine the performance of the plan as a whole; and (6) demonstration that each emission standard is quantifiable, non-duplicative, permanent, verifiable, and enforceable.

The EPA proposes a process similar, though not identical, to that set forth in 40 CFR 51.103 and Appendix V to 40 CFR part 51 to make completeness determinations. Similar to CAA section 110(k)(1)(C), under this proposal, where the EPA determines that a state submission required under CAA section 111(d) does not meet the minimum completeness criteria we are proposing to establish, the state will be considered to have not made the submission. The EPA further proposes that, similar to CAA section 110(k)(1)(B), within 60 days of the EPA's receipt of a state submission, but no later than 6 months after the date, if any, by which a state is required to submit the plan or revision, the Administrator shall determine whether the minimum criteria have been met. Any plan or plan revision that a state submits to the EPA, and that has not been determined by the EPA by the date 6 months after receipt of the submission to have failed to meet the minimum criteria, shall on that date be deemed by operation of law to meet such minimum criteria. In cases where a state does not submit anything to the agency, however, the Administrator must make a finding of failure to submit no later than 6 months after the date, if any, by which a state is required to submit the plan or revision. (In other words, ''completeness by operation of law'' is only available where the state has actually submitted a plan to the agency.)

As with the completeness determination process for SIP submissions, the EPA's determination that a submittal is complete is not a finding that the submittal meets the substantive requirements of CAA section 111(d) or the guideline. That must be done via the process for approval or disapproval of a state plan, which would be done through notice and comment rulemaking. In the completeness process, the EPA will confirm that a state's submittal appears to have addressed the criteria for a complete submittal and, therefore, the submittal is sufficient to trigger the EPA's obligation to act on it. But in the completeness process the agency will not assess the content of those submissions to determine if they are approvable. Accordingly, even when the EPA affirmatively determines that a submittal is complete, it does not prevent the agency from later finding that the state plan does not meet the requirements of the EGs, including finding that the submittal failed to address a required element and must be disapproved.

Similarly, when a submittal is determined to be complete by operation of law after 6 months without the EPA's affirmative determination of completeness, the only legal consequence is that the EPA now has an obligation to act on that submittal. Completeness by operation of law means that the submittal is deemed complete and requires the EPA's review, whether or not the state has actually addressed all the required elements. Accordingly, if the agency determines that a state has failed to address a required element in its submittal once the EPA begins review of the state plan that is complete by operation of law, the agency must go through the process of disapproving (or partially disapproving or conditionally approving, as discussed below) that plan, unless the state and the EPA work together to cure the deficiency. In other words, the EPA cannot simply find the plan incomplete and return it to the state at that point. But the finding of completeness by operation of law in no way prevents the EPA from subsequently concluding that the state's submission is missing a required element of the program and making that finding as part of a disapproval of the plan.

As described in the final rulemaking action for the CAA section 111(d) EGs, a state will submit all CAA section 111(d) plans electronically. If the EPA determines that any submission fails to meet the completeness criteria, the agency may return the plan to the state and request corrections, identifying the components that are absent or insufficient to allow the EPA to perform a review of the plan. The state will not have met its obligation to submit a final plan until it resubmits a revised state plan or supporting materials addressing the corrections the EPA identified in its incompleteness determination.

The EPA is also proposing to include an exception to the criteria for complete administrative materials in cases where a state and the EPA are ''parallel processing'' the final plan. Parallel processing allows a state to submit the plan prior to final adoption by the state and provides an opportunity for the state to consider the EPA's comments prior to submission of a final plan for final review and action. The EPA would propose to take action on a state plan based on a proposed state regulation. The EPA would only finalize the action if the state adopts a final plan that is legally effective under state law. The EPA would only approve the plan if the state addressed any corrections that the EPA identified in its proposed action on the state plan without any other material change to the plan. Note that a plan submitted for parallel processing must still meet all the criteria for technical completeness so that the EPA and the public have a sufficient basis on which to evaluate and comment on the EPA's proposed action.

F. Update to Deadlines for EPA Actions

The EPA proposes to update the deadlines for acting on state submittals and promulgating a federal plan under 40 CFR 60.27(b), (c), and (d) to more closely track the current versions of CAA sections 110(c) and 110(k) adopted in 1990. The framework regulations for CAA section 111(d) state plans currently are parallel to the prior version of CAA section 110. They require the EPA to act on a state plan or plan revision submittal within 4 months after the date required for submission of a plan or plan revision. *See* 40 CFR 60.27(b). The regulations then require the EPA to issue a proposed federal plan in certain circumstances after consideration of any state hearing record, *see* 40 CFR 60.27(c), and require the EPA to promulgate the proposed federal plan within 6 months after the date required for plan submissions, *see* 40 CFR 60.27(d).

The final CO_2 EGs for affected EGUs have already adjusted the deadline in 40 CFR 60.27(b) to require the EPA to act on a state plan under those EGs within 12 months (rather than 4 months) after the date required for submission of a plan. *See* 40 CFR 60.5715. However, the Clean Power Plan EGs did not modify the 6-month deadline for a federal plan in 40 CFR 60.27(d).

The EPA is proposing to amend 40 CFR 60.27(b) to allow the EPA 12 months to approve or disapprove submittals of all plans or plan revisions under CAA section 111(d), not just those related to the Clean Power Plan under 40 CFR 60.5715. This change would provide the EPA with sufficient time for the steps required to approve or disapprove the submittal, which include proposing the EPA's approval or disapproval of the plan or plan revision, a public comment period on the EPA's proposal, time for the EPA to review and respond to public comments, and the issuance of a final rule approving or disapproving the plan or plan revision.

The EPA is also proposing to amend 40 CFR 60.27(b) to specify that the deadline for the EPA to act on a plan or plan revision is 12 months after receipt of a complete plan or plan revision, rather than 12 months after the deadline for submittal of a plan or plan revision. This amendment will allow the EPA to have the full 12 months to act on submittals of complete plans or plan revisions.

The EPA also proposes slight modifications to the provision related to issuing a proposed federal plan in 40 CFR 60.27(c); changing the 6-month deadline for issuing a final federal plan in 40 CFR 60.27(d) to 1 year;[123] and, similar to the change in timing for 40 CFR 60.27(b) above, setting the deadline for promulgation of a federal plan to run from the date of the EPA's action on a state submittal, rather than from the original deadline for a state submittal.

The EPA believes it is appropriate to modify these timing requirements for several reasons. First, the EPA notes that under CAA section 111(d)(2), Congress gave the EPA the ''same'' authority to prescribe a federal plan under CAA section 111(d) as it would have under CAA section 110(c) in the case of a state failure to submit a SIP. The term ''same'' stands in contrast to the term ''similar'' in CAA section 111(d)(1) (discussed above). As with the use of the term ''similar,'' the EPA believes it is authorized by this language to follow the timing provisions of CAA section 110(c) as currently enacted. Second, as a general matter, the timing requirements of current 40 CFR 60.27(c) and (d), which effectively require the EPA to propose and finalize a federal plan within 6 months of the deadline for state submittals, may be outdated and unrealistic with respect to the timelines for review of state plans and the time periods for action, particularly as informed by the agency's experience with CAA section 110 SIPs (which led to the extension of the timelines and other changes to CAA section 110 in the 1990 Amendments discussed above). Third, in the Clean Power Plan EGs, the EPA has finalized a timing requirement that gives the agency a year to approve or disapprove a state plan or revision. The existing requirement in 40 CFR 60.27(d) that the EPA must promulgate a federal plan within 6 months of the initial deadline for state plans is therefore inconsistent with this provision. Fourth, existing 40 CFR 60.27(c) tracks the prior version of CAA section 110(c) with respect to the issuance of a proposed federal plan. This relatively prescriptive language is no longer present in CAA section 110(c). The procedural requirements for rulemakings under both CAA section 110 and 111(d) are set out in section 307(d) of the CAA, and the EPA believes those provisions are appropriate and adequate to guide its rulemaking process for CAA section 111(d) federal plans.

The EPA invites comment on all of these proposed changes to the framework regulations. The EPA notes that the addition of these mechanisms to the framework regulations will make them available for all CAA section 111(d) regulations, not just those under the Clean Power Plan at 40 CFR part 60, subpart UUUU.

G. Proposed Interpretation Regarding Existing Sources That Modify or Reconstruct

In the proposed rulemaking for the Clean Power Plan, the EPA proposed the interpretation that if an existing source is subject to a CAA section 111(d) state plan, and then undertakes a modification or reconstruction, the source remains subject to the state plan, while also becoming subject to the modification or reconstruction requirements. *See* 79 FR 34830, 34903–4 (June 18, 2014). The EPA did not finalize a position on this issue in the final EGs rule, but indicated that it would re-propose and request comment on this issue through this federal plan rulemaking. The EPA also stated deferral of action on this issue does not impact states' and affected EGUs' pending obligations under the final Emission Guidelines relating to plan submission deadlines, as this issue concerns potential obligations or impacts after an existing source has already become subject to the requirements of a state plan. The EPA intends to finalize its position on this issue through this rulemaking, which will be well in advance of the plan performance period beginning in 2022, at which point state plan obligations on existing sources are effectuated.

We noted in the Clean Power Plan proposal that CAA section 111(d) is arguably silent as to this issue. Thus, we

[123] As under CAA section 110, the EPA believes that, should it fail for whatever reason to meet a deadline by which it was to take action, such as issue a federal plan, under CAA section 111(d), that failure does not thereby obviate or in any way remove the EPA's authority or obligation to take that action. *See Oklahoma* v. *U.S. EPA,* 723 F.3d 1201, 1224 (10th Cir. 2013) (''Although the statute undoubtedly requires that the EPA promulgate a FIP within two years, it does not stand to reason that it loses its ability to do so after this two-year period expires. Rather, the appropriate remedy when the EPA violates the statute is an order compelling agency action.'').

took this to grant the agency the authority to provide a reasonable interpretation to fill in the gaps where the statute is silent. In the proposal for the Clean Power Plan, we proposed to disallow existing sources to leave the CAA section 111(d) program through modification or reconstruction. We did this for two reasons. First, if a source did so, that could prove disruptive to the state plan. Second, allowing sources to do so could provide them an incentive that would be contrary to the purposes of CAA section 111(d). We then asked for comment on ''whether this interpretation is supported by the statutory text and whether this interpretation is sensible policy and will further the goals of the statute.''

We received many comments disagreeing with this approach. After reviewing these comments, the agency believes an alternative interpretation is more appropriate in the particular context here. In order to give the public an opportunity to comment on this, we are proposing this interpretation here. That is, when CAA section 111(d) EGs are initially promulgated for existing stationary sources in response to corresponding CAA section 111(b) standards of performance for the same pollutant, the statute prevents new, modified, or reconstructed sources (including under those particular CAA section 111(b) standards of performance and as those terms are applied in the relevant new source performance standards (NSPS)) from simultaneously being subject to state plans under those particular CAA section 111(d) EGs. This interpretation gives meaning to the definition of ''existing source'' in CAA section 111(a)(6) and is consistent with the definition of ''new source'' in CAA section 111(a)(2). Further, it is consistent with the historical treatment of modified and reconstructed sources in the CAA section 111 program.

The EPA notes the concerns it noted in the proposal supporting why the originally proposed interpretation was reasonable are being addressed in other ways in the final EGs, and in the proposed federal plan. In other words, there will be other ways to minimize disruption to state plans if such a modification or reconstruction were to take place. We invite comment on the agency's proposed interpretation that when an existing source modifies or reconstructs in such a way that it meets the definition of a new source, for purposes of a particular NSPS and emission guideline, it becomes a new source under the statute and is no longer subject to the CAA section 111(d) program

H. Separate Finalization of These Changes

The agency intends to finalize these procedural changes and interpretation sooner than it finalizes the rest of this proposed action. The EPA believes these changes generally enhance and improve the framework regulations in a way that will be of benefit to the states, the EPA, and other stakeholders, and will improve the overall efficacy of the program. We believe it is important to finalize these changes to the framework regulations relatively quickly in order to provide states and other stakeholders predictability in how the EPA intends to process state plans and submissions under CAA section 111(d). If the EPA does finalize these changes sooner than the model trading rules or the federal plan, it will do so after the close of the comment period, and after consideration and response to any comments on these changes.

VIII. Impacts of This Action

A. Endangered Species Act

Consistent with the requirements of section 7(a)(2) of the Endangered Species Act (ESA), the EPA has considered the effects of this proposed rule and has reviewed applicable ESA regulations, case law, and guidance to determine what, if any, impact there may be to listed endangered or threatened species or designated critical habitat. Section 7(a)(2) of the ESA requires federal agencies, in consultation with the U.S. Fish and Wildlife Service (FWS) and/or the National Marine Fisheries Service, to ensure that actions they authorize, fund, or carry out are not likely to jeopardize the continued existence of federally listed endangered or threatened species or result in the destruction or adverse modification of designated critical habitat of such species. *See* 16 U.S.C. 1536(a)(2). Under relevant implementing regulations, ESA section 7(a)(2) applies only to actions where there is discretionary federal involvement or control. *See* 50 CFR 402.03. Further, under the regulations consultation is required only for actions that ''may affect'' listed species or designated critical habitat. *See* 50 CFR 402.14. Consultation is not required where the action has no effect on such species or habitat. Under this standard, it is the federal agency taking the action that evaluates the action and determines whether consultation is required. *See* 51 FR 19926, 19949 (June 3, 1986). Effects of an action include both the direct and indirect effects that will be added to the environmental baseline. *See* 50 CFR 402.02. Direct effects are the direct or immediate effects of an action on a listed species or its habitat.[124] Indirect effects are those that are caused by the action, later in time, and are reasonably certain to occur. *Id.* To trigger a consultation requirement, there must thus be a causal connection between the federal action, the effect in question, and if the effect is indirect, it must be reasonably certain to occur.

The EPA has considered the effects of this proposed rule and has reviewed applicable ESA regulations, case law, and guidance to determine what, if any, impact there may be to listed species or designated critical habitat for purposes of ESA section 7(a)(2) consultation. The EPA notes that the projected environmental effects of this proposal are, like the EGs that it implements, positive: Reductions in overall GHG emissions, and reductions in PM and ozone-precursor emissions (sulfur oxides and NO_X), for EGUs that will be covered by the federal plan. However, the EPA's assessment that the rule will have an overall net positive environmental effect by virtue of reducing emissions of certain air pollutants does not address whether the rule may affect any listed species or designated critical habitat for ESA section 7(a)(2) purposes and does not constitute any finding of effects for that purpose. The fact that the rule will have overall positive effects on the national and global environment does not mean that the rule may affect any listed species in its habitat or the designated critical habitat of such species within the meaning of ESA section 7(a)(2) or the implementing regulations or require ESA consultation. The EPA has considered various types of potential effects in considering whether ESA consultation is required for this rule.

With respect to the projected GHG emission reductions, the EPA does not believe that such reductions trigger ESA consultation requirements under ESA section 7(a)(2). In reaching this conclusion, the EPA is mindful of significant legal and technical analysis undertaken by FWS and the U.S. Department of the Interior (DOI) in the context of listing the polar bear as a threatened species under the ESA. In that context, in 2008, FWS and DOI expressed the view that the best scientific data available were insufficient to draw a causal connection

[124] *See* Endangered Species Consultation Handbook, U.S. Fish & Wildlife Service and National Marine Fisheries Service at 4–25 (March 1998) (providing examples of direct effects: *e.g.,* driving an off road vehicle through the nesting habitat of a listed species of bird and destroying a ground nest; building a housing unit and destroying the habitat of a listed species).

between GHG emissions and effects on the species in its habitat.[125] The DOI Solicitor concluded that where the effect at issue is climate change, proposed actions involving GHG emissions cannot pass the ''may affect'' test of the ESA section 7 regulations and, thus, are not subject to ESA consultation.

The EPA has also previously considered issues relating to GHG emissions in connection with the requirements of ESA section 7(a)(2). In the final EGs, the agency noted that, although the GHG emission reductions projected for the EGs are large (estimated reductions of about 415 million short tons of CO_2 in 2030 relative to the base case), the EPA evaluated larger reductions in assessing this same issue in the context of the light duty vehicle GHG emission standards for model years 2012–2016 and 2017–2025. There the agency projected emission reductions over the lifetimes of the model years in question,[126] which are roughly five to six times those projected above and, based on air quality modeling of potential environmental effects, concluded that ''EPA knows of no modeling tool which can link these small, time-attenuated changes in global metrics to particular effects on listed species in particular areas. Extrapolating from global metric to local effect with such small numbers, and accounting for further links in a causative chain, remain beyond current modeling capabilities.'' EPA, *Light Duty Vehicle Greenhouse Gas Standards and Corporate Average Fuel Economy Standards,* Response to Comment Document for Joint Rulemaking at 4–102 (Docket EPA–OAR–HQ–2009–4782). The EPA reached this conclusion after evaluating issues relating to potential improvements from the fuel efficiency rule relevant to both temperature and oceanographic pH outputs. The EPA's ultimate finding was that ''any potential for a specific impact [of the specific federal action] on listed species in their habitats associated with these very small changes in average global temperature and ocean pH is too remote to trigger the threshold for ESA section 7(a)(2).'' *Id. See also, e.g., Ground Zero Center for Non-Violent Action* v. *U.S. Dept. of Navy,* 383 F. 3d 1082, 1091–92 (9th Cir. 2004). The EPA similarly proposes to determine that the likelihood of jeopardy to a species from this proposed action is extremely remote, and ESA does not require consultation. The EPA's proposed conclusion is entirely consistent with DOI's analysis regarding ESA requirements in the context of federal actions involving GHG emissions.

With regard to non-GHG air emissions, the EPA is also projecting substantial reductions of SO_2 and NO_X as a collateral consequence of this proposal (which will be, as stated above, only a subset of the total reductions from the EGs). However, CAA section 111(d) cannot directly control emissions of criteria pollutants. And furthermore, a federal plan under CAA section 111(d)(2) does no more than prescribe emissions standards of the same stringency as the corresponding EGs. *See* 40 CFR 60.27(e)(1). Consequently, CAA section 111(d) provides no discretion to set a standard in a federal plan based on potential impacts to endangered species of reduced criteria pollutant emissions. ESA section 7(a)(2) consultation is not required with respect to the projected reductions of criteria pollutant emissions. *See* 50 CFR 402.03; *see also WildEarth Guardians* v. *U.S. Envt'l Protection Agency,* 759 F.3d 1196, 1207–10 (10th Cir. 2014) (the EPA has no duty to consult under section 7 of the ESA regarding HAP controls that it did not require—and likely lacked authority to require—in a FIP for regional haze controls under section 169A of the CAA.).

Finally, the EPA has also considered other potential effects of the rule (beyond reductions in air pollutants) and whether any such effects are ''caused by'' the rule and ''reasonably certain to occur'' within the meaning of the ESA regulatory definition of the effects of an action. *See* 50 CFR 402.02. The EPA recognizes, for instance, that questions may exist whether decisions such as increased utilization of solar or wind power could have effects on listed species. The EPA received comments on the EGs asserting that because potential increased reliance on wind or solar power may be an element of Building Block 3, and because wind and solar facilities may in some cases have effects on listed species, the EPA must consult under the ESA on this aspect of the rule.

The EPA has carefully considered the comments and the correspondence from Congress as well as the case law and other materials cited in those documents. The EPA does not believe that the effects of potential future changes in the energy sector—including increased reliance on wind or solar power as a result of future potential actions by states or other implementing entities—or any potential alterations in the operations of any particular facility would, at the time of promulgation of a federal plan, be sufficiently certain to occur so as to require ESA consultation on the rule. The EPA appreciates that the ESA regulations call for consultation where actions authorized, funded, or carried out by federal agencies may have indirect effects on listed species or designated critical habitat. However, as noted above, indirect effects must be caused by the action at issue and must be reasonably certain to occur.

Under a federal plan, it is the EPA that would implement a CAA section 111(d) plan. The EPA believes that even with this proposed federal plan, any effects on listed species or designated habitat are too uncertain to require consultation under ESA section 7. This is so for at least two reasons: (1) The EPA cannot know with any certainty at this stage which states will actually become subject to a finally promulgated federal plan. Which affected EGUs, in which states, will be covered by this plan can only be known after states have failed to submit a plan, or have had their plans disapproved by the EPA; and (2) the federal plan as proposed will be implemented through some form of emissions trading. Emissions trading inherently provides maximum flexibility to individual affected EGUs to choose their method of compliance, including continuing to emit the relevant pollutant at historical rates so long as the affected EGU holds sufficient credits or allowances. At this point, the EPA has no meaningful information to express in any more than the broadest terms how any particular affected EGU may choose to comply with the federal plan, should it be promulgated for them based on their location in an area not covered by an approved state plan. The Services have explained that ESA section 7(a)(2) was not intended to preclude federal actions based on potential future speculative effects.[127]

[125] *See, e.g.,* 73 FR 28212, 28300 (May 15, 2008); Memorandum from David Longly Bernhardt, Solicitor, U.S. Department of the Interior re: ''Guidance on the Applicability of the Endangered Species Act's Consultation Requirements to Proposed Actions Involving the Emission of Greenhouse Gases'' (October 3, 2008).

[126] *See* 75 FR 25438 Table I.C 2–4 (May 7, 2010); 77 FR at 62894 Table III–68 (October 15, 2012).

[127] *See* 51 FR 19933 (describing effects that are ''reasonably certain to occur'' in the context of consideration of cumulative effects and distinguishing broader consideration that may be appropriate in applying a procedural statute such as the National Environmental Policy Act, as opposed to a substantive provision such as ESA section 7(a)(2) that may prohibit certain federal actions); Endangered Species Consultation Handbook, U.S. Fish & Wildlife Service and National Marine Fisheries Service at 4–30 (March 1998) (in the same context, describing indicators that an activity is reasonably certain to occur as including governmental approvals of the action or indications that such approval is imminent, project sponsors' assurance that the action will proceed, obligation of venture capital, or initiation of contracts; and noting that the more governmental

These are precisely the types of speculative future activities and effects currently at issue here. The EPA requests comment on its proposed conclusion that ESA section 7 consultation is not required for this action. The EPA will continue to evaluate the scope and potential effects of federal planning activities for this source category to the extent federal plans are needed and implemented in specific areas and over specific sources.

B. What are the air impacts?

The EPA anticipates significant emission reductions under this proposed action for the utility power sector. Specifically, the EPA is proposing approaches in the form of mass- and rate-based trading options that provide flexibility in implementing emission standards for a state's affected EGUs. Both proposed approaches to the federal plan would require affected EGUs to meet emission standards set using the CO_2 emission performance rates in the Clean Power Plan EGs.

However, at the time of this proposal, the EPA has no information on whether any or how many states will require a federal plan or will adopt a model rule. Because of this lack of information, in the Regulatory Impact Analysis (RIA) for this proposal, the EPA chose to examine a scenario where all states of the contiguous United States will be regulated under a federal plan or will adopt the model rule. Additionally, we examine two alternative federal plan approach scenarios. The first federal plan approach assumes all states in the contiguous United States are regulated under a rate-based federal plan. The second federal plan approach assumes all contiguous states are regulated under a mass-based federal plan.[128]

Under the rate-based approach, when compared to 2005, CO_2 emissions are projected to be reduced by approximately 22 percent in 2020, 28 percent in 2025, and 32 percent in 2030. Under the mass-based approach, when compared to 2005, CO_2 emissions are projected to be reduced by approximately 23 percent in 2020, 29 percent in 2025, and 32 percent in 2030. The proposal is projected to result in substantial co-benefits through reductions of SO_2, NO_X, and $PM_{2.5}$ that will have direct public health benefits by lowering ambient levels of these pollutants and ozone. Table 12 and Table 13 of this preamble show expected CO_2 and other air pollutant emissions in the base case and reductions under the proposal for 2020, 2025, and 2030 for both rate-based and mass-based approaches.

TABLE 12—SUMMARY OF CO_2 AND OTHER AIR POLLUTANT EMISSION REDUCTIONS FROM THE BASE CASE UNDER RATE-BASED FEDERAL PLAN APPROACH

	CO_2 (million short tons)	SO_2 (thousand short tons)	NO_X (thousand short tons)
2020			
Base Case	2,155	1,311	1,333
Rate-based Federal Plan Approach	2,085	1,297	1,282
Emission Reductions	69	14	50
2025			
Base Case	2,165	1,275	1,302
Rate-based Federal Plan Approach	1,933	1,097	1,138
Emission Reductions	232	178	165
2030			
Base Case	2,227	1,314	1,293
Rate-based Federal Plan Approach	1,812	996	1,011
Emission Reductions	415	318	282

Source: Integrated Planning Model, 2015.
Note: Emissions may not sum due to rounding.

TABLE 13—SUMMARY OF CO_2 AND OTHER AIR POLLUTANT EMISSION REDUCTIONS FROM THE BASE CASE UNDER MASS-BASED FEDERAL PLAN APPROACH

	CO_2 (million short tons)	SO_2 (thousand short tons)	NO_X (thousand short tons)
2020			
Base Case	2,155	1,311	1,333
Mass-based Federal Plan Approach	2,073	1,257	1,272
Emission Reductions	81	54	60
2025			
Base Case	2,165	1,275	1,302
Mass-based Federal Plan Approach	1,901	1,090	1,100

administrative discretion remains to be exercised, the less there is reasonable certainty the action will proceed).

[128] It is important to note that the differences between the analytical results for the rate-based and mass-based federal plan approaches presented may not be indicative of likely differences between the approaches. If one approach performs differently than the other on a given metric during a given time period, this does not imply this will apply in all instances.

TABLE 13—SUMMARY OF CO_2 AND OTHER AIR POLLUTANT EMISSION REDUCTIONS FROM THE BASE CASE UNDER MASS-BASED FEDERAL PLAN APPROACH—Continued

	CO_2 (million short tons)	SO_2 (thousand short tons)	NO_X (thousand short tons)
Emission Reductions	265	185	203
2030			
Base Case	2,227	1,314	1,293
Mass-based Federal Plan Approach	1,814	1,034	1,015
Emission Reductions	413	280	278

Source: Integrated Planning Model, 2015.
Note: Emissions may not sum due to rounding.

The reductions in Tables 12 and 13 of this preamble do not account for reductions in HAP that may occur as a result of this rule. For instance, the fine particulate reductions presented above do not reflect all of the reductions in many heavy metal particulates.

C. What are the energy impacts?

The proposed action may have important energy market implications. Table 14 of this preamble presents a variety of important energy market impacts for 2020, 2025, and 2030 under both the rate-based and mass-based federal plan approaches described in section VIII.B of this preamble and presented in the RIA for this proposal.

TABLE 14—SUMMARY TABLE OF IMPORTANT ENERGY MARKET IMPACTS FOR RATE-BASED AND MASS-BASED FEDERAL PLAN APPROACHES

[Percent change from base case]

	Rate-Based			Mass-Based		
	2020	2025	2030	2020	2025	2030
Retail electricity prices	3%	1%	1%	3%	2%	0%
Average electricity bills	3	−4	−7	2	−3	−8
Price of coal at minemouth	−1	−5	−4	−1	−5	−3
Coal production for power sector use	−5	−14	−25	−7	−17	−24
Price of natural gas delivered to power sector	5	−8	2	4	−3	−2
Natural gas use for electricity generation	3	−1	−1	5	0	−4

These figures reflect the EPA's modeling that presumes policies that lead to generation shifts and growing use of DS–EE and renewable electricity generation out to 2029. If different implementation choices are made than those modeled, impacts could be different.

D. What are the compliance costs?

The compliance costs of this proposed action are represented in this analysis as the change in electric power generation costs between the base case and modeled federal plan approaches described in section VIII.B of this preamble and presented in the RIA for this proposal. The incremental cost is the projected additional cost of complying with the proposed action in the year analyzed and includes the amortized cost of capital investment, needed new capacity, shifts between or among various fuels, deployment of DS–EE programs, and other actions associated with compliance. These important dynamics are discussed in more detail in the RIA in the rulemaking docket.

The EPA estimates the annual incremental compliance cost for the rate-based federal plan approach to be $2.5 billion in 2020, $1.0 billion in 2025 and $8.4 billion in 2030. The EPA estimates the annual incremental compliance cost for the mass-based federal plan approach to be $1.4 billion in 2020, $3.0 billion in 2025, and $5.1 billion in 2030. More detailed cost estimates are available in the RIA in the rulemaking docket.

E. What are the economic and employment impacts?

Based on the analysis presented in the RIA, the proposed action is projected to result in certain changes to power system operation as a compliance approach with the standards. See Table 14 of this preamble for a variety of important energy market impacts for 2020, 2025, and 2030 under both the rate-based and mass-based federal plan approaches described in Section VIII.B of this preamble and presented in the RIA for this proposal.

Changes in price or demand for electricity, natural gas, and coal can impact markets for goods and services produced by sectors that use these energy inputs in the production process or supply those sectors. Changes in the cost of production may result in changes in prices, quantities produced, and profitability of affected firms. The EPA recognizes that the EGs provide significant flexibilities and states implementing the EGs may choose to mitigate impacts to some markets outside the utility power sector. Similarly, demand for new generation or DS–EE as a result of states implementing the guidelines can result in shifts in production and profitability for firms that supply those goods and services.

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. While the economy continues to move toward full employment, employment impacts are of particular concern and questions may arise about their existence and magnitude.

The EPA's employment analysis includes projected employment impacts associated with modeled federal plan approaches for the electric power industry, coal and natural gas production, and DS–EE activities. These projections are derived, in part, from a detailed model of the utility power sector used for this regulatory analysis, and U.S. government data on employment and labor productivity. In the electricity, coal, and natural gas sectors, the EPA estimates that the proposed action could result in a net decrease of approximately 25,000 job-years in 2025 under the rate-based federal plan approach and approximately 26,000 job-years in 2025 under the mass-based approach. For 2030, the estimates of the net decrease in job-years are 31,000 under the rate-based approach and 34,000 under the mass-based approach. The agency is also offering an illustrative calculation of potential employment effects due to DS–EE programs. Employment impacts from DS–EE programs in 2030 could range from approximately 52,000 to 83,000 jobs under the proposal.

By its nature, DS–EE reduces overall demand for electric power. The EPA recognizes as more efficiency is built into the U.S. power system over time, lower fuel requirements may lead to fewer jobs in the coal and natural gas extraction sectors, as well as in fossil fuel-fired EGU construction and operation than would otherwise have been expected. The EPA also recognizes the fact that, in many cases, employment gains and losses that might be attributable to this rule would be expected to affect different sets of people. Moreover, workers who lose jobs in these sectors may find employment elsewhere just as workers employed in new jobs in these sectors may have been previously employed elsewhere. Therefore, the employment estimates reported in these sectors may include workers previously employed elsewhere. This analysis also does not capture potential economy-wide impacts due to changes in prices (of fuel, electricity, or labor, for example) or other factors such as improved labor productivity and reduced health care expenditures resulting from cleaner air. For these reasons, the numbers reported here should not be interpreted as a net national employment impact.

F. What are the benefits of the proposed action?

Implementing the proposed action will generate benefits by reducing emissions of CO_2 and criteria pollutant precursors, including SO_2, NO_X, and directly emitted particles. SO_2 and NO_X are precursors to $PM_{2.5}$ (particles smaller than 2.5 microns), and NO_X is a precursor to ozone. The estimated benefits associated with these emission reductions are beyond those achieved by previous EPA rulemakings including the Mercury and Air Toxics Standards rule. The health and welfare benefits from reducing air pollution are considered co-benefits for this proposal. For this rulemaking, we were only able to quantify the climate benefits from reduced emissions of CO_2 and the health co-benefits associated with reduced exposure to $PM_{2.5}$ and ozone. There are many additional benefits which we are not able to quantify, leading to an underestimate of monetized benefits. In summary, we estimate the total combined climate benefits and health co-benefits for the rate-based federal plan approach to be $3.5 to $4.6 billion in 2020, $18 to $28 billion in 2025, and $34 to $54 billion in 2030 (3 percent discount rate, 2011$). Total combined climate benefits and health co-benefits for the mass-based federal plan approach are estimated to be $5.3 to $8.1 billion in 2020, $19 to $29 billion in 2025, and $32 to $48 billion in 2030 (3 percent discount rate, 2011$). A summary of the emission reductions and monetized benefits estimated for this rule at all discount rates is provided in Tables 15 through 17 of this preamble.

TABLE 15—SUMMARY OF THE MONETIZED GLOBAL CLIMATE BENEFITS FOR THE PROPOSAL

[Billions of 2011$][a]

Year	Discount rate (statistic)	Monetized climate benefits		
		2020	2025	2030
Rate-based Federal Plan Approach				
CO_2 Reductions (million short tons)		69	232	415
	5 percent (average SC–CO_2)	$0.80	$3.1	$6.4
	3 percent (average SC–CO_2)	2.8	10	20
	2.5 percent (average SC–CO_2)	4.1	15	29
	3 percent (95th percentile SC–CO_2)	8.2	31	61
Mass-based Federal Plan Approach				
CO_2 Reductions (million short tons)		81	265	413
	5 percent (average SC–CO_2)	$0.94	$3.6	$6.4
	3 percent (average SC–CO_2)	3.3	12	20
	2.5 percent (average SC–CO_2)	4.9	17	29
	3 percent (95th percentile SC–CO_2)	9.7	35	60

[a] Climate benefit estimates reflect impacts from CO_2 emission changes in the analysis years presented in the table and do not account for changes in non-CO_2 GHG emissions. These estimates are based on the global social cost of carbon (SC–CO_2) estimates for the analysis years and are rounded to two significant figures.

TABLE 16—SUMMARY OF THE MONETIZED HEALTH CO-BENEFITS IN THE U.S. FOR THE PROPOSAL, RATE-BASED FEDERAL PLAN APPROACH

[Billions of 2011$] [a]

Pollutant	National emission reductions (thousands of short tons)	Monetized health co-benefits (3 percent discount)	Monetized health co-benefits (7 percent discount)
Rate-Based Federal Plan Approach, 2020			
$PM_{2.5}$ precursors [b]			
SO_2	14	$0.44 to $0.99	$0.39 to $0.89
NO_X	50	$0.14 to $0.33	$0.13 to $0.30
Ozone precursor [c]			
NO_X (ozone season only)	19	$0.12 to $0.52	$0.12 to $0.52
Total Monetized Health Co-benefits		$0.70 to $1.8	$0.64 to $1.7
Total Monetized Health Co-benefits combined with Monetized Climate Benefits [d]		$3.5 to $4.6	$3.5 to $4.5
Rate-Based Federal Plan Approach, 2025			
$PM_{2.5}$ precursors [b]			
SO_2	178	$6.4 to $14	$5.7 to $13
NO_X	165	$0.56 to $1.3	$0.50 to $1.1
Ozone precursor [c]			
NO_X (ozone season only)	70	$0.49 to $2.1	$0.49 to $2.1
Total Monetized Health Co-benefits		$7.4 to $18	$6.7 to $16
Total Monetized Health Co-benefits combined with Monetized Climate Benefits [d]		$18 to $28	$17 to $26
Rate-Based Federal Plan Approach, 2030			
$PM_{2.5}$ precursors [b]			
SO_2	318	$12 to $28	$11 to $25
NO_X	282	$1.0 to $2.3	$0.93 to $2.1
Ozone precursor [c]			
NO_X (ozone season only)	118	$0.86 to $3.7	$0.86 to $3.7
Total Monetized Health Co-benefits		$14 to $34	$13 to $31
Total Monetized Health Co-benefits combined with Monetized Climate Benefits [d]		$34 to $54	$33 to $51

[a] All estimates are rounded to two significant figures, so estimates may not sum. It is important to note that the monetized co-benefits do not include reduced health effects from direct exposure to SO_2, direct exposure to NO_2, exposure to mercury, ecosystem effects, or visibility impairment. Air pollution health co-benefits are estimated using regional benefit-per-ton estimates for the contiguous United States.

[b] The monetized $PM_{2.5}$ co-benefits reflect the human health benefits associated with reducing exposure to $PM_{2.5}$ through reductions of $PM_{2.5}$ precursors, such as SO_2 and NO_X. The co-benefits do not include the benefits of reductions in directly emitted $PM_{2.5}$. These additional benefits would increase overall benefits by a few percent based on the analyses conducted for the proposed Clean Power Plan EGs. PM co-benefits are shown as a range reflecting the use of two concentration-response functions, with the lower end of the range based on a function from Krewski et al. (2009) and the upper end based on a function from Lepeule et al. (2012). These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effect estimates by particle type.

[c] The monetized ozone co-benefits reflect the human health benefits associated with reducing exposure to ozone through reductions of NO_X during the ozone season. Ozone co-benefits are shown as a range reflecting the use of several different concentration-response functions, with the lower end of the range based on a function from Bell, et al. (2004) and the upper end based on a function from Levy, et al. (2005). Ozone co-benefits occur in the analysis year, so they are the same for all discount rates.

[d] We estimate climate benefits associated with four different values of a one ton CO_2 reduction (model average at 2.5 percent discount rate, 3 percent, and 5 percent; 95th percentile at 3 percent). Referred to as the social cost of carbon, each value increases over time. 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 carbon values. We provide combined climate and health estimates based on additional discount rates in the RIA.

TABLE 17—SUMMARY OF THE MONETIZED HEALTH CO-BENEFITS IN THE U.S. FOR THE PROPOSAL, MASS-BASED FEDERAL PLAN APPROACH

[Billions of 2011$] [a]

Pollutant	National emission reductions (thousands of short tons)	Monetized health co-benefits (3 percent discount)	Monetized health co-benefits (7 percent discount)
Mass-Based Federal Plan Approach, 2020			
$PM_{2.5}$ precursors [b]			
SO_2	54	$1.7 to $3.8	$1.5 to $3.4
NO_X	60	$0.17 to $0.39	$0.16 to $0.36
Ozone precursor [c]			
NO_X (ozone season only)	23	$0.14 to $0.61	$0.14 to $0.61
Total Monetized Health Co-benefits		$2.0 to $4.8	$1.8 to $4.4
Total Monetized Health Co-benefits combined with Monetized Climate Benefits [d]		$5.3 to $8.1	$5.1 to $7.7
Mass-Based Federal Plan Approach, 2025			
$PM_{2.5}$ precursors [b]			
SO_2	185	$6.0 to $13	$5.4 to $12
NO_X	203	$0.58 to $1.3	$0.52 to $1.2
Ozone precursor [c]			
NO_X (ozone season only)	88	$0.56 to $2.4	$0.56 to $2.4
Total Monetized Health Co-benefits		$7.1 to $17	$6.5 to $16
Total Monetized Health Co-benefits combined with Monetized Climate Benefits [d]		$19 to $29	$18 to $27
Mass-Based Federal Plan Approach, 2030			
$PM_{2.5}$ precursors [b]			
SO_2	280	$10 to $23	$9.0 to $20
NO_X	278	$0.87 to $2.0	$0.79 to $1.8
Ozone precursor [c]			
NO_X (ozone season only)	121	$0.82 to $3.5	$0.82 to $3.5
Total Monetized Health Co-benefits		$12 to $28	$11 to $26
Total Monetized Health Co-benefits combined with Monetized Climate Benefits [d]		$32 to $48	$31 to $46

[a] All estimates are rounded to two significant figures, so estimates may not sum. It is important to note that the monetized co-benefits do not include reduced health effects from direct exposure to SO_2, direct exposure to NO_2, exposure to mercury, ecosystem effects, or visibility impairment. Air pollution health co-benefits are estimated using regional benefit-per-ton estimates for the contiguous United States.

[b] The monetized $PM_{2.5}$ co-benefits reflect the human health benefits associated with reducing exposure to $PM_{2.5}$ through reductions of $PM_{2.5}$ precursors, such as SO_2 and NO_X. The co-benefits do not include the benefits of reductions in directly emitted $PM_{2.5}$. These additional benefits would increase overall benefits by a few percent based on the analyses conducted for the proposed Clean Power Plan EGs. PM co-benefits are shown as a range reflecting the use of two concentration-response functions, with the lower end of the range based on a function from Krewski et al. (2009) and the upper end based on a function from Lepeule et al. (2012). These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effect estimates by particle type.

[c] The monetized ozone co-benefits reflect the human health benefits associated with reducing exposure to ozone through reductions of NO_X during the ozone season. Ozone co-benefits are shown as a range reflecting the use of several different concentration-response functions, with the lower end of the range based on a function from Bell, et al. (2004) and the upper end based on a function from Levy, et al. (2005). Ozone co-benefits occur in the analysis year, so they are the same for all discount rates.

[d] We estimate climate benefits associated with four different values of a one ton CO_2 reduction (model average at 2.5 percent discount rate, 3 percent, and 5 percent; 95th percentile at 3 percent). Referred to as the social cost of carbon, each value increases over time. 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 carbon values. We provide combined climate and health estimates based on additional discount rates in the RIA.

The EPA has used the social cost of carbon (SC–CO_2) estimates presented in the *Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866 (May 2013, Revised July 2015)* (''current TSD'') to analyze CO_2 climate impacts of this rulemaking.[129] We refer to these

[129] Docket ID EPA–HQ–OAR–2013–0495, Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact

Continued

estimates, which were developed by the U.S. government, as ''SC–CO_2 estimates.'' 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. It includes a wide range of anticipated climate impacts, such as net changes in agricultural productivity and human health, property damage from increased flood risk, and changes in energy system costs, such as reduced costs for heating and increased costs for air conditioning. It is typically used to assess the avoided damages as a result of regulatory actions (*i.e.,* benefits of rulemakings that lead to an incremental reduction in cumulative global CO_2 emissions).

The SC–CO_2 estimates used in this analysis were developed over many years, using the best science available, and with input from the public. Specifically, an interagency working group (IWG) that included the 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) [130] provides a complete discussion of the methods used to develop these estimates and the current TSD presents and discusses the 2013 update (including two recent minor corrections to the estimates).[131]

Analysis Under Executive Order 12866, Interagency Working Group on Social Cost of Carbon, with participation by Council of Economic Advisers, Council on Environmental Quality, Department of Agriculture, Department of Commerce, DOE, Department of Transportation, Domestic Policy Council, Environmental Protection Agency, National Economic Council, Office of Management and Budget, Office of Science and Technology Policy, and Department of Treasury (May 2013, Revised July 2015). Available at: *http://www.whitehouse.gov/sites/default/files/omb/inforeg/scc-tsd-final-july-2015.pdf.*

[130] Docket ID EPA–HQ–OAR–2009–0472–114577, Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866, Interagency Working Group on Social Cost of Carbon, with participation by the Council of Economic Advisers, Council on Environmental Quality, Department of Agriculture, Department of Commerce, Department of Energy, Department of Transportation, Environmental Protection Agency, National Economic Council, Office of Energy and Climate Change, Office of Management and Budget, Office of Science and Technology Policy, and Department of Treasury (February 2010). Also available at: *http://www.whitehouse.gov/sites/default/files/omb/inforeg/for-agencies/Social-Cost-of-Carbon-for-RIA.pdf.*

[131] The current version of the TSD is available at: *https://www.whitehouse.gov/sites/default/files/omb/inforeg/scc-tsd-final-july-2015.pdf,* Docket ID EPA–HQ–OAR–2013–0495, *Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866,* Interagency Working Group on Social Cost of Carbon, with participation by Council of Economic Advisers, Council on Environmental Quality, Department of Agriculture, Department of Commerce, Department of Energy, Department of Transportation, Domestic Policy Council, Environmental Protection Agency, National Economic Council, Office of Management and Budget, Office of Science and Technology Policy, and Department of Treasury (May 2013, Revised July 2015).

OMB's Office of Information and Regulatory Affairs received comments in response to a request for public comment on the approach used to develop the estimates. After careful evaluation of the full range of comments submitted to OMB, the IWG continues to recommend the use of the SC–CO_2 estimates in RIA.[132] With the release of the response to comments, the IWG announced plans to obtain expert independent advice from the National Academies of Sciences, Engineering, and Medicine (Academies) to ensure that the SC–CO_2 estimates continue to reflect the best available scientific and economic information on climate change. The Academies review will be informed by the public comments received and focus on the technical merits and challenges of potential approaches to improving the SC–CO_2 estimates in future updates. See the EPA Response to Comments document for the complete response to comments received on SC–CO_2 as part of this rulemaking.

Concurrent with OMB's publication of the response to comments on SC–CO_2 and announcement of the Academies process, OMB posted a revised TSD that includes two minor technical corrections to the current estimates. One technical correction addressed an inadvertent omission of climate change damages in the last year of analysis (2300) in one model and the second addressed a minor indexing error in another model. On average the revised SC–CO_2 estimates are one dollar less than the mean SC–CO_2 estimates reported in the November 2013 revision to the May 2013 TSD. The change in the estimates associated with the 95th percentile estimates when using a 3 percent discount rate is slightly larger, as those estimates are heavily influenced by the results from the model that was affected by the indexing error.

The EPA, as a member of the IWG on the SC–CO_2, has carefully examined and evaluated the minor technical corrections in the revised TSD and the public comments submitted to OMB's SC–CO_2 comment process. The EPA concurs with the IWG's conclusion that it is reasonable, and scientifically appropriate, to use the current SC–CO_2 estimates for purposes of RIA, including for this proceeding.

[132] See *https://www.whitehouse.gov/omb/oira/social-cost-of-carbon* for additional details, including the OMB Response to Comments and the SC–CO_2 TSDs.

The four SC–CO_2 estimates are as follows: $12, $40, $60, and $120 per short ton of CO_2 emissions in the year 2020 (2011$).[133] The first three values are based on the average SC–CO_2 from the three IAMs, at discount rates of 5, 3, and 2.5 percent, respectively. The SC–CO_2 value at several discount rates are included because the literature shows that the SC–CO_2 is quite sensitive to assumptions about the discount rate, and because no consensus exists on the appropriate rate to use in an intergenerational context (where costs and benefits are incurred by different generations). The fourth value is the 95th percentile of the SC–CO_2 from all three models at a 3 percent discount rate. It is included to represent higher-than-expected impacts from temperature change further out in the tails of the SC–CO_2 distribution (representing less likely, but potentially catastrophic, outcomes).

There are limitations in the estimates of the benefits from this proposal, including the omission of climate and other CO_2 related benefits that could not be monetized. The 2010 TSD discusses 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 impacts of CO_2 recognized in the literature, such as ocean acidification or potential tipping points, for various reasons, including the inherent difficulties in valuing non-market impacts and the fact that 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 emission reductions to inform the benefit-cost analysis. As previously noted, the IWG plans to seek

[133] The current version of the TSD is available at: *https://www.whitehouse.gov/sites/default/files/omb/inforeg/scc-tsd-final-july-2015.pdf.* The 2010 and 2013 TSDs present SC–CO_2 in 2007$ per metric ton. The estimates were adjusted to (1) Short tons for using conversion factor 0.90718474 and (2) 2011$ using Gross Domestic Product and Related Price Measures: Indexes and Percent Changes, *http://www.gpo.gov/fdsys/pkg/ECONI-2013-02/pdf/ECONI-2013-02-Pg3.pdf.*

independent expert advice on technical opportunities to improve the SC–CO_2 estimates from the Academies. The Academies' process will help to ensure that the SC–CO_2 estimates used by the federal government continue to reflect the best available science and methodologies. Additional details are provided in the TSDs.

The health co-benefits estimates represent the total monetized human health benefits for populations exposed to reduced $PM_{2.5}$ and ozone resulting from emission reductions from the federal plan approaches examined in the RIA for this proposal. Unlike the global SC–CO_2 estimates, the air pollution health co-benefits are estimated for the contiguous United States only. We used a ''benefit-per-ton'' approach to estimate the benefits of this rulemaking. To create the $PM_{2.5}$ benefit-per-ton estimates, we conducted air quality modeling for an illustrative scenario reflecting the proposed Clean Power Plan EGs to convert precursor emissions into changes in ambient $PM_{2.5}$ and ozone concentrations. We then used these air quality modeling results in BenMAP [134] to calculate average regional benefit-per-ton estimates using the health impact assumptions used in the PM NAAQS RIA [135] and Ozone NAAQS RIAs.[136] [137] The three regions were the Eastern United States, Western United States, and California. To calculate the co-benefits for this proposal, we multiplied the regional benefit-per-ton estimates generated from modeling of the proposed Clean Power Plan EGs standards by the corresponding regional emission reductions for this proposal.[138] All benefit-per-ton estimates reflect the geographic distribution of the modeled emissions for the proposed Clean Power Plan EGs, which may not exactly match the emission reductions in this proposed rulemaking, and thus they may not reflect the local variability in population density, meteorology, exposure, baseline health incidence rates, or other local factors for any specific location. More information regarding the derivation of the benefit-per-ton estimates is available in the Clean Power Plan Final Rule RIA.

PM benefit-per-ton values are generated using two concentration-response functions, Krewski et al. (2009) [139] and Lepeule et al. (2012).[140] These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effect estimates by particle type. Even though we assume that all fine particles have equivalent health effects, the benefit-per-ton estimates vary between $PM_{2.5}$ precursors depending on the location and magnitude of their impact on $PM_{2.5}$ concentrations, which drive population exposure.

It is important to note that the magnitude of the $PM_{2.5}$ and ozone co-benefits is largely driven by the concentration response functions for premature mortality and the value of a statistical life used to value reductions in premature mortality. For $PM_{2.5}$, we use two key empirical studies, one based on the American Cancer Society cohort study (Krewski et al., 2009) and one based on the extended Six Cities cohort study (Lepuele et al., 2012). The $PM_{2.5}$ co-benefits results are presented as a range based on benefit-per-ton estimates calculated using the concentration-response functions from these two epidemiology studies, but this range does not capture the full range of uncertainty inherent in the co-benefits estimates. In the RIA for this rule, which is available in the docket, we also include $PM_{2.5}$ co-benefits estimates using benefit-per-ton estimates based on expert judgments of the effect of $PM_{2.5}$ on premature mortality (Roman et al., 2008) [141] as a characterization of uncertainty regarding the $PM_{2.5}$-mortality relationship.

For the ozone co-benefits, we present the results as a range reflecting benefit-per-ton estimates which use several different concentration-response functions for mortality, with the lower end of the range based on a benefit-per-ton estimate using the function from Bell et al. (2004) [142] and the upper end based on a benefit-per-ton estimate using the function from Levy et al. (2005).[143] Similar to $PM_{2.5}$, the range of ozone co-benefits does not capture the full range of inherent uncertainty.

In this analysis, in estimating the benefits-per-ton for $PM_{2.5}$ precursors, the EPA assumes that the health impact function for fine particles is without a threshold. This is based on the conclusions of the EPA's *Integrated Science Assessment for Particulate Matter,*[144] which evaluated the substantial body of published scientific literature, reflecting thousands of epidemiology, toxicology, and clinical studies, that documents the association between elevated $PM_{2.5}$ concentrations and adverse health effects, including increased premature mortality. This assessment, which was twice reviewed by the EPA's independent Science Advisory Board, concluded that the scientific literature consistently finds that a no-threshold model most adequately portrays the PM-mortality concentration-response relationship.

In general, we are more confident in the magnitude of the risks we estimate from simulated $PM_{2.5}$ concentrations that coincide with the bulk of the observed PM concentrations in the epidemiological studies that are used to estimate the benefits. Likewise, we are less confident in the risk we estimate from simulated $PM_{2.5}$ concentrations

---

[134] *http://www.epa.gov/airquality/benmap/index.html.*

[135] U.S. Environmental Protection Agency (U.S. EPA). 2012. *Regulatory Impact Analysis for the Final Revisions to the National Ambient Air Quality Standards for Particulate Matter.* Research Triangle Park, NC: Office of Air Quality Planning and Standards, Health and Environmental Impacts Division. (EPA document number EPA–452/R–12–003, December 2012). Available at: *http://www.epa.gov/ttnecas1/regdata/RIAs/finalria.pdf.*

[136] U.S. Environmental Protection Agency (U.S. EPA). 2008b. Final Ozone NAAQS Regulatory Impact Analysis. Research Triangle Park, NC: Office of Air Quality Planning and Standards, Health and Environmental Impacts Division, Air Benefit and Cost Group Research. (EPA document number EPA–452/R–08–003, March 2008). Available at: *http://www.epa.gov/ttnecas1/regdata/RIAs/452_R_08_003.pdf.*

[137] U.S. Environmental Protection Agency (U.S. EPA). 2010. Section 3: Re-analysis of the Benefits of Attaining Alternative Ozone Standards to Incorporate Current Methods. Available at: *http://www.epa.gov/ttnecas1/regdata/RIAs/s3-supplemental_analysis-updated_benefits11-5.09.pdf.*

[138] U.S. Environmental Protection Agency. 2013. *Technical support document: Estimating the Benefit per Ton of Reducing $PM_{2.5}$ Precursors from 17 Sectors.* Research Triangle Park, NC: Office of Air and Radiation, Office of Air Quality Planning and Standards, January. Available at: *http://www.epa.gov/airquality/benmap/models/Source_Apportionment_BPT_TSD_1_31_13.pdf.*

[139] Krewski D.; M. Jerrett; R. T. Burnett; R. Ma; E. Hughes; Y. Shi, et al. 2009. *Extended Follow-up and Spatial Analysis of the American Cancer Society Study Linking Particulate Air Pollution and Mortality.* Health Effects Institute. (HEI Research Report number 140). Boston, MA: Health Effects Institute.

[140] Lepeule, J.; F. Laden; D. Dockery; J. Schwartz. 2012. ''Chronic Exposure to Fine Particles and Mortality: An Extended Follow-Up of the Harvard Six Cities Study from 1974 to 2009.'' *Environmental Health Perspective,* 120(7), July, pp. 965–970.

[141] Roman, H., et al. 2008. ''Expert Judgment Assessment of the Mortality Impact of Changes in Ambient Fine Particulate Matter in the U.S.'' *Environmental Science & Technology,* Vol. 42, No. 7, February, pp. 2268–2274.

[142] Bell, M.L., et al. 2004. ''Ozone and Short-Term Mortality in 95 U.S. Urban Communities, 1987–2000.'' *Journal of the American Medical Association,* 292(19), pp. 2372–8.

[143] Levy, J.I., S.M. Chemerynski, and J.A. Sarnat. 2005. ''Ozone Exposure and Mortality: An Empiric Bayes Metaregression Analysis.'' *Epidemiology.* 16(4): p. 458–68.

[144] U.S. Environmental Protection Agency. 2009. *Integrated Science Assessment for Particulate Matter (Final Report).* Research Triangle Park, NC: National Center for Environmental Assessment, RTP Division. (EPA document number EPA–600–R–08–139F, December 2009). Available at: *http://cfpub.epa.gov/si/si_public_record_Report.cfm?dirEntryId=216546.*

that fall below the bulk of the observed data in these studies.

For this analysis, policy-specific air quality data are not available,[145] and thus, we are unable to estimate the percentage of premature mortality associated with this specific rule that is above the lowest measured $PM_{2.5}$ levels (LML) for the two $PM_{2.5}$ mortality epidemiology studies that form the basis for our analysis. As a surrogate measure of mortality impacts above the LML, we provide the percentage of the population exposed above the LML in each of the two studies, using the estimates of baseline projected $PM_{2.5}$ from the air quality modeling for the proposed guidelines used to calculate the benefit-per-ton estimates for the EGU sector. Using the Krewski et al. (2009) study, 88 percent of the population is exposed to annual mean $PM_{2.5}$ levels at or above the LML of 5.8 micrograms per cubic meter (μg/m^3). Using the Lepeule et al. (2012) study, 46 percent of the population is exposed above the LML of 8 μg/m^3. It is important to note that baseline exposure is only one parameter in the health impact function, along with baseline incidence rates, population, and change in air quality.

Every benefit analysis examining the potential effects of a change in environmental protection requirements is limited, to some extent, by data gaps, model capabilities (such as geographic coverage), and uncertainties in the underlying scientific and economic studies used to configure the benefit and cost models. Despite these uncertainties, we believe the air quality co-benefit analysis for this rule provides a reasonable indication of the expected health benefits of the air pollution emission reductions for the illustrative analysis of this proposed action under a set of reasonable assumptions. This analysis does not include the type of detailed uncertainty assessment found in the 2012 $PM_{2.5}$ NAAQS RIA (U.S. EPA, 2012) because we lack the necessary air quality input and monitoring data to conduct a complete benefits assessment. In addition, using a benefit-per-ton approach adds another important source of uncertainty to the benefits estimates. The 2012 $PM_{2.5}$ NAAQS benefits analysis provides an indication of the sensitivity of our results to various assumptions.

We note that the monetized co-benefits estimates shown here do not include several important benefit categories, including exposure to SO_2, NO_X, and HAP (*e.g.,* mercury and hydrogen chloride), as well as ecosystem effects and visibility impairment. Although we do not have sufficient information or modeling available to provide monetized estimates for this rule, a qualitative assessment of these unquantified benefits is included in the RIA for this proposal. In addition, in the RIA for this proposal, we did not estimate changes in emissions of directly emitted particles. As a result, quantified $PM_{2.5}$ related benefits are underestimated by a relatively small amount. In the RIA for the proposed Clean Power Plan EGs, the benefits from reductions in directly emitted $PM_{2.5}$ were less than 10 percent of total monetized health co-benefits across all scenarios and years.

For more information on the benefits analysis, please refer to the RIA for this rule, which is available in the rulemaking docket.

IX. Community and Environmental Justice Considerations

In this section we provide an overview of the actions that the agency is taking to help ensure that vulnerable communities are not disproportionately impacted by this rulemaking.

As described in the Executive Summary, climate change is an EJ issue. Low-income communities and communities of color already overburdened with pollution are likely to be disproportionately affected by, and less resilient to, the impacts of climate change. This rulemaking will provide broad benefit to communities across the nation, as its purpose is to reduce GHGs, the most significant driver of climate change. While addressing climate change will provide broad benefits, it is particularly beneficial to low-income populations and some communities of color (in particular, populations defined jointly by ethnic/racial characteristics and geographic location) where people are most vulnerable to the impacts of climate change (a more robust discussion of the impacts of climate change on vulnerable communities is provided in the Executive Order 12898 discussion in section X.J of this preamble). While climate change is a global phenomenon, the adverse effects of climate change can be very localized, as impacts such as storms, flooding, and droughts are experienced in individual communities.

Vulnerable communities also often receive more than their fair share of conventional air pollution, with the attendant adverse health impacts.

The changes in electricity generation that will result from this rule will further benefit communities by reducing existing air pollution that directly contributes to adverse localized health effects. These air quality improvements will be achieved through this rule because the EGUs that emit the most GHGs also have the highest emissions of conventional pollutants, such as SO_2, NO_X, fine particles, and HAP. These pollutants are known to contribute to adverse health outcomes, including the development of heart and lung diseases, such as asthma and bronchitis, increased susceptibility to respiratory and cardiac symptoms, greater numbers of emergency room visits and hospital admissions, and premature deaths.[146] The EPA expects that the reductions in utilization of higher-emitting units likely to occur during the implementation of federal plans will produce significant reductions in emissions of conventional pollutants, particularly in those communities already overburdened by pollution, which are often low-income communities, communities of color, and indigenous communities. These reductions will have beneficial effects on air quality and public health, both locally and regionally. Further, this rulemaking complements other actions already taken by the EPA to reduce conventional pollutant emissions and improve health outcomes for overburdened communities.

By reducing millions of tons of CO_2 emissions that are contributing to global GHG levels and providing strong leadership to encourage meaningful reductions by countries across the globe, this rule is a significant step to address health and economic impacts of climate change that will fall disproportionately on vulnerable communities. By reducing millions of tons of conventional air pollutants, this proposed rule will lead to better air quality and improved health in those communities. In the comment period for the Clean Power Plan, we heard from many commenters who recognize and welcome those benefits.

There are other ways in which the actions that result from this rulemaking may affect overburdened communities in positive or potentially adverse ways and we also heard about these from commenters on the EGs.

While the agency expects overall emission decreases as a result of this rulemaking, we recognize that some EGUs may operate more frequently. To the extent that we project increases in utilization as a result of this rulemaking, we expect these increases to occur generally in lower-emitting NGCC units,

[145] In addition, site-specific emission reductions will depend upon how states implement the guidelines.

[146] Six Common Air Pollutants. *http://www.epa.gov/oaqps001/urbanair/.*

which have minimal or no emissions of SO_2 and HAP, lower emissions of particulate matter, and much lower emissions of NO_X compared to higher-emitting steam units. We acknowledge the concerns that have been raised on this point, but also the difficulty in anticipating prior to plan implementation where those impacts might occur. As described below, the EPA intends to conduct an assessment of whether and where emission increases may result from plan implementation and mitigate adverse impacts, if any, in overburdened communities.

In addition to the many positive anticipated health benefits of this rulemaking, it also will increase the use of clean energy and will encourage EE. These changes in the electricity generation system, which are already occurring, but may be accelerated by this program, are expected to have other positive benefits for communities. The electricity sector is, and will continue to be, investing more in RE and EE. The construction of renewable generation and the implementation of EE programs such as residential weatherization will bring investment and employment opportunities to the communities where they take place. It is important to ensure that all communities share in these benefits. And while we estimate that the benefits of this program will greatly exceed its costs (as noted in the RIA for this rulemaking), it is also important to ensure that to the extent there are increases in electricity costs, that those do not fall disproportionately on those least able to afford them.

The EPA has engaged with community groups throughout this rulemaking and we received many comments on the issues outlined above from community groups, EJ organizations, faith-based organizations, public health organizations, and others. This input has informed this proposed rulemaking and prompted the EPA to consider other steps that the agency can take in the short and long term to consider EJ and impacts to communities in federal plan development and implementation.

It has also prompted us to work with our federal partners to make sure that communities have information on federal resources available to assist them. We describe these resources below, as well as resources that the EPA will be providing to assist communities in accessing EE/RE and financial assistance programs.

Finally, and importantly, we recognize that communities must be able to participate meaningfully in the development of this rulemaking. In this section, we discuss the steps that the EPA will take to assist communities in engaging with the agency throughout the comment period of this rulemaking.

A. Proximity Analysis

The EPA is committed to ensuring that there is no disproportionate, adverse impact on overburdened communities as a result of this proposed rulemaking. To provide information fundamental to beginning that process, the EPA has conducted a proximity analysis for this proposed rulemaking that summarizes demographic data on the communities located near power plants.[147] The EPA understands that, in order to prevent disproportionately high and adverse human health or environmental effects on these communities, both the agency and communities must have information on the communities living near facilities, including demographic data, and that accessing and using census data files requires expertise that some community groups may lack. Therefore, the EPA used census data from the American Community Survey (ACS) 2008–2012 to conduct a proximity analysis that can be used by communities as they engage with the agency throughout the comment period of this rulemaking. The analysis and its results are presented in the EJ Screening Report for the Clean Power Plan, which is located in the docket for this rulemaking at EPA–HQ–OAR–2015–0199.

The proximity analysis provides detailed demographic information on the communities located within a 3-mile radius of each affected power plant in the United States. Included in the analysis is the breakdown by percentage of community characteristics such as income and minority status. The analysis shows a higher percentage of communities of color and low-income communities living near power plants than national averages. It is important to note that the impacts of power plant emissions are not limited to a 3-mile radius and the impacts of both potential increases and decreases in power plant emissions can be felt many miles away. Still, being aware of the characteristics of communities closest to power plants is a starting point in understanding how changes in the plant's air emissions may affect the air quality experienced by some of those already experiencing environmental burdens.

Although overall there is a higher fraction of communities of color and low-income populations living near power plants than national averages, there are differences between rural and urban power plants. There are many rural power plants that are located near small communities with high percentages of low-income populations and lower percentages of communities of color. In urban areas, nearby communities tend to be both low-income communities and communities of color. In light of this difference between rural and urban communities proximate to power plants and in order to adequately capture both the low-income and minority aspects central to environmental justice (EJ) considerations, we use the terms ''vulnerable'' or ''overburdened'' when referring to these communities. Our intent is for these terms to be understood in an expansive sense, in order to capture the full scope of communities, including indigenous communities most often located in rural areas, that are central to our EJ and community considerations.

As stated in the Executive Order 12898 discussion located in section X.J of this preamble, the EPA believes that all communities will benefit from this proposed rulemaking because this action directly addresses the impacts of climate change by limiting GHG emissions through the establishment of CO_2 emission standards for existing affected fossil fuel-fired power plants. The EPA also believes that the information provided in the proximity analysis will promote engagement between vulnerable communities and the agency throughout the rulemaking process. In addition to providing the proximity analysis in the docket of this rulemaking, the EPA will make it publicly available on its Clean Power Plan Communities Portal that will be linked to this rulemaking's Web site (*http://www.epa.gov/cleanpowerplan*). Furthermore, the EPA has also created an interactive mapping tool that illustrates where power plants are located and provides information on a state level. This tool is available at: *http://cleanpowerplanmaps.epa.gov/CleanPowerPlan/*.

B. Community Engagement in This Rulemaking Process

The EPA has heard from vulnerable communities throughout the outreach process for the Clean Power Plan that it is imperative for communities to have an understanding of how rulemakings that target climate change work. They expressed a desire to know how these programs may benefit their communities and what the potential adverse impacts of the rules may be on their communities. We intend to provide

[147] The proximity analysis was conducted using the EPA's environmental justice mapping and screening tool, EJSCREEN.

communities with the information that they need to engage with the agency throughout the comment period.

We have received feedback from communities that public hearings, webinars, and in-person meetings are the most effective ways to engage with them and to provide them with the information they need to understand the rulemaking process. Therefore, for this rulemaking, in addition to conducting public hearings for all members of the American public, the agency will hold a national webinar for communities in the early stages of the comment period. The goal of this webinar will be to walk communities through the highlights of the preamble, so they have an understanding of how the rulemaking may potentially affect their communities and they will have the contextual information they need to actively engage with the agency throughout the comment period.

Additionally, because we received positive feedback on the effectiveness of the face-to-face meetings conducted on the regional level, each region will be offering an outreach meeting(s) for communities. The goal of these meetings is to build a level of understanding on this rulemaking to enable vulnerable communities to actively engage with the agency throughout the comment period. Furthermore, we will follow up on common issues raised during the outreach meetings with national conference calls, specifically targeted for vulnerable communities.

C. Providing Communities With Access to Additional Resources

In section V.D of this preamble, we outline that we are seeking comment on whether a portion of this set-aside should be targeted to RE projects that benefit low-income communities. Furthermore, the EPA is seeking comment on how a low-income community should be defined as eligible under this set-aside. We also seek comment on how much of the set-aside should be designated as targeted at over-burdened communities. We also request comment on whether the methods of approval and distribution of allowances to projects that benefit low-income communities should differ, and if so, in what manner, from the methods that are proposed to apply to other RE projects.

As discussed below, there are also many federal programs that can help low-income populations access the benefits of RE and EE, and the economic benefits of a cleaner energy economy.

In the coming months, the EPA will continue to provide information and resources for low-income communities on existing federal, state, local, and other financial assistance programs to encourage EE/RE opportunities that are already available to communities. For example, the EPA will provide a catalog of current or recent state and local programs that have successfully helped communities adopt EE/RE measures. The goal of these resources is to help vulnerable communities gain the benefits of this rulemaking. The use of these RE/EE tools can also help low-income households reduce their electricity consumption and bills.

Additionally, as part of the resources that we will be providing low-income communities, the EPA will provide information on the Administration's Partnerships for Opportunity and Workforce and Economic Revitalization (POWER) Initative and other programs that specifically target economic development assistance to communities affected by changes in the coal industry and the utility power sector.[148]

D. Federal Programs and Resources Available to Communities

Federal agencies have a history of bringing EE and RE to low-income communities. Earlier this summer, the Administration announced a new initiative to scale up access to solar energy and cut energy bills for all Americans, in particular low- and moderate-income communities, and to create a more inclusive solar workforce. As part of this new initiative, the U.S. DOE, the U.S. Department of Housing and Urban Development, U.S. Department of Agriculture, and the EPA launched a National Community Solar Partnership to unlock access to solar energy for the nearly 50 percent of households and businesses that are renters or do not have adequate roof space to install solar systems, with a focus on low- and moderate-income communities. The Administration also set a goal to install 300 MW of RE in federally subsidized housing by 2020 and plants to provide technical assistance to make it easier to install solar energy on affordable housing, including clarifying how to use federal funding for EE and RE. To continue enhancing employment opportunities in the solar industry for all Americans, AmeriCorps is providing funding to deploy solar energy and create jobs in underserved communities, and DOE is working to expand solar energy education and opportunities for job training.

These recent announcements build on the many existing federal programs and resources available to improve EE and accelerate the deployment of RE in vulnerable communities. Some examples of these resources include: The DOE's Weatherization Assistance Program, Health and Human Service's Low-Income Home Energy Assistance Program, the Department of Agriculture's Energy Efficiency and Conservation Loan Program, High Cost Energy Grant Program, and the Rural Housing Service's Multi-Family Housing Program.

The U.S. Department of Housing and Urban Development supports EE improvements and the deployment of RE on affordable housing through its Energy Efficient Mortgage Program, Multifamily Property Assessed Clean Energy Pilot with the State of California, PowerSaver Program, and the use of Section 108 Community Development Block Grants. The Department of Treasury provides several tax credits to support RE development and EE in low-income communities, including the New Markets Tax Credit Program and the Low-Income Housing Tax Credit. The EPA's RE-Powering America's Land Initiative promotes the reuse of potentially contaminated lands, landfills and mine sites—many of which are in low-income communities—for RE through a combination of tailored redevelopment tools for communities and developers, as well as site-specific technical support. The EPA's Green Power Partnership is increasing community use of renewable electricity across the country and in low-income communities. The EPA partners with EE programs throughout the country that leverage ENERGY STAR to deliver broad consumer energy-saving benefits, of particular value to low-income households who can least afford high energy bills. ENERGY STAR also works with houses of worship to reduce energy costs—savings that can then be repurposed to their community mission, including programs and assistance to residents in low-income communities. The EPA will be working with these federal partners and others to ensure that states and vulnerable communities have access to information on these programs and their resources.

The federal government also has a number of programs to expand employment opportunities in the energy sector, including for underserved populations. Examples of these include the U.S. Department of Housing and Urban Development, DOE, and the Department of Education's ''STEM, Energy, and Economic Development'' program; DOE's Diversity in Science and Technology Advances National Clean Energy in Solar (DISTANCE-

[148] *http://www.eda.gov/power/.*

Solar) Program; Grid Engineering for Accelerated Renewable Energy Deployment (GEARED); the DOL's Trade Adjustment Assistance Community College and Career Training (TAACCCT), Apprenticeship USA Advancing Apprenticeships in the Energy Field, Job Corps Green Training and Greening of Centers, and YouthBuild; and the EPA's Environmental Workforce Development and Job Training (EWDJT) program.

E. Assessing Impacts of Federal Plan Implementation

It is important to the EPA that the implementation of federal plans be assessed in order to identify whether they cause any adverse impacts on communities already overburdened by disproportionate environmental harms and risks. The EPA will conduct its own assessment during the implementation phase of this rulemaking to determine whether the implementation of federal plans and other air quality rules are, in fact, reducing emissions and improving air quality in all areas and, or whether there are localized air quality impacts that need to be addressed under the Clean other CAA authorities.

The EPA will provide trainings for communities on resources that they can use to assess localized impacts, especially effects of co-pollutants, of plans on their communities. This training will include guidance in accessing the publicly available information that sources and states currently report that can help with ongoing assessments of federal plan impacts. For example, unit-specific emissions data and air quality monitoring data are readily available. This information, together with the assessment that the EPA will conduct in the implementation phase of this rulemaking will enable the agency and communities to monitor any disproportionate emissions that may result in adverse impacts and address them.

F. Co-Pollutants

Air quality in a given area is affected by emissions from nearby sources and may be influenced by emissions that travel hundreds of miles and mix with emissions from other sources.[149] In the CSAPR the EPA used its authority to reduce emissions that significantly contribute to downwind exposures. The RIA for the final CSAPR anticipates substantial health benefits for the population across a wide region. Similarly, the EPA believes that, like the CSAPR, this rulemaking will result in significant health benefits because it will reduce co-pollutant emissions of SO_2 and NO_X on a regional and national basis.[150] Thus, localized increases in NO_X emissions may well be more than offset by NO_X decreases elsewhere in the region that produce a net improvement in ozone and particulate concentrations across the area.

Another effect of the final CO_2 emission standards for affected existing fossil fuel-fired EGUs may be increased utilization of other, unmodified EGUs—in particular, high efficiency gas-fired EGUs—with relatively low GHG emissions per unit of electrical output. These plants may operate more hours during the year and could emit pollutants, including pollutants whose environmental effects would be localized and regional rather than global as is the case with GHG emissions. Changes in utilization already occur in response to energy demands and evolving energy sources, but the final CO_2 emission standards for affected existing fossil fuel-fired EGUs can be expected to cause more such changes. Increased utilization of solid fossil fuel-fired units generally would not increase peak concentrations of $PM_{2.5,}$ NO_X, or ozone around such EGUs to levels higher than those that are already occurring because peak hourly or daily emissions generally would not change; however, increased utilization may make periods of relatively high concentrations more frequent. It should be noted that the gas-fired sources likely to be dispatched more frequently have very low emissions of primary PM, $SO_{2,}$ and HAP per unit of electrical output and that they must continue to comply with other CAA requirements that directly address the conventional pollutants, including federal emission standards, rules included in SIPs, and conditions in title V operating permits, in addition to the guidelines in the final EGs rulemaking published elsewhere in this **Federal Register**. Therefore, local (or regional) air quality for these pollutants is not likely to be significantly affected. For natural gas-fired EGUs, the EPA found that regulation of HAP emissions ''is not appropriate or necessary because the impacts due to HAP emissions from such units are negligible based on the results of the study documented in the utility RTC.'' [151] Because gas-fired EGUs emit essentially no mercury, increased utilization will not increase methyl mercury concentrations in water bodies near these affected EGUs. In studies done by DOE/NETL comparing cost and performance of coal- and NGCC-fired generation, they assumed SO_2, NO_X, PM (and Hg) emissions to be ''negligible.'' Their studies predict NO_X emissions from a NGCC unit to be approximately 10 times lower than a subcritical or supercritical coal-fired boiler.[152] Many, although not all, NGCC units are also very well controlled for emissions of NO_X through the application of after combustion controls such as selective catalytic reduction.

G. The EPA's Continued Engagement

The EPA is committed to helping ensure that this action will not have disproportionate adverse human health or environmental effects on vulnerable communities. Throughout the implementation phase of this rulemaking, the agency will continue to provide trainings and resources to assist communities and as they engage with the agency. The EPA, through its outreach efforts during the comment period, will continue to solicit feedback from communities on what they would like additional trainings and resources on.

As described above, the EPA will assess the impacts of this rulemaking during its implementation. The EPA will house this assessment, along with the proximity analysis and other information generated throughout the implementation process, on its Clean Power Plan Communities Portal that will be linked to this rulemaking's Web site (*http://www.epa.gov/cleanpowerplan*). In addition, the EPA has expanded its set of resources that are being developed to help communities understand the breadth of policy options and programs that have successfully brought EE/RE to low-income communities. The EPA is committed to continuing its engagement with communities from the comment period of this rulemaking through federal plan implementation.

The EPA consulted its May 2015, *Guidance on Considering Environmental Justice During the Development of Regulatory Actions,* when crafting this rulemaking.[153] A more detailed discussion concerning the application of Executive Order 12898 in this rulemaking can be found in section X.J of this preamble. A summary of the EPA's interactions with communities is

[149] 76 FR 48348, August 11, 2011.

[150] *See* 76 FR 48347, August 11, 2011.

[151] 65 FR 79831, December 20, 2000.

[152] ''Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity'' Rev 2a, September 2013 Revision 2, November 2010 DOE/NETL–2010/1397.

[153] Guidance on Considering Environmental Justice During the Development of Regulatory Actions. *http://www.epa.gov/environmentaljustice/resources/policy/considering-ej-in-rulemaking-guide-final.pdf.* May 2015.

in the EJ Screening Report for the Clean Power Plan, available in the docket of this rulemaking. Furthermore, the EPA's responses to public comments, including comments received from communities, are provided in the response to comments documents located in the docket for this rulemaking.

In summary, the EPA in this proposed rulemaking has designed an integrative approach that helps to ensure that vulnerable communities are not disproportionately impacted by this rule. The proximity analysis that the agency has conducted is a central component of this approach. Not only is the proximity analysis a useful tool to help identify communities that may be impacted by this rulemaking; it will also help communities as they engage with the EPA throughout the comment period. It will help the EPA as we help low-income communities access EE/RE and financial assistance programs. Finally, in order to continue to ensure that overburdened communities are not disproportionately impacted by this rule, the EPA will be conducting an assessment during the implementation phase of the effects of this and other rules on air quality.

X. 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 proposed 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 for this rulemaking. The EPA prepared an analysis of the potential costs and benefits associated with this action. This analysis, which is contained in the ''Regulatory Impact Analysis for the Proposed Federal Plan Requirements for Greenhouse Gas Emissions from Electric Utility Generating Units Constructed on or Before January 8, 2014; Model Trading Rules; Amendments to Framework Regulations'' (EPA–452/R–15–006, July 2015), is available in the docket and is briefly summarized in section VIII of this preamble.

Consistent with Executive Order 12866 and Executive Order 13563, the EPA estimated the costs and benefits for two alternative federal plan approaches to implementing the proposed federal plan and model trading rules. The proposed action will achieve the same levels of emissions performance as required of state plans under the CAA section 111(d) EGs for the control of CO_2. Actions taken to comply with the guidelines will also reduce the emissions of directly-emitted $PM_{2.5}$, SO_2, and NO_X. The benefits associated with these $PM_{2.5}$, SO_2, and NO_X reductions are referred to as co-benefits, as these reductions are not the primary objective of this rule.

The RIA for this proposal analyzed two implementation scenarios, which we term the ''rate-based federal plan approach'' and the ''mass-based federal plan approach.'' It is very important to note that the differences between the analytical results for the rate-based and mass-based federal plan approaches presented in the RIA may not be indicative of likely differences between the approaches. In other words, if one approach performs differently than the other on a given metric during a given time period, this does not imply this will apply in all instances.

It is important to note that the potential regulatory impacts presented in the Clean Power Plan Final Rule RIA and the RIA for this proposed rule are not additive. Both RIAs present estimates of the benefits and costs of achieving the emission performance rates of the Clean Power Plan EGs. In the case of the Clean Power Plan Final Rule RIA, the illustrative analysis assumes the performance rates are met under state plans. In the case of this RIA for the proposed federal plan and model trading rules, the same performance rates are accomplished but are assumed to be achieved under the federal plan or model trading rules.

The EPA has used the social cost of carbon estimates presented in the *Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866 (May 2013, Revised July 2015)* (''current TSD'') to analyze CO_2 climate impacts of this rulemaking. We refer to these estimates, which were developed by the U.S. government, as ''SC–CO_2 estimates.'' The SC–CO_2 is an estimate of the monetary value of impacts associated with a marginal change in CO_2 emissions in a given year. The four SC–CO_2 estimates are associated with different discount rates (model average at 2.5 percent discount rate, 3 percent, and 5 percent; 95th percentile at 3 percent), and each increases over time. In this summary, the EPA provides the estimate of climate benefits associated with the SC–CO_2 value deemed to be central in the current TSD: The model average at 3 percent discount rate.

The EPA estimates that, in 2020, this proposal will yield monetized climate benefits (in 2011$) of approximately $2.8 billion for the rate-based approach and $3.3 billion for the mass-based approach (3 percent model average). For the rate-based approach, the air pollution health co-benefits in 2020 are estimated to be $0.7 billion to $1.8 billion (2011$) for a 3 percent discount rate and $0.64 billion to $1.7 billion (2011$) for a 7 percent discount rate. For the mass-based approach, the air pollution health co-benefits in 2020 are estimated to be $2.0 billion to $4.8 billion (2011$) for a 3 percent discount rate and $1.8 billion to $4.4 billion (2011$) for a 7 percent discount rate. The annual compliance costs estimated by IPM and inclusive of DS–EE program and participant costs and monitoring, reporting, and recordkeeping costs in 2020, are approximately $2.5 billion for the rate-based approach and $1.4 billion for the mass-based approach (2011$). The quantified net benefits (the difference between monetized benefits and compliance costs) in 2020 are estimated to range from $1.0 billion to $2.1 billion (2011$) for the rate-based approach and from $3.9 billion to $6.7 billion (2011$) for the mass-based approach, using a 3 percent discount rate (model average).

The EPA estimates that, in 2025, the proposal will yield monetized climate benefits (in 2011$) of approximately $10 billion for the rate-based approach and $12 billion for the mass-based approach (3 percent model average). For the rate-based approach, the air pollution health co-benefits in 2025 are estimated to be $7.4 billion to $18 billion (2011$) for a 3 percent discount rate and $6.7 billion to $16 billion (2011$) for a 7 percent discount rate. For the mass-based approach, the air pollution health co-benefits in 2025 are estimated to be $7.1 billion to $17 billion (2011$) for a 3 percent discount rate and $6.5 billion to $16 billion (2011$) for a 7 percent discount rate. The annual compliance costs estimated by IPM and inclusive of DS–EE program and participant costs and MRR costs in 2025, are approximately $1.0 billion for the rate-based approach and $3.0 billion for the mass-based approach (2011$). The quantified net benefits (the difference between monetized benefits and compliance costs) in 2025 are estimated to range from $17 billion to $27 billion (2011$) for the rate-based approach and $16 billion to $26 billion (2011$) for the mass-based approach, using a 3 percent discount rate (model average).

The EPA estimates that, in 2030, the proposal will yield monetized climate benefits (in 2011$) of approximately $20 billion for the rate-based approach and $20 billion for the mass-based approach (3 percent model average). For the rate-based approach, the air pollution health co-benefits in 2030 are estimated to be $14 billion to $34 billion (2011$) for a 3 percent discount rate and $13 billion to $31 billion (2011$) for a 7 percent discount rate. For the mass-based approach, the air pollution health co-benefits in 2030 are estimated to be $12 billion to $28 billion (2011$) for a 3 percent discount rate and $11 billion to $26 billion (2011$) for a 7 percent discount rate. The annual compliance costs estimated by IPM and inclusive of DS–EE program and participant costs and monitoring, reporting, and recordkeeping costs in 2030, are approximately $8.4 billion for the rate-based approach and $5.1 billion for the mass-based approach (2011$). The quantified net benefits (the difference between monetized benefits and compliance costs) in 2030 are estimated to range from $26 billion to $45 billion (2011$) for the rate-based approach and from $26 billion to $43 billion (2011$) for the mass-based approach, using a 3 percent discount rate (model average).

Table 18 and Table 19 of this preamble provide the estimates of the climate benefits, health co-benefits, compliance costs and net benefits of the proposal for rate-based and mass-based federal plan approaches, respectively.

TABLE 18—SUMMARY OF THE MONETIZED BENEFITS, COMPLIANCE COSTS, AND NET BENEFITS FOR THE PROPOSAL IN 2020, 2025 AND 2030 UNDER THE RATE-BASED FEDERAL PLAN APPROACH

[Billions of 2011$] [a]

	Rate-Based Approach					
	2020		2025		2030	
Climate Benefits [b]						
5% discount rate	$0.80		$3.1		$6.4	
3% discount rate	$2.8		$10		$20	
2.5% discount rate	$4.1		$15		$29	
95th percentile at 3% discount rate	$8.2		$31		$61	
Air Quality Co-Benefits Discount Rate						
	3%	7%	3%	7%	3%	7%
Air Quality Health Co-benefits [c]	$0.70 to $1.8	$0.64 to $1.7	$7.4 to $18	$6.7 to $16	$14 to $34	$13 to $31
Compliance Costs [d]	$2.5		$1.0		$8.4	
Net Benefits [e]	$1.0 to $2.1	$1.0 to $2.0	$17 to $27	$16 to $25	$26 to $45	$25 to $43
Non-Monetized Benefits	Non-monetized climate benefits. Reductions in exposure to ambient NO_2 and SO_2. Reductions in mercury deposition. Ecosystem benefits associated with reductions in emissions of NO_X, SO_2, PM, and mercury. Visibility impairment.					

[a] All are rounded to two significant figures, so figures may not sum.

[b] The climate benefit estimate in this summary table reflects global impacts from CO_2 emission changes and does not account for changes in non-CO_2 GHG emissions. Also, different discount rates are applied to SC–CO_2 than to the other estimates because CO_2 emissions are long-lived and subsequent damages occur over many years. The benefit estimates in this table are based on the average SC–CO_2 estimated for a 3 percent discount rate. However, we emphasize the importance and value of considering the full range of SC–CO_2 values. As shown in the RIA, climate benefits are also estimated using the other three SC–CO_2 estimates (model average at 2.5 percent discount rate, 3 percent, and 5 percent; 95th percentile at 3 percent). The SC–CO_2 estimates are year-specific and increase over time.

[c] The air pollution health co-benefits reflect reduced exposure to $PM_{2.5}$ and ozone associated with emission reductions of SO_2 and NO_X. The range reflects the use of concentration-response functions from different epidemiology studies. The co-benefits do not include the benefits of reductions in directly emitted $PM_{2.5}$. These additional benefits would increase overall benefits by a few percent based on the analyses conducted for the Clean Power Plan proposed rule. The reduction in premature fatalities each year accounts for over 98 percent of total monetized co-benefits from $PM_{2.5}$ and ozone. These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effect estimates by particle type.

[d] Costs are approximated by the compliance costs estimated using the IPM for this proposal and a discount rate of approximately 5 percent. This estimate includes monitoring, recordkeeping, and reporting costs and DS–EE program and participant costs.

[e] The estimates of net benefits in this summary table are calculated using the global SC–CO_2 at a 3 percent discount rate (model average). The RIA includes combined climate and health estimates based on additional discount rates.

TABLE 19—SUMMARY OF THE MONETIZED BENEFITS, COMPLIANCE COSTS, AND NET BENEFITS FOR THE PROPOSAL IN 2020, 2025 AND 2030 UNDER THE MASS-BASED FEDERAL PLAN APPROACH

[Billions of 2011$] [a]

	Mass-Based Approach					
	2020		2025		2030	
Climate Benefits [b]						
5% discount rate	$0.9		$3.6		$6.4	
3% discount rate	$3.3		$12		$20	
2.5% discount rate	$4.9		$17		$29	
95th percentile at 3% discount rate	$9.7		$35		$60	
Air Quality Co-Benefits Discount Rate						
	3%	7%	3%	7%	3%	7%
Air Quality Health Co-benefits [c]	$2.0 to $4.8	$1.8 to $4.4	$7.1 to $17	$6.5 to $16	$12 to $28	$11 to $26
Compliance Costs [d]	$1.4		$3.0		$5.1	
Net Benefits [e]	$3.9 to $6.7	$3.7 to $6.3	$16 to $26	$15 to $24	$26 to $43	$25 to $40
Non-Monetized Benefits	Non-monetized climate benefits. Reductions in exposure to ambient NO_2 and SO_2. Reductions in mercury deposition. Ecosystem benefits associated with reductions in emissions of NO_X, SO_2, PM, and mercury. Visibility improvement.					

[a] All are rounded to two significant figures, so figures may not sum.

[b] The climate benefit estimate in this summary table reflects global impacts from CO_2 emission changes and does not account for changes in non-CO_2 GHG emissions. Also, different discount rates are applied to SC–CO_2 than to the other estimates because CO_2 emissions are long-lived and subsequent damages occur over many years. The benefit estimates in this table are based on the average SC–CO_2 estimated for a 3 percent discount rate. However, we emphasize the importance and value of considering the full range of SC–CO_2 values. As shown in the RIA, climate benefits are also estimated using the other three SC–CO_2 estimates (model average at 2.5 percent discount rate, 3 percent, and 5 percent; 95th percentile at 3 percent). The SC–CO_2 estimates are year-specific and increase over time.

[c] The air pollution health co-benefits reflect reduced exposure to $PM_{2.5}$ and ozone associated with emission reductions of SO_2 and NO_X. The co-benefits do not include the benefits of reductions in directly emitted $PM_{2.5}$. These additional benefits would increase overall benefits by a few percent based on the analyses conducted for the Clean Power Plan proposed rule. The range reflects the use of concentration-response functions from different epidemiology studies. The reduction in premature fatalities each year accounts for over 98 percent of total monetized co-benefits from $PM_{2.5}$ and ozone. These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effect estimates by particle type.

[d] Costs are approximated by the compliance costs estimated using IPM for this proposal and a discount rate of approximately 5 percent. This estimate includes monitoring, recordkeeping, and reporting costs and DS–EE program and participant costs.

[e] The estimates of net benefits in this summary table are calculated using the global SC–CO_2 at a 3 percent discount rate (model average). The RIA includes combined climate and health estimates based on additional discount rates.

There are additional important benefits that the EPA could not monetize. Due to current data and modeling limitations, our estimates of the benefits from reducing CO_2 emissions do not include important impacts like ocean acidification or potential tipping points in natural or managed ecosystems. Unquantified benefits also include climate benefits from reducing emissions of non-CO_2 GHGs (*e.g.,* nitrous oxide and methane) and co-benefits from reducing direct exposure to SO_2, NO_X, and HAP (*e.g.,* mercury), as well as from reducing ecosystem effects and visibility impairment. Based upon the foregoing discussion, it remains clear that the benefits of this proposed action are substantial, and far exceed the costs. Additional details on benefits, costs, and net benefits estimates are provided in the RIA for this proposal.

B. Paperwork Reduction Act (PRA)

The information collection requirements in this rule have been submitted for approval to OMB under the PRA. The Information Collection Request (ICR) document prepared by the EPA has been assigned EPA ICR number *2526.01.* You can find a copy of the ICR in the docket for this rule, and it is briefly summarized here. The information collection requirements are not enforceable until approved by OMB.

This rule does not directly impose specific requirements on state and U.S. territory governments with affected EGUs. The rule also does not impose specific requirements on tribal governments that have affected EGUs located in their area of Indian country. This rule does impose specific requirements on affected EGUs located in states, U.S. territories, or areas of Indian country.

The information collection activities in this proposed rule are consistent with those activities defined under the Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units (*i.e.,* the Clean Power Plan) finalized on August 3, 2015. The information collection requirements in this proposed rule have been submitted for approval to the Office of Management and Budget (OMB) under the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.* The ICR document prepared by the EPA has been assigned EPA ICR number 2526.01. You can find a copy of the ICR in the docket for this rule, and it is briefly summarized here.

Aside from reading and understanding the rule, this proposed action would impose minimal new information collection burden on affected EGUs beyond what those affected EGUs would already be subject to under the authorities of 40 CFR parts 75 and 98. OMB has previously approved the information collection requirements contained in the existing part 75 and 98 regulations (40 CFR part 75 and 40 CFR part 98) under the provisions of the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.* and has assigned OMB control numbers 2060–0626 and 2060–0629, respectively. Apart from certain reporting costs based on requirements in the NSPS General Provisions (40 CFR part 60, subpart A), which are mandatory for all owners/operators subject to CAA section 111 national emission standards, there are no new information collection costs, as the information required by this proposed rule is already collected and reported by other regulatory programs. The recordkeeping and reporting requirements are specifically authorized by CAA section 114 (42 U.S.C. 7414). All information submitted to the EPA pursuant to the recordkeeping and reporting requirements for which a claim of confidentiality is made is safeguarded according to agency policies set forth in 40 CFR part 2, subpart B.

Although the EPA cannot determine at this time how many affected EGU respondents will submit information under the federal plan, the EPA has estimated an ''upper bound'' burden estimate for this ICR that estimates burden should every affected EGU read and understand the rule. This is the only potential respondent activity that would be required under the 3-year period following publication of the final federal plan, as there are no obligations to respond in this period. The results of this upper bound estimate of federal plan burden are presented below:

Respondents/affected entities: 1,028.

Respondents' obligation to respond: Not applicable, no responses are required during the period covered by the ICR.

Estimated number of respondents: Unknown at this time, but have assumed all affected entities are respondents for an upper bound estimate.

Frequency of response: None, no responses are required during the period covered by the ICR.

Total estimated burden: 17,133 hours (per year). Burden is defined at 5 CFR 1320.3(b).

Total estimated cost: $1,706,501 (per year).

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 *oria_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 23, 2015. The EPA will respond to any ICR-related comments in the final rule.

C. Regulatory Flexibility Act (RFA)

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 within the RIA in docket EPA–HQ–OAR–2015–0199 and is summarized here.

The small entities subject to the requirements of this proposed rule may include privately-owned and publicly-owned entities, and rural electric cooperatives that are majority owners of affected EGUs. The EPA conducted this regulatory flexibility analysis at the highest level of ownership, evaluating parent entities with the largest share of ownership in at least one potentially-affected EGU included in EPA's Base Case using the IPM v.5.15, used in the RIA for this proposed rule. This analysis drew on parsed unit-level estimates using IPM results for 2030.

The EPA identified 223 potentially affected EGUs owned by 74 small entities included in 2030 projections from EPA's IPM v.5.15. Fifty-nine of these potentially affected EGUs are projected to no longer be operating by 2030 in the Base Case of EPA's version of IPM. Twenty-four small entities are projected to have all of their potentially affected EGUs cease operation by 2030 in this base case.

The EPA estimated net compliance costs for individual EGUs for the proposed rule using components for operating and annualized capital costs, fuel costs, demand-side energy efficiency program costs, and revenue changes. This approach is consistent with previous proposed power sector regulations, but also adds the additional component of change in demand-side energy efficiency program costs. Investment in demand-side energy efficiency results in lower electricity demand, and consequently fewer emissions as production is reduced to meet the lower demand, an important emission-reduction strategy modeled in the rate-based and mass-based federal plan approaches. For this analysis, the EPA used the parsed unit-level estimates to estimate three of the four components of the net compliance cost equation using IPM outputs: The change in operating and annualized capital costs, the change in fuel costs, and the change in revenue, where all changes are estimated as the difference between the base case and federal plan scenario. These impacts were then summed for each small entity, adjusting for ownership share. An additional analysis was performed outside of EPA's IPM model to estimate the change in demand-side energy efficiency program costs, based largely on IPM-projected outputs.

As noted earlier, there are 74 small entities with potentially affected EGUs that are modeled in the IPM base case in 2030. Of these, 24 small entities are projected to withdraw all of their potentially affected EGUs from operation under base case conditions. This leaves 50 small entities with potentially affected EGUs that are projected to be generating electricity in 2030. Under the rate-based federal plan approach, 7 of these 50 small entities are projected to withdraw all of their potentially affected EGUs from operation by 2030. Under the mass-based federal plan approach, 5 of these 50 small entities are projected withdraw all of their potentially affected EGUs from operation by 2030.

Under the rate-based federal plan approach, 23 small entities are projected to incur net compliance costs greater than 3 percent of generation revenues from their potentially affected EGUs. In contrast, 9 entities are estimated to have net compliance cost savings greater than 3 percent of their generation revenues from affected EGUs. Under the mass-based federal plan approach, 21 small entities are projected to incur net compliance costs greater than 3 percent of generation revenues from their potentially affected EGUs. In contrast, 11 entities are estimated to have net compliance cost savings greater than 3 percent of generation revenues from their affected EGUs.

There are uncertainties and limitations in this analysis that may result in estimates that diverge from what we might see in reality. For example, at the time of this proposal, the EPA has no information on whether any or how many states will require a federal plan. The rate-based and mass-based federal plan approaches analyzed in this IRFA are based on a scenario where all states of the contiguous United States will be regulated under a federal plan. Another factor to consider is that entities operating in regulated or cost-of-service markets are likely able to recover compliance costs through rate adjustments; as a result these costs can be viewed as likely being over-estimates for this set of utilities. Other uncertainties and data limitations exist and are described in the complete IRFA available for review within the RIA for this proposal.

As discussed earlier in this preamble, the reporting, recordkeeping and other compliance requirements are most likely covered under 40 CFR part 75 and part 98 programs for affected EGUs. Therefore, only a marginal additional cost is expected for the monitoring, reporting and recordkeeping requirements of the proposed federal plan for affected EGUs.

Owners of affected EGUs may be subject to other related rules. For example, on September 20, 2013, the EPA proposed carbon pollution standards for new fossil fuel fired EGUs. On June 2, 2014, the EPA proposed carbon pollution standards for modified and reconstructed fossil fuel-fired EGUs, in addition to the Clean Power Plan EGs, to cut carbon pollution from existing fossil fuel-fired EGUs. These existing EGUs are, or will be, potentially impacted by several other recently finalized EPA rules. On February 16, 2012, the EPA issued the mercury and air toxics standards (MATS) rule (77 FR 9304) to reduce emissions of toxic air pollutants from new and existing coal- and oil-fired EGUs. On May 19, 2014, the EPA issued a final rule under section 316(b) of the Clean Water Act (33 U.S.C. 1326(b)). This rule establishes new standards to reduce injury and death of fish and other aquatic life caused by cooling water intake structures at existing power plants and manufacturing facilities. On June 18, 2014 (79 FR 34830), the EPA promulgated the stream electric effluent limitation guidelines (SE ELG) rule to strengthen the controls on discharges from certain steam electric power plants. On April 17, 2015 (80 FR 21302), the EPA promulgated the coal combustion residuals (CCR) rule, which establishes technical requirements for CCR landfills and surface impoundments under subtitle D of the Resource Conservation and Recovery Act (RCRA), the nation's primary law for regulating solid waste.

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.

The EPA also considered whether the separate changes that we are proposing to make, as explained in section VII of this preamble, to the framework regulations in subpart B of part 60 of the CAA regulations would have any impacts on small entities. Since these changes only modify and enhance the procedures that the Administrator will follow in processing state plans and promulgating a federal plan, and do not alter the rules or requirements that states or regulated entities must follow, the agency does not believe that there will be economic impacts on small entities from this portion of this proposal. After considering the economic impacts of the proposed changes to 40 CFR 60.27, I certify those changes will not have a significant economic impact on a substantial number of small entities.

D. Unfunded Mandates Reform Act (UMRA)

This action contains a federal mandate under UMRA, 2 U.S.C. 1531–1538, that could potentially result in expenditures of $100 million or more for state, local, and tribal governments, in the aggregate, or the private sector in any 1 year. This federal plan will apply only to those affected EGUs located in states that do not submit approvable state plans, which is a subset of the EGUs considered in the RIA for the final EGs (see RIA for this proposal for further discussion of impacts). Because it is impossible to determine at this time which states might be ultimately subject to a federal plan, the EPA cannot determine whether this rule, when finalized, will be subject to UMRA. However, as noted below, the agency has done substantial outreach to government entities as part of both the federal plan and the related CAA section 111(d) rulemaking. Further, regardless of whether the EPA does determine that this action ultimately meets the UMRA threshold, the agency intends to do additional outreach with government entities between now and the final rule. Additionally, the EPA has determined that this action is not subject to the requirements of section 203 of UMRA because it contains no regulatory requirements that might significantly or uniquely affect small governments.

Nevertheless, the EPA is aware that there is substantial interest in this rule among small entities (*e.g.,* municipal and rural electric cooperatives). In light of this interest, prior to this action, the EPA sought early input from representatives of small entities while formulating the provisions of the proposed regulation. Such outreach is also consistent with the President's January 18, 2011 Memorandum on Regulatory Flexibility, Small Business, and Job Creation, which emphasizes the important role small businesses play in the American economy. This outreach process has enabled the EPA to hear directly from these representatives, as the EPA developed the rule about how the EPA should approach the complex question of how to apply section 111 of the CAA to the regulation of GHGs from these source categories. We invite comments on all aspects of this proposal and its impacts, including potential adverse impacts, on small entities.

E. Executive Order 13132: Federalism

The EPA believes that this proposed rule may be of significant interest to state and local governments due to its relationship with the Clean Power Plan EGs. Therefore, the EPA has determined that consultations with state and local governments conducted during the Clean Power Plan EGs development process are also relevant to this proposed rule. Consistent with the EPA's policy to promote communications between the EPA and state and local governments, the EPA consulted with state and local officials early in the process of developing the Clean Power Plan EGs to permit them to have meaningful and timely input into its development. As described in the Federalism discussion in the preamble to the proposed standards of performance for GHG emissions from new EGUs (79 FR 1501; January 8, 2014), the EPA consulted with state and local officials in the process of developing the proposed standards for newly constructed EGUs. A detailed Federalism Summary Impact Statement (FSIS) describing the most pressing issues raised in pre-proposal and post-proposal comments will be forthcoming with the final Clean Power Plan EGs, as required by section 6(b) of Executive Order 13132. In the spirit of Executive Order 13132, and consistent with the EPA's policy to promote communications between the EPA and state and local governments, the EPA specifically solicits comment on this proposed action from state and local officials.

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

This proposed action has tribal implications. However, it will neither impose substantial direct compliance costs on federally recognized tribal governments, nor preempt tribal law. The EGUs potentially impacted by this proposed rulemaking located on Indian reservations are primarily owned by private entities, and in one case, partially owned by an agency of the U.S. government. As a result, the tribes on whose areas of Indian country those units are located will not be directly impacted by any costs of complying with this proposed rulemaking incurred by the owners/operators of those units. There would only be tribal implications in regards to compliance costs associated with this proposed rulemaking in the case where a tribal government has an ownership interest in a potentially affected EGU. A tribal government could also incur costs in the event that it seeks and is given delegated authority to enforce the federal plan proposed in this rulemaking. The EPA has, nevertheless, offered consultation to the tribes on whose areas of Indian country the units are located. As part of its general outreach to tribes regarding this proposed rulemaking, the EPA received feedback from a number of tribes regarding the potential overall economic impact that both the proposed Clean Power Plan and a proposed federal plan rulemaking may have on them. In these instances, the EPA has reached out to these tribes and as part of the consultation on the Clean Power Plan engaged with them on their concerns regarding a potential federal plan.

The EPA has conducted consultation with tribes on the Clean Power Plan and the Supplemental Proposal for the Clean Power Plan and will offer all tribes consultation on this proposed action. The EPA held consultations with tribes on the Clean Power Plan in the fall of 2014 before the agency issued its Supplemental Proposal for Indian country and U.S. Territories. Additionally, the EPA held consultations for tribes shortly following the release of the supplemental proposal. The agency also held a public hearing on the supplemental proposal on November 19, 2014, in Phoenix, Arizona. At the public hearing the agency received oral comments from community members representing a number of tribes and a number of tribal officials. The agency also conducted consultations with tribes in the spring and summer of 2015. An overview of the consultations provided as part of the Clean Power Plan is available in section XII.F of the final EGs.

Additionally, the EPA engaged in meaningful dialogue with tribal stakeholders to obtain their feedback in the pre-proposal stages of this rulemaking. We provided an update on this proposed rulemaking on the May 28, 2015, National Tribal Air Association and the EPA Air Policy call. Staff attended the National Tribal Forum conference on May 20, 2015 and provided an overview of the Clean Power Plan and explained that the agency would be proposing a federal plan.

Consistent with previous rulemakings impacting the power sector, there is significant tribal interest in these rulemakings because of the potential indirect impacts that rules such as the Clean Power Plan and this proposed federal plan may have on tribes. The EPA specifically solicits additional feedback from tribal officials on all aspects of this proposed rulemaking, including whether tribes whose areas of Indian country contain affected EGU(s) are interested in developing their own plan implementing the final EGs. Additionally, tribal stakeholders will be included in the outreach that the agency will be conducting with those communities already overburdened by pollution, which are often low-income communities, communities of color, and indigenous communities. The actions that the agency will be taking are outlined in section IX of this preamble.

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

The EPA interprets EO 13045 (62 FR 19885; April 23, 1997) as applying to those regulatory actions that concern health or safety risks, such that the analysis required under section 5–501 of the Order has the potential to influence the regulation. This action is not subject to EO 13045 because it does not involve decisions on environmental health or safety risks that may disproportionately affect children. The EPA believes that the CO_2 emission reductions resulting from implementation of the proposed federal plan, as well as substantial ozone and $PM_{2.5}$ emission reductions as a cobenefit, would further improve children's health.

H. Executive Order 13211: Actions That Significantly Affect Energy Supply, Distribution, or Use

This action, which is a significant regulatory action under EO 12866, is likely to have a significant effect on the supply, distribution, or use of energy. The EPA has prepared a Statement of Energy Effects for this action as follows. We estimate a 1 to 2 percent change in retail electricity prices on average across the contiguous United States in 2025, and a 22 to 23 percent reduction in coal-fired electricity generation as a result of this rule. The EPA projects that utility power sector delivered natural gas prices will increase by up to 2.5 percent in 2030. For more information on the estimated energy effects, please refer to the economic impact analysis for this proposal. The analysis is available in the RIA, which is in the public docket.

I. National Technology Transfer and Advancement Act (NTTAA) and 1 CFR Part 51

This proposed action involves technical standards. The EPA proposes to recognize ANSI accreditation under ISO 14065 for GHG validation and verification bodies as a component of accreditation of independent verifiers under both proposed federal plan approachs. The EPA also proposes that net energy output measurements must be performed using 0.2 accuracy class electricity metering instrumentation and calibration procedures as specified under ANSI Standards No. C12.20.

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

Executive Order 12898 (59 FR 7629; February 16, 1994) establishes federal executive policy on environmental justice (EJ). Its main provision directs federal agencies, to the greatest extent practicable and permitted by law, to make EJ part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations and low-income populations in the United States. The EPA defines EJ as the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies. The EPA has this goal for all communities and persons across this Nation. It will be achieved when everyone enjoys the same degree of protection from environmental and health hazards and equal access to the decision-making process to have a healthy environment in which to live, learn, and work.

Leading up to this rulemaking the EPA summarized the public health and welfare effects of GHG emissions in its 2009 Endangerment Finding. As part of the Endangerment Finding, the Administrator considered climate change risks to minority populations and low-income populations, finding that certain parts of the population may be especially vulnerable based on their characteristics or circumstances. Populations that were found to be particularly vulnerable to climate change risks include the poor, the elderly, the very young, those already in poor health, the disabled, those living alone, and/or indigenous populations dependent on one or a few resources. See sections X.F and X.G of this preamble, above, where the EPA discusses Consultation and Coordination with Tribal Governments and Protection of Children. The Administrator placed weight on the fact that certain groups, including children, the elderly, and the poor, are most vulnerable to climate-related health effects.

The record for the 2009 Endangerment Finding summarizes the strong scientific evidence in the major assessment reports by the U.S. Global Change Research Program, the Intergovernmental Panel on Climate Change (IPCC), and the National Research Council of the National Academies that the potential impacts of climate change raise EJ issues. These reports concluded that poor communities can be especially vulnerable to climate change impacts because they tend to have more limited adaptive capacities and are more dependent on climate-sensitive resources such as local water and food supplies. In addition, Native American tribal communities possess unique vulnerabilities to climate change, particularly those impacted by degradation of natural and cultural resources within established reservation boundaries and threats to traditional subsistence lifestyles. Tribal communities whose health, economic well-being, and cultural traditions that depend upon the natural environment will likely be affected by the degradation of ecosystem goods and services associated with climate change. The 2009 Endangerment Finding record also specifically noted that Southwest native cultures are especially vulnerable to water quality and availability impacts. Native Alaskan communities are already experiencing disruptive impacts, including coastal erosion and shifts in the range or abundance of wild species crucial to their livelihoods and well-being.

The most recent assessments continue to strengthen scientific understanding of climate change risks to minority populations and low-income populations in the United States.[154] The new assessment literature provides more detailed findings regarding these populations' vulnerabilities and projected impacts they may experience. In addition, the most recent assessment reports provide new information on how some communities of color may be uniquely vulnerable to climate change health impacts in the United States. These reports find that certain climate change related impacts—including heat waves, degraded air quality, and extreme weather events—have disproportionate effects on low-income populations and some communities of color (in particular, populations defined jointly by ethnic/racial characteristics and geographic location), raising EJ concerns. Existing health disparities and other inequities in these communities increase their vulnerability to the health effects of climate change. In addition, assessment reports also find that climate change poses particular threats to health, well-being, and ways of life of indigenous peoples in the United States.

As the scientific literature presented above and as the 2009 Endangerment Finding illustrates, low-income populations and some communities of color are especially vulnerable to the health and other adverse impacts of climate change. The EPA believes that communities will benefit from this proposed federal plan because this action directly addresses the impacts of climate change by limiting GHG emissions through the establishment of CO_2 emission standards for existing affected fossil fuel-fired EGUs.

In addition to reducing CO_2 emissions, the guidelines finalized in this rulemaking would reduce other emissions from affected EGUs that reduce generation due to higher adoption of EE and RE. These emission reductions will include SO_2 and NO_X, which form ambient $PM_{2.5}$ and ozone in the atmosphere, and HAP, such as mercury and hydrochloric acid. In the final rule revising the annual $PM_{2.5}$ NAAQS,[155] the EPA identified low-income populations as being a vulnerable population for experiencing adverse health effects related to PM exposures. Low-income populations have been generally found to have a higher prevalence of pre-existing diseases, limited access to medical treatment, and increased nutritional deficiencies, which can increase this population's susceptibility to PM-related effects.[156] In areas where this rulemaking reduces exposure to $PM_{2.5}$, ozone, and methylmercury, low-income populations will also benefit from such emission reductions. The RIA for this rulemaking, included in the docket for this rulemaking, provides additional information regarding the health and ecosystem effects associated with these emission reductions.

Additionally, as outlined in the community and EJ considerations section IX of this preamble, the EPA has taken a number of actions to help ensure that this action will not have potential disproportionately high and adverse human health or environmental effects on vulnerable communities. The EPA consulted its May 2015, *Guidance on Considering Environmental Justice During the Development of Regulatory Actions,* when determining what actions to take.[157] As described in section IX of this preamble (community and EJ considerations), the EPA also conducted a proximity analysis, which is available in the docket of this rulemaking and is discussed in section IX of this preamble. Additionally, as outlined in sections I and IX of this preamble the EPA has

[154] 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, 841 pp.

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, 1132 pp.

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, 688 pp.

[155] "National Ambient Air Quality Standards for Particulate Matter, Final Rule," 78 FR 3086 (January 15, 2013).

[156] U.S. Environmental Protection Agency (U.S. EPA). 2009. *Integrated Science Assessment for Particulate Matter (Final Report).* EPA–600–R–08–139F. National Center for Environmental Assessment—RTP Division. December. Available on the Internet at *http://www.cfpub.epa.gov/si/si_public_record_Report.cfm?dirEntryId=216546.*

[157] Guidance on Considering Environmental Justice During the Development of Regulatory Actions. *http://www.epa.gov/environmentaljustice/resources/policy/considering-ej-in-rulemaking-guide-final.pdf.* May 2015.

engaged meaningfully with communities throughout the development of the Clean Power Plan and has devised a robust outreach strategy for continual engagement throughout this rulemaking.

List of Subjects

40 CFR Part 60

Environmental protection, Administrative practice and procedure, Air pollution control, Intergovernmental relations.

40 CFR Part 62

Environmental protection, Administrative practice and procedure, Air pollution control, Incorporation by reference, Intergovernmental relations, Reporting and recordkeeping requirements.

40 CFR Part 78

Environmental protection, Administrative practice and procedure, Air pollution control.

Dated: August 3, 2015.

Gina McCarthy,

Administrator.

For the reasons stated in the preamble, title 40, chapter I, parts 60, 62, and 78 of the Code of the Federal Regulations is 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. 7401 *et seq.*

■ 2. Section 60.27 is amended by:

■ a. Revising paragraphs (b), (c) introductory text, and (c)(1);

■ b. Removing and reserving paragraph (c)(2);

■ c. Revising paragraphs (c)(3), (d), and (e)(1); and

■ d. Adding paragraphs (g) through (k).

The revisions and additions read as follows:

§ 60.27 Actions by the Administrator.

* * * * *

(b) After receipt of a complete plan or complete plan revision, the Administrator will propose the plan or revision for approval or disapproval. The Administrator shall, within 12 months after the date on which the submission of a complete plan or complete plan revision is received, approve or disapprove such plan or revision, or each portion thereof.

(c) The Administrator shall promulgate a federal plan within 12 months after the date the Administrator:

(1) Finds the State failed to submit a complete plan or complete plan revision within the time prescribed; or

* * * * *

(3) Disapproves the State plan or plan revision or any portion thereof, as unsatisfactory because the requirements of this subpart and the applicable emission guidelines have not been met.

(d) The Administrator will promulgate the regulations under paragraph (c) of this section for all or a portion of a federal plan, with such modifications as may be appropriate, unless, prior to such promulgation, the State has adopted and submitted a plan or plan revision which the Administrator approves. After the promulgation of a federal plan, the Administrator may approve a State plan or plan revision or portion thereof and withdraw all or a portion of the federal plan.

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

* * * * *

(g) *Completeness criteria*—(1) *General.* Within 60 days of the Administrator's receipt of a state submission, but no later than 6 months after the date, if any, by which a State is required to submit the plan or revision, the Administrator shall determine whether the minimum criteria for completeness have been met. Any plan or plan revision that a State submits to the EPA, and that has not been determined by the EPA by the date 6 months after receipt of the submission to have failed to meet the minimum criteria, shall on that date be deemed by operation of law to meet such minimum criteria. Where the Administrator determines that a plan submission does not meet the minimum criteria of this paragraph (g), the State will be treated as not having made the submission.

(2) *Administrative criteria.* In order to be complete, a State plan must contain each of the following administrative criteria:

(i) A formal letter of submittal from the Governor or her designee requesting EPA approval of the plan or revision thereof;

(ii) Evidence that the State has adopted the plan in the state code or body of regulations. That evidence must include the date of adoption or final issuance as well as the effective date of the plan, if different from the adoption/issuance date;

(iii) Evidence that the State has the necessary legal authority under state law to adopt and implement the plan;

(iv) A copy of the actual regulation, or document submitted for approval and incorporation by reference into the plan. The submittal must be a copy of the official state regulation or document signed, stamped and dated by the appropriate state official indicating that it is fully enforceable by the State. The effective date of the regulation or document must, whenever possible, be indicated in the document itself. The State's electronic copy must be an exact duplicate of the hard copy. For revisions to the approved plan, the submittal must indicate the changes made (for example, by redline/strikethrough) to the approved plan;

(v) Evidence that the State followed all of the procedural requirements of the state's laws and constitution in conducting and completing the adoption and issuance of the plan;

(vi) Evidence that public notice was given of the proposed change with procedures consistent with the requirements of § 60.23, including the date of publication of such notice;

(vii) Certification that public hearing(s) were held in accordance with the information provided in the public notice and the State's laws and constitution, if applicable and consistent with the public hearing requirements in § 60.23;

(viii) Compilation of public comments and the State's response thereto; and

(ix) Such other criteria for completeness as may be specified by the Administrator under the applicable emission guidelines.

(3) *Technical criteria.* In order to be complete, a State plan must contain each of the following technical criteria:

(i) Description of the plan approach and geographic scope;

(ii) Identification of each affected source, identification of emission standards for the affected sources, and monitoring, recordkeeping and reporting requirements that will determine compliance by each affected source;

(iii) Identification of compliance schedules and/or increments of progress;

(iv) Demonstration that the State plan submittal is projected to achieve emissions performance under the applicable emission guidelines;

(v) Documentation of state recordkeeping and reporting requirements to determine the performance of the plan as a whole; and

(vi) Demonstration that each emission standard is quantifiable, non-duplicative, permanent, verifiable, and enforceable.

(4) *Parallel processing.* A State may submit a State plan prior to actual adoption by the State in order to expedite review and provide an opportunity for the State to consider EPA comments prior to submission of a final plan for final review and action. Under these circumstances, the following exceptions to the criteria in this paragraph apply to plans submitted explicitly for parallel processing:

(i) The letter required by paragraph (g)(2)(i) of this section must request that EPA propose approval of the proposed plan by parallel processing;

(ii) In lieu of paragraph (g)(2)(ii) of this section the State must submit a schedule for final adoption or issuance of the plan;

(iii) In lieu of paragraph (g)(2)(iv) of this section the plan must include a copy of the proposed/draft regulation or document, including indication of the proposed changes to be made to the existing approved plan, where applicable; and

(iv) The requirements of paragraphs (g)(2)(v) through (ix) of this section do not apply to plans submitted for parallel processing. The exceptions granted in the preceding sentence apply only to EPA's determination of proposed action and all requirements of paragraph (g)(2) of this section must be met prior to publication of EPA's final determination of plan approvability.

(h) *Full and partial approval and disapproval.* If a portion of the plan revision meets all the applicable requirements of this chapter, the Administrator may approve the plan revision in part and disapprove the plan revision in part. The Administrator may authorize partial plan submissions in conjunction with a federal plan, where in combination, the federal and State plans constitute a complete and approvable plan meeting all of the requirements of this subpart and the applicable emissions guidelines.

(i) *Conditional approval.* The Administrator may approve a plan or a plan revision based on a commitment of the State, by a date certain established by the Administrator, to adopt specific enforceable measures, review and revise if appropriate State plans, or otherwise commit to making changes in the State's plan necessary to meet the requirements of the applicable emission guidelines. Any such conditional approval automatically converts to a disapproval if the State fails to comply with such commitment by the date certain established by the Administrator.

(j) *Calls for plan revisions.* Whenever the Administrator finds that the applicable plan is substantially inadequate to meet the requirements of the applicable emission guidelines, to provide for the implementation of such plan, or to otherwise comply with any requirement of the Clean Air Act, the Administrator must require the State to revise the plan as necessary to correct such inadequacies. The Administrator must notify the State of the inadequacies, and may establish reasonable deadlines (not to exceed 18 months after the date of such notice) for the submission of such plan revisions. Such findings and notice must be public. Any finding under this paragraph shall, to the extent the Administrator deems appropriate, subject the State to the requirements of this part to which the State was subject when it developed and submitted the plan for which such finding was made, except that the Administrator may adjust any dates applicable under such requirements as appropriate.

(k) *Error corrections.* Whenever the Administrator determines that the Administrator's action approving, disapproving, or promulgating any plan or plan revision (or portion thereof) was in error, the Administrator may in the same manner as the approval, disapproval, or promulgation revise such action as appropriate without requiring any further submission from the State. Such determination and the basis thereof shall be provided to the State and public.

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

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

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

■ 4. Add subpart MMM to read as follows:

Subpart MMM—Greenhouse Gas Emissions Mass-based Model Trading Rule for Electric Utility Generating Units That Commenced Construction on or Before January 8, 2014

Introduction

Applicability of This Subpart

General Requirements

Emission Goals, Set-Asides, and Allowance Allocations

Evaluation Measurement and Verification Plans, Monitoring and Verification Reports, and Verification

Designated Representatives

Monitoring, Recordkeeping, Reporting

Subpart MMM—Greenhouse Gas Emissions Mass-based Model Trading Rule for Electric Utility Generating Units That Commenced Construction on or Before January 8, 2014

Introduction

§ 62.16205 What is the purpose of this subpart?

(a) This subpart sets forth the requirements for the Clean Power Plan (CPP) CO_2 Mass-based Trading Program, under section 111 of the Clean Air Act and subpart UUUU of part 60 of this chapter, as a means of meeting emission guidelines limiting greenhouse gas emissions from an affected steam generating unit, integrated gasification combined cycle (IGCC), or stationary combustion turbine.

(b) The pollutants regulated by this subpart are greenhouse gases. The greenhouse gas limitations in this subpart are in the form of an emission standard for carbon dioxide (CO_2).

(c) *PSD and title V thresholds for greenhouse gases.* (1) For the purposes of § 51.166(b)(49)(ii) of this chapter, with respect to GHG emissions from affected facilities, the ''pollutant that is subject to the standard promulgated under section 111 of the Act'' is considered to be the pollutant that otherwise is subject to regulation under the Act as defined in § 51.166(b)(48) and in any state implementation plan approved by the EPA that is interpreted to incorporate, or specifically incorporates, § 51.166(b)(48) of this chapter.

(2) For the purposes of § 52.21(b)(50)(ii) of this chapter, with respect to GHG emissions from affected facilities, the ''pollutant that is subject to the standard promulgated under section 111 of the Act'' is considered to be the pollutant that otherwise is subject to regulation under the Act as defined in § 52.21(b)(49) of this chapter.

(3) For the purposes of § 70.2 of this chapter, with respect to greenhouse gas emissions from affected facilities, the ''pollutant that is subject to any standard promulgated under section 111 of the Act'' is considered to be the pollutant that otherwise is ''subject to regulation'' as defined in § 70.2 of this chapter.

(4) For the purposes of § 71.2 of this chapter, with respect to greenhouse gas emissions from affected facilities, the ''pollutant that is subject to any standard promulgated under section 111 of the Act'' is considered to be the pollutant that otherwise is ''subject to regulation'' as defined in § 71.2 of this chapter.

Applicability of this Subpart

§ 62.16210 Am I subject to this subpart?

(a) You are subject to this subpart if you are the owner or operator of an affected electric generating unit (EGU) located within a State that has incorporated by reference this subpart as a State plan, or portion of a State plan, that has been approved by the Administrator and is effective under subpart UUUU of part 60 of this chapter, or if this subpart is promulgated and effective as a federal plan in your State under part 62 of this chapter.

(b) An affected EGU is any steam generating unit, IGCC, or stationary combustion turbine that meets the applicability requirements in §§ 60.5840(b) and 60.5845 of this chapter.

§ 62.16215 What requirements apply to affected EGUs that retire?

(a) *Exemption.* (1) Any affected EGU that is permanently retired as defined in § 62.16375 is exempt from §§ 62.16220(c)(1) [CO_2 Emissions Requirements], 62.16340 [Compliance Requirements], 62.16345 [Monitoring], 62.16360 [Reporting], and 62.16365 [Recordkeeping].

(2) The exemption under paragraph (a)(1) of this section will become effective on the first day of the compliance period immediately following the compliance period in which the retirement took effect. Within 30 days of the affected EGU's permanent retirement, the designated representative must submit a statement to the Administrator. The statement must state, in a format prescribed by the Administrator, that the affected EGU was permanently retired on a specified date and will comply with the requirements of paragraph (b) of this section.

(b) *Special provisions.* (1) An affected EGU exempt under paragraph (a) of this section must not emit any CO_2, starting on the date that the exemption takes effect.

(2) For a period of 5 years from the date the records are created, the owners and operators of an affected EGU exempt under paragraph (a) of this section must retain, at the facility that includes the unit, records demonstrating that the affected EGU is permanently retired. The 5-year period for keeping records may be extended for cause, at any time before the end of the period, in writing by the Administrator. The owners and operators bear the burden of proof that the affected EGU is permanently retired.

(3) The owners and operators and, to the extent applicable, the designated representative of an affected EGU exempt under paragraph (a) of this section must comply with the requirements of the CO_2 Mass-based Trading Program accruing during any compliance periods for which the exemption is not in effect, even if such requirements must be complied with after the exemption takes effect.

General Requirements

§ 62.16220 What requirements must I comply with?

(a) *Designated representative requirements.* The owners and operators must have a designated representative, and may have an alternate designated representative, in accordance with §§ 62.16290 through 62.16300.

(b) *Emissions monitoring, reporting, and recordkeeping requirements.* (1) The owners and operators, and the designated representative, of each facility and each affected EGU at the facility must comply with the monitoring, reporting, and recordkeeping requirements of §§ 62.16345, 62.16360, and 62.16365.

(2) The emissions data determined in accordance with §§ 62.16345, 62.16360, and 62.16365 must be used to calculate allocations of CO_2 allowances under § 62.16240(a) and (b) and to determine compliance with the CO_2 emission standard under paragraph (c) of this section, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance must be the mass emissions amount for the monitoring location determined in accordance with

§ 62.16345 and rounded to the nearest ton.

(c) *CO_2 emission standard requirements*—(1) CO_2 *emission standard.* (i) As of the allowance transfer deadline for a compliance period in a given year, the owners and operators of each facility and each affected EGU at the facility with affected EGUs must hold, in the facility's compliance account, CO_2 allowances available for deduction for such compliance period under § 62.16340(a) in an amount not less than the tons of total CO_2 emissions for such compliance period from all affected EGUs at the facility.

(ii) If total CO_2 emissions during a compliance period in a given year from the affected EGUs at a facility are in excess of the CO_2 emission standard set forth in paragraph (c)(1)(i) of this section, then:

(A) The owners and operators of the facility and each affected EGU at the facility must hold the CO_2 allowances required for deduction under § 62.16340(d); and

(B) The owners and operators of the facility and each affected EGU at the facility are subject to federal enforcement pursuant to sections 113(a) through (h), and section 304, of the Clean Air Act, and the United States, States, and other persons have the ability to enforce against violations (including if an affected EGU does not meet its emission standard based on its allowances) and secure appropriate corrective actions, and must pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such compliance period will constitute a separate violation of this subpart and the Clean Air Act.

(2) *Compliance periods.* (i) An affected EGU will be subject to the requirements under paragraph (c)(1) of this section for the compliance period starting on January 1, 2022 and for each compliance period thereafter.

(ii) [Reserved]

(3) *Vintage of allowances held for compliance.* (i) A CO_2 allowance held for compliance with the requirements under paragraph (c)(1)(i) of this section for a compliance period must be a CO_2 allowance that was allocated for a year in such compliance period or for a year in a prior compliance period.

(ii) A CO_2 allowance held for compliance with the requirements under paragraph (c)(1)(ii)(A) of this section for a compliance period must be a CO_2 allowance that was allocated for a year in a prior compliance period, or the current compliance period, or in the immediately following compliance period.

(4) *Allowance Tracking and Compliance System (ATCS) requirements.* Each CO_2 allowance must be held in, deducted from, or transferred into, out of, or between ATCS accounts in accordance with this subpart.

(5) *Limited authorization.* A CO_2 allowance is a limited authorization to emit one ton of CO_2 during the compliance period in one year. Such authorization is limited in its use and duration as follows:

(i) Such authorization must only be used in accordance with the CO_2 Mass-based Trading Program; and

(ii) Notwithstanding any other provision of this subpart, the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.

(6) *Property right.* A CO_2 allowance does not constitute a property right.

(d) *Title V permit requirements.* (1) Unless otherwise specified in this paragraph, all requirements of this subpart are applicable requirements that must be included in an affected EGU's title V permit.

(2) The applicable requirements of this subpart, as well as other terms or conditions necessary to ensure compliance with the applicable requirements, may be added to, or changed in, a title V permit using minor permit modification procedures in accordance with §§ 70.7(e)(2) and 71.7(e)(1) of this chapter, provided that such changes do not conflict with any existing terms of the permit. This paragraph explicitly provides that the addition of, or change to, an affected EGU's description as described in the prior sentence is eligible for minor permit modification procedures in accordance with §§ 70.7(e)(2)(i)(B) and 71.7(e)(1)(i)(B) of this chapter.

(3) No title V permit revision will be required for any allocation, holding, deduction, or transfer of CO_2 allowances in accordance with this subpart, provided that the requirements applicable to such allocations, holdings, deductions, or transfers of CO_2 allowances are already incorporated in such permit.

(e) *Liability.* (1) Any provision of the CO_2 Mass-based Trading Program that applies to an affected EGU at a facility or the designated representative of affected EGUs at a facility will also apply to the owners and operators of such facility and of the affected EGUs at the facility.

(2) Any provision of the CO_2 Mass-based Trading Program that applies to an affected EGU or the designated representative of an affected EGU will also apply to the owners and operators of such affected EGU.

(f) *Effect on other authorities.* No provision of the CO_2 Mass-based Trading Program or exemption under § 62.16215 shall be construed as exempting or excluding the owners and operators, and the designated representative, of an affected EGU from compliance with any other provision of the applicable, approved state implementation plan, a federally enforceable permit, or any other requirement of the Clean Air Act.

§ 62.16225 How should I compute time under the CO_2 Mass-based Trading Program?

(a) Unless otherwise stated, any time period scheduled, under the CO_2 Mass-Based Trading Program, to begin on the occurrence of an act or event will begin on the day the act or event occurs.

(b) Unless otherwise stated, any time period scheduled, under the CO_2 Mass-Based Trading Program, to begin before the occurrence of an act or event will be computed so that the period ends the day before the act or event occurs.

(c) Unless otherwise stated, if the final day of any time period, under the CO_2 Mass-Based Trading Program, is not a business day, then the time period will be extended to the next business day.

§ 62.16230 What are the administrative appeal procedures?

The administrative appeal procedures for decisions of the Administrator under the CO_2 Mass-Based Trading Program are set forth in part 78 of this chapter.

§ 62.16231 How will the Clean Energy Incentive Program be administered under the federal plan?

(a)(1) The Administrator will participate in the Clean Energy Incentive Program, established under subpart UUUU of part 60 of this chapter, on behalf of any state for which this subpart is promulgated as a federal plan under section 111(d) of the Clean Air Act. The Administrator will award, on behalf of each such state, early action allowances for generation and savings achieved in 2020 and/or 2021 that result from the following types of eligible renewable energy (RE) and demand-side energy efficiency (EE) projects:

(i) Metered wind power;

(ii) Metered solar power; and

(iii) Demand-side EE implemented in a low-income community.

(2) Eligible RE projects must commence construction, and eligible demand-side EE projects must

commence implementation after September 6, 2018 for those states on whose behalf the EPA is implementing the federal plan. Eligible projects must be located in or benefit the state on whose behalf the EPA is implementing the federal plan.

(b) Early action allowances will be distributed pursuant to a process to be prescribed by the Administrator, from an allowance set-aside equal to 300 million allowances for all states. This set-aside does not increase the total budget of allowances for the affected EGUs in the state subject to this subpart.

(c) The Administrator will match these early action allowances with additional matching allowances pursuant to a process to be prescribed by the Administrator. Matching awards will be made up to a limit equivalent to the state's pro rata share of 300 million short tons of CO_2 emissions.

(d) The awards, including the matching award, will be executed as follows:

(1) For RE projects that generate metered MWh from wind or solar resources: for every two MWh generated, the project will receive a number of early action allowances the Administrator determines to be equivalent to one MWh from the set-aside under paragraph (b) of this section and a number of matching allowances the Administrator determines to be equivalent to one MWh from the match under paragraph (c) of this section.

(2) For EE projects implemented in low-income communities as determined by the Administrator solely for purposes of this subpart: for every two MWh in end-use demand savings achieved, the project will receive a number of early action allowances the Administrator determines to be equivalent to two MWh from the set-aside under paragraph (b) of this section and a number of matching allowances the Administrator determines to be equivalent to two MWh from the match under paragraph (c) of this section.

Emission Goals, Set-Asides, and Allowance Allocations

§ 62.16235 What are the statewide mass-based emission goals, renewable energy set-asides, output-based set-asides, and Clean Energy Incentive Program early action set-asides?

(a) The statewide mass-based emission goals with renewable energy set-asides and output-based set-asides for allocations of CO_2 allowances for the interim 3- and 2-year compliance periods in 2022 through 2029, and the final 2-year compliance periods in 2030 and thereafter are specified in Table 1 of this subpart.

TABLE 1 TO SUBPART MMM OF PART 62—STATEWIDE MASS-BASED EMISSION GOALS [1] (SHORT TONS)

State	Interim period			Final period
	Step 1 2022–2024	Step 2 2025–2027	Step 3 2028–2029	2030–2031 and thereafter
Alabama	66,164,470	60,918,973	58,215,989	56,880,474
Arizona	35,189,232	32,371,942	30,906,226	30,170,750
Arkansas	36,032,671	32,953,521	31,253,744	30,322,632
California	53,500,107	50,080,840	48,736,877	48,410,120
Colorado	35,785,322	32,654,483	30,891,824	29,900,397
Connecticut	7,555,787	7,108,466	6,955,080	6,941,523
Delaware	5,348,363	4,963,102	4,784,280	4,711,825
Florida	119,380,477	110,754,683	106,736,177	105,094,704
Georgia	54,257,931	49,855,082	47,534,817	46,346,846
Idaho	1,615,518	1,522,826	1,493,052	1,492,856
Illinois	80,396,108	73,124,936	68,921,937	66,477,157
Indiana	92,010,787	83,700,336	78,901,574	76,113,835
Iowa	30,408,352	27,615,429	25,981,975	25,018,136
Kansas	26,763,719	24,295,773	22,848,095	21,990,826
Kentucky	76,757,356	69,698,851	65,566,898	63,126,121
Lands of the Fort Mojave Tribe	636,876	600,334	588,596	588,519
Lands of the Navajo Nation	26,449,393	23,999,556	22,557,749	21,700,587
Lands of the Uintah and Ouray Reservation	2,758,744	2,503,220	2,352,835	2,263,431
Louisiana	42,035,202	38,461,163	36,496,707	35,427,023
Maine	2,251,173	2,119,865	2,076,179	2,073,942
Maryland	17,447,354	15,842,485	14,902,826	14,347,628
Massachusetts	13,360,735	12,511,985	12,181,628	12,104,747
Michigan	56,854,256	51,893,556	49,106,884	47,544,064
Minnesota	27,303,150	24,868,570	23,476,788	22,678,368
Mississippi	28,940,675	26,790,683	25,756,215	25,304,337
Missouri	67,312,915	61,158,279	57,570,942	55,462,884
Montana	13,776,601	12,500,563	11,749,574	11,303,107
Nebraska	22,246,365	20,192,820	18,987,285	18,272,739
Nevada	15,076,534	14,072,636	13,652,612	13,523,584
New Hampshire	4,461,569	4,162,981	4,037,142	3,997,579
New Jersey	18,241,502	17,107,548	16,681,949	16,599,745
New Mexico	14,789,981	13,514,670	12,805,266	12,412,602
New York	35,493,488	32,932,763	31,741,940	31,257,429
North Carolina	60,975,831	55,749,239	52,856,495	51,266,234
North Dakota	25,453,173	23,095,610	21,708,108	20,883,232
Ohio	88,512,313	80,704,944	76,280,168	73,769,806
Oklahoma	47,577,611	43,665,021	41,577,379	40,488,199
Oregon	9,097,720	8,477,658	8,209,589	8,118,654
Pennsylvania	106,082,757	97,204,723	92,392,088	89,822,308
Rhode Island	3,811,632	3,592,937	3,522,686	3,522,225
South Carolina	31,025,518	28,336,836	26,834,962	25,998,968
South Dakota	4,231,184	3,862,401	3,655,422	3,539,481

TABLE 1 TO SUBPART MMM OF PART 62—STATEWIDE MASS-BASED EMISSION GOALS [1] (SHORT TONS)—Continued

State	Interim period			Final period
	Step 1 2022–2024	Step 2 2025–2027	Step 3 2028–2029	2030–2031 and thereafter
Tennessee	34,118,301	31,079,178	29,343,221	28,348,396
Texas	221,613,296	203,728,060	194,351,330	189,588,842
Utah	28,479,805	25,981,970	24,572,858	23,778,193
Virginia	31,290,209	28,990,999	27,898,475	27,433,111
Washington	12,395,697	11,441,137	10,963,576	10,739,172
West Virginia	62,557,024	56,762,771	53,352,666	51,325,342
Wisconsin	33,505,657	30,571,326	28,917,949	27,986,988
Wyoming	38,528,498	34,967,826	32,875,725	31,634,412

[1] The values in this table are annual amounts; the mass goal for each multi-year compliance period is the annual value multiplied by the number of years in the compliance period. Each emission goal includes the renewable energy set-asides and output-based set-asides (the output-based set-asides are zero in the first compliance period). The first compliance period goals also include the early action Clean Energy Incentive Program set-aside.

(b) If implementing interstate trading, then the Administrator will use the sum of a covered group of States' mass-based emission goals as the aggregate mass-based emission goal.

(c) The renewable energy set-aside for each State covered by the federal mass-based emissions trading plan must reserve 5 percent from the State's annual allowances prior to allocation of that year's allowances to facilities. The renewable energy set-asides are specified in Table 2 of this subpart.

TABLE 2 TO SUBPART MMM OF PART 62—STATEWIDE RENEWABLE ENERGY SET-ASIDE (SHORT TONS)

State	Interim period			Final period
	Compliance period 1 2022–2024	Compliance period 2 2025–2027	Compliance period 3 2028–2029	Final compliance periods 2030–2031 and thereafter
Alabama	3,308,224	3,045,949	2,910,799	2,844,024
Arizona	1,759,462	1,618,597	1,545,311	1,508,538
Arkansas	1,801,634	1,647,676	1,562,687	1,516,132
California	2,675,005	2,504,042	2,436,844	2,420,506
Colorado	1,789,266	1,632,724	1,544,591	1,495,020
Connecticut	377,789	355,423	347,754	347,076
Delaware	267,418	248,155	239,214	235,591
Florida	5,969,024	5,537,734	5,336,809	5,254,735
Georgia	2,712,897	2,492,754	2,376,741	2,317,342
Idaho	80,776	76,141	74,653	74,643
Illinois	4,019,805	3,656,247	3,446,097	3,323,858
Indiana	4,600,539	4,185,017	3,945,079	3,805,692
Iowa	1,520,418	1,380,771	1,299,099	1,250,907
Kansas	1,338,186	1,214,789	1,142,405	1,099,541
Kentucky	3,837,868	3,484,943	3,278,345	3,156,306
Lands of the Fort Mojave Tribe	31,844	30,017	29,430	29,426
Lands of the Navajo Nation	1,322,470	1,199,978	1,127,887	1,085,029
Lands of the Uintah and Ouray Reservation	137,937	125,161	117,642	113,172
Louisiana	2,101,760	1,923,058	1,824,835	1,771,351
Maine	112,559	105,993	103,809	103,697
Maryland	872,368	792,124	745,141	717,381
Massachusetts	668,037	625,599	609,081	605,237
Michigan	2,842,713	2,594,678	2,455,344	2,377,203
Minnesota	1,365,158	1,243,429	1,173,839	1,133,918
Mississippi	1,447,034	1,339,534	1,287,811	1,265,217
Missouri	3,365,646	3,057,914	2,878,547	2,773,144
Montana	688,830	625,028	587,479	565,155
Nebraska	1,112,318	1,009,641	949,364	913,637
Nevada	753,827	703,632	682,631	676,179
New Hampshire	223,078	208,149	201,857	199,879
New Jersey	912,075	855,377	834,097	829,987
New Mexico	739,499	675,734	640,263	620,630
New York	1,774,674	1,646,638	1,587,097	1,562,871
North Carolina	3,048,792	2,787,462	2,642,825	2,563,312
North Dakota	1,272,659	1,154,781	1,085,405	1,044,162
Ohio	4,425,616	4,035,247	3,814,008	3,688,490
Oklahoma	2,378,881	2,183,251	2,078,869	2,024,410
Oregon	454,886	423,883	410,479	405,933
Pennsylvania	5,304,138	4,860,236	4,619,604	4,491,115
Rhode Island	190,582	179,647	176,134	176,111

TABLE 2 TO SUBPART MMM OF PART 62—STATEWIDE RENEWABLE ENERGY SET-ASIDE (SHORT TONS)—Continued

State	Interim period			Final period
	Compliance period 1 2022–2024	Compliance period 2 2025–2027	Compliance period 3 2028–2029	Final compliance periods 2030–2031 and thereafter
South Carolina	1,551,276	1,416,842	1,341,748	1,299,948
South Dakota	211,559	193,120	182,771	176,974
Tennessee	1,705,915	1,553,959	1,467,161	1,417,420
Texas	11,080,665	10,186,403	9,717,567	9,479,442
Utah	1,423,990	1,299,099	1,228,643	1,188,910
Virginia	1,564,510	1,449,550	1,394,924	1,371,656
Washington	619,785	572,057	548,179	536,959
West Virginia	3,127,851	2,838,139	2,667,633	2,566,267
Wisconsin	1,675,283	1,528,566	1,445,897	1,399,349
Wyoming	1,926,425	1,748,391	1,643,786	1,581,721

(d) The output-based set-aside for each State under this subpart, beginning in compliance period 2, must reserve a share of the State's annual allowances prior to allocation of that year's allowances to facilities as set forth in this paragraph (d). The output-based set-asides are specified in Table 3 of this subpart.

TABLE 3 TO SUBPART MMM OF PART 62—STATEWIDE OUTPUT-BASED SET-ASIDE (SHORT TONS)

State	Allowances in output-based set-aside (short tons)
Alabama	4,185,496
Arizona	4,197,813
Arkansas	2,102,538
California	8,458,604
Colorado	1,348,187
Connecticut	1,090,811
Delaware	649,190
Florida	12,102,688
Georgia	3,563,104
Idaho	246,638
Illinois	1,598,615
Indiana	1,106,150
Iowa	492,510
Kansas	62,257
Kentucky	288,730
Lands of the Fort Mojave Tribe	248,127
Lands of the Navajo Nation	0
Lands of the Uintah and Ouray Reservation	0
Louisiana	2,207,879
Maine	563,925
Maryland	103,762
Massachusetts	2,439,991
Michigan	2,105,786
Minnesota	909,724
Mississippi	3,132,671
Missouri	815,210
Montana	0
Nebraska	144,635
Nevada	2,326,529
New Hampshire	542,721
New Jersey	3,413,100
New Mexico	627,085
New York	3,815,381
North Carolina	2,120,178
North Dakota	0
Ohio	1,757,326
Oklahoma	3,121,167
Oregon	1,291,027
Pennsylvania	4,392,931
Rhode Island	778,307
South Carolina	1,029,366
South Dakota	130,831
Tennessee	632,949
Texas	15,990,657
Utah	825,586
Virginia	3,011,811

TABLE 3 TO SUBPART MMM OF PART 62—STATEWIDE OUTPUT-BASED SET-ASIDE (SHORT TONS)—Continued

State	Allowances in output-based set-aside (short tons)
Washington	1,383,060
West Virginia	0
Wisconsin	1,181,175
Wyoming	45,114

(e)(1) The Clean Energy Investment Program Set-Aside for each State covered under this subpart must contain an amount of allowances shown in Table 4 of this subpart, which must reserve a share of the State's annual allowances prior to allocation of that year's allowances to facilities as set forth in this paragraph.

TABLE 4 TO SUBPART MMM OF PART 62—CLEAN ENERGY INVESTMENT PROGRAM EARLY ACTION SET-ASIDE (SHORT TONS)

State	Allowances in early action set-aside (short tons)
Alabama	3,122,306
Arizona	1,719,618
Arkansas	2,187,230
California	218,846
Colorado	2,223,192
Connecticut	69,415
Delaware	138,392
Florida	3,230,248
Georgia	2,755,623
Idaho	14,929
Illinois	5,968,721
Indiana	5,754,076
Iowa	2,191,183
Kansas	2,115,630
Kentucky	4,952,862
Lands of the Fort Mojave Tribe	5,885
Lands of the Navajo Nation	1,623,066
Lands of the Uintah and Ouray Reservation	175,509
Louisiana	1,497,428
Maine	20,739
Maryland	972,775
Massachusetts	170,471
Michigan	3,727,861
Minnesota	2,002,903
Mississippi	357,307
Missouri	3,771,322
Montana	1,310,344
Nebraska	1,481,695
Nevada	336,288
New Hampshire	107,798
New Jersey	446,005
New Mexico	823,049
New York	557,771
North Carolina	2,674,590
North Dakota	2,150,635
Ohio	4,788,372
Oklahoma	2,067,006
Oregon	154,353
Pennsylvania	5,039,346
Rhode Island	35,674
South Carolina	1,652,802
South Dakota	264,207
Tennessee	2,178,084
Texas	10,400,192
Utah	1,401,189
Virginia	1,386,546
Washington	751,434
West Virginia	3,506,890
Wisconsin	2,393,870
Wyoming	3,104,324

(2) Allowances may be distributed from the set-aside for projects meeting the criteria of paragraph (e)(3) of this section, upon application of a project proponent that meets the requirements of § 62.16245(a), except as may be prescribed by the Administrator in a future action. In order to receive a distribution, the project proponent must establish a general account in the tracking system as provided in § 62.16320(c).

(3) Projects eligible for distribution of allowances from this set-aside must meet each of the criteria in paragraphs (e)(3)(i) through (iii) of this section. All categories of resources other than those listed in paragraphs (e)(3)(iii)(A) and (B) of this section, and all provisions of this subpart relating to such resources, are not available or applicable in States where this subpart has been promulgated as a federal plan pursuant to section 111(d)(2) of the Clean Air Act.

(i) The project was constructed or implemented on or after the signature date of the final rule promulgating subpart UUUU of part 60 of this chapter;

(ii) The creditable generation or energy savings from the project must occur in calendar years 2020 or 2021; and

(iii) Generation or energy savings must be from one of the following types of sources capable of revenue-quality metering:

(A) Onshore wind;

(B) Solar; or

(C) Demand-side EE.

§ 62.16240 When are allowances allocated?

(a) *Allowance allocations.* (1) By June 1, 2021, and by June 1 of each year prior to the beginning of each compliance period thereafter, CO_2 allowances will be allocated, for the multi-year compliance periods in the Interim Period beginning in 2022 and the Final Period beginning in 2030, as provided by the Administrator in a notice of data availability or through this subpart (if applicable). Providing an allocation to an entity does not constitute as an applicability determination of an affected EGU.

(2) Notwithstanding paragraph (a)(1) of this section, if an affected EGU which is provided an allocation does not operate for 2 consecutive calendar years, then such affected EGU will not be allocated the CO_2 allowances provided by the Administrator in a notice of data availability or through this subpart (if applicable) for the affected EGU for the next compliance period for which allowances have not yet been recorded and for each compliance period after that compliance period. All CO_2 allowances that would otherwise have been allocated to such affected EGU will be allocated to the renewable energy set-aside for the State where such affected EGU is located and for the respective compliance periods involved.

(3) Notwithstanding paragraph (a)(1) of this section, if an affected EGU provided an allocation issued by the Administrator in notice of data availability or through this subpart (if applicable) is modified or reconstructed such that it is no longer subject to this subpart, then such affected EGU will not be allocated the CO_2 allowances provided for the affected EGU for the next compliance period for which allowances have not yet been recorded and for each compliance period after that compliance period. All CO_2 allowances that would otherwise have been allocated to such affected EGU will be allocated to the renewable energy set-aside for the State where such affected EGU is located and for the respective compliance periods involved.

(b) *Set-asides*—(1) *Renewable energy set-asides.* (i) By December 1, 2021 and December 1 of each year thereafter, the Administrator will calculate and allocate the CO_2 allowance allocation to each approved renewal energy project in a State, in accordance with § 62.16245(a)(2) through (5), for the generation year of the applicable calculation deadline under this paragraph.

(ii) By December 1, 2021 and December 1 of each year thereafter, the Administrator will calculate and allocate the CO_2 allowance allocation to each affected EGU in a State, in accordance with § 62.16245(a)(6) and (7) for the generation year of the applicable calculation, and will promulgate a notice of data availability of the results of the calculations.

(2) *Output-based set-asides.* (i) By November 1 of the first year of each compliance period beginning in 2025, and each compliance period thereafter, the Administrator will calculate and allocate the CO_2 allowance allocation to each affected EGU in a State, in accordance with § 62.16245(b)(3), for the generation period of the applicable calculation deadline under this paragraph.

(ii) By November 1 of the first year of each compliance period beginning in 2025, and each compliance period thereafter, the Administrator will calculate and allocate the CO_2 allowance allocation to each affected EGU in a State, in accordance with § 62.16245(b)(4) and (5) for the generation period of the applicable calculation, and will promulgate a notice of data availability of the results of the calculations.

(c) *Affected EGUs incorrectly allocated CO_2 allowances.* (1) For each compliance period in 2022 and thereafter, if the Administrator determines that CO_2 allowances were allocated under paragraph (a) of this section, or under a provision of a state allowance distribution methodology approved under subpart UUUU of part 60 of this chapter, where such compliance period and the recipient are covered by the provisions of paragraph (c)(1)(i) of this section or were allocated under § 62.16245(a) and (b), where such compliance period and the recipient are covered by the provisions of paragraph (c)(1)(ii) of this section, then the Administrator will notify the designated representative of the recipient and will act in accordance with the procedures set forth in paragraphs (c)(2) through (5) of this section. The situations for the Administrator to act according to the procedures in paragraphs (c)(2) through (5) are if:

(i)(A) The recipient is not actually an affected EGU under § 62.16210 as of January 1, 2022 and is allocated CO_2 allowances for such compliance period or, in the case of an allocation under a provision of a state allowance distribution methodology approved under subpart UUUU of part 60 of this chapter, the recipient is not actually an affected EGU as of January 1, 2022 and is allocated CO_2 allowances for such compliance period that the state allowance distribution methodology provides should be allocated only to recipients that are affected EGUs as of January 1, 2022; or

(B) The recipient is not located as of January 1 of the compliance period in the State from whose CO_2 allowances the CO_2 allowances allocated under paragraph (a) of this section, or under a provision of a state allowance distribution methodology approved under subpart UUUU of part 60 of this chapter, were allocated for such compliance period.

(ii) The recipient is not actually an affected EGU under § 62.16210 as of January 1 of such compliance period and is allocated CO_2 allowances for such compliance period or, in the case of an allocation under a provision of a state allowance distribution methodology approved under subpart UUUU of part 60 of this chapter, the recipient is not actually an affected EGU as of January 1 of such compliance period and is allocated CO_2 allowances for such compliance period that the state allowance distribution methodology provides should be allocated only to recipients that are affected EGUs as of January 1 of such compliance period.

(2) Except as provided in paragraph (c)(3) or (4) of this section, the Administrator will not record such CO_2 allowances under § 62.16325.

(3) If the Administrator already recorded such CO_2 allowances under § 62.16325 and if the Administrator makes the determination under paragraph (c)(1) of this section before making deductions for the facility that includes such recipient under § 62.16340(b) for such compliance period, then the Administrator will deduct from the account in which such CO_2 allowances were recorded an amount of CO_2 allowances allocated for the same or a prior compliance period equal to the amount of such already-recorded CO_2 allowances. The authorized account representative must ensure that there are sufficient CO_2 allowances in such account for completion of the deduction.

(4) If the Administrator already recorded such CO_2 allowances under § 62.16325 and if the Administrator makes the determination under paragraph (c)(1) of this section after making deductions for the facility that includes such recipient under § 62.16340(b) for such compliance period, then the Administrator will not make any deduction to take account of such already-recorded CO_2 allowances.

(5)(i) With regard to the CO_2 allowances that are not recorded, or that are deducted as an incorrect allocation, in accordance with paragraphs (c)(2) and (3) of this section for a recipient under paragraph (c)(1)(i) of this section, the Administrator will:

(A) Transfer such CO_2 allowances to the renewable energy set-aside for such compliance period for the State from whose CO_2 allowances the CO_2 allowances were allocated; or

(B) If the State has a state allowance distribution methodology approved under subpart UUUU of part 60 of this chapter covering such compliance period, then include such CO_2 allowances in the portion of the CO_2 allowances that may be allocated for such compliance period in accordance with such state allowance distribution methodology.

(ii) With regard to the CO_2 allowances that were not allocated from a renewable energy or output-based set-aside for such compliance period and that are not recorded, or that are deducted as an incorrect allocation, in accordance with paragraphs (c)(2) and (3) of this section for a recipient under paragraph (c)(1)(ii) of this section, the Administrator will:

(A) Transfer such CO_2 allowances to the renewable energy set-aside for such compliance period; or

(B) If the State has a state allowance distribution methodology approved under subpart UUUU of part 60 of this chapter covering such compliance period, then include such CO_2 allowances in the portion of the CO_2 allowances that may be allocated for such compliance period in accordance with such state allowance distribution methodology.

(iii) With regard to the CO_2 allowances that were allocated from the renewable energy or output-based set-aside for such compliance period and that are not recorded, or that are deducted as an incorrect allocation, in accordance with paragraphs (c)(2) and (3) of this section for a recipient under paragraph (c)(1)(ii) of this section, the Administrator will transfer such CO_2 allowances back to the renewable energy set-aside, or to the output-based set-aside, respectively, for such compliance period.

§ 62.16245 How are set-aside allowances allocated?

(a)(1) *Renewable energy set-aside.* The Administrator will establish a renewable energy set-aside as set forth in § 62.16235(c), and allocate CO_2 allowances from the set-aside for each year of a compliance period as outlined in this section.

(2) *Eligible renewable energy capacity.* To be eligible to receive renewable energy set-aside allowances, an eligible resource must meet each of the requirements in paragraphs (a)(2)(i) through (v) of this section. Any resource that does not meet the requirements of paragraphs (a)(2)(i) through (v) of this section cannot receive set-aside allowances.

(i) The resource must be a renewable energy resource that falls into one of the following categories of resources: on-shore utility scale wind, solar, geothermal power, or utility scale hydropower.

(ii) The resources must only include resources which increased new installed electrical generation nameplate capacity, or new electrical savings measures installed or implemented after January 1, 2013. If a resource had a nameplate capacity uprate, then set-aside allowances may be issued only for the difference in generation between the uprated nameplate capacity and its nameplate capacity prior to the uprate. Set-aside allowances must not be issued for generation for an uprate that followed a derate that occurred on or after January 1, 2013. A resource that is relicensed or receives a license extension is considered existing capacity and is not an eligible resource, unless it receives a capacity uprate as a result of the relicensing process that is reflected in its relicensed permit. In such a case, only the difference in nameplate capacity between its relicensed permit and its prior permit is eligible to be issued set-aside allowances.

(iii) The resource must be located in the mass-based State for which the set-aside has been designated.

(iv) The resource must be connected to, and delivers energy to or saves electricity, on the electric grid in the contiguous United States.

(v) The resource must not have received emission rate credits (ERCs) for any period of time for which it receives set-aside allowances.

(3) *Process for issuance of set-aside allowances.* The process and requirements for issuance of set-aside allowances are set forth in paragraphs (a)(3)(i) through (x) of this section.

(i) Eligibility application. To receive set-aside allowances, an authorized account representative of an eligible resource must submit an eligibility application to the Administrator that demonstrates that the requirements of paragraph (a)(2) of this section are met and demonstrates that the following requirements are met:

(A) Identification of the authorized account representative of the eligible resource, including the authorized account representative's name, address, email address, telephone number, and allowance tracking system account number; and

(B) Identification of the eligible resource(s), including the physical location of the eligible resource; contact information for the owner or operator of the eligible resource, if different from the authorized account representative and designated representative; generator prime mover and technology type; generator nameplate capacity (if applicable); generator category (*e.g.,* wholesale generator, wholesale generator also serving onsite customer load, customer-sited distributed generator) (if applicable); facility and generating unit IDs (EIA ORIS Code, Facility Registration System (FRS) Code, if applicable) (if applicable); the control area, balancing authority, ISO conditions as defined in § 62.16375 (if applicable), or regional transmission organization in which the generator is located (if applicable); and a copy of the most recent filing of a copy of the generating facility's U.S. Energy Information Agency's Annual Electric Generator Report Form EIA–860 (if applicable).

(ii) Renewable energy providers must open a general account per the requirements in § 62.16320(c), and submit a project application for renewable energy set-aside allowances to the Administrator by June 1 of the year prior to the generation year for which set-aside allowances are requested. Providers may update submitted projections for future generation years, these projections must be received by June 1 of the year prior to the generation year in question. The project application must contain the following information:

(A) Projection of the project's annual renewable energy generation in MWh.

(B) Documentation of the methodology, data facilities, and assumptions used to project the project's annual renewable energy generation.

(C) A certification that the eligibility application has only been submitted to the Administrator or pursuant to an EPA-approved multi-State approach where States are providing for joint issuance of allowances pursuant to the authority in their individual State plans.

(D) A evaluation, measurement, and verification (EM&V) plan.

(E) A verification report from an accredited independent verifier who meets the requirements of § 62.16275 and § 62.16280. While considered a part of the eligibility application, the verification report must be submitted separately by the accredited independent verifier to the Administrator.

(F) An authorization that provides for the following: the Administrator may inspect (including a physical inspection of the eligible resource and its meter) and/or audit the eligible resource at any time and verify that the eligible resource and the EM&V plan have been implemented as described in the eligibility application.

(G) The following statement, signed by the authorized account representative of the eligible resource:

(1) ''I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my personal knowledge and/or inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.''

(2) [Reserved]

(H) Any other information required by the Administrator.

(4) *Monitoring and verification.* After the generation year for which a provider received set-aside allowances for an eligible resource, the authorized account representative must submit to the Administrator:

(i) A measurement and verification (M&V) report.

(ii) A verification report from an accredited independent verifier that meets the requirements of § 62.16275 and § 62.16280. While considered a part of the M&V report, the verification report must be submitted separately by the accredited independent verifier to the Administrator.

(5) *Allocation of renewable energy set-aside allowances.* The Administrator will enter the projected generation from each approved project into a pool of projects for that State that will receive set-asides for a generation year.

(i) The Administrator will distribute renewable energy set-aside allowances for a generation year with the number of allowances distributed to each project prorated according to its percentage of the total approved projected MWhs for that State that the project represents.

(ii) If in the previous generation year, the project did not reach the MWhs projected, then the unfulfilled MWhs will be subtracted from that provider's projected generation eligible for the set-aside pool.

(iii) If the unfulfilled MWhs from a previous year exceed the projected hours for the generation year, then the Administrator will carry over the deficit and subtract from the projected generation in subsequent years until there is no deficit. If this deficit is greater than 10 percent in a particular year, then the provider will need to provide an explanation to the Administrator of the deficit, and will be required to reevaluate their projections for future years. If such deficits continue through all 3 years of the first or second compliance period, then the Administrator will disqualify the provider from receiving future set-asides for the following compliance period.

(6) *Surplus renewable set-aside allowances.* If, after completion of the procedures under paragraph (a)(5) of this section for each compliance period, any unallocated CO_2 allowances remain in the renewable energy set-aside for the State for such generation year, the Administrator will allocate the amount of CO_2 allowances in a pro rata fashion on the same distribution basis as their initial allocations were made to each affected EGU that: is in the State; is allocated an amount of CO_2 allowances in the notice of data availability issued under § 62.16240(a)(1); and continues to be allocated CO_2 allowances for such compliance period in accordance with § 62.16240(a)(2).

(7) *Notice of surplus renewable energy set-aside allowance distribution.* The Administrator will make public the amount of CO_2 allowances allocated under paragraph (a)(6) of this section for such generation year period to each affected EGU eligible for such allocation.

(b)(1) *Output-based set-aside.* The Administrator will establish an output-based set-aside beginning in compliance period 2, and allocate CO_2 allowances from the set-aside for each year of a compliance period as set forth in § 62.16235(c).

(2) *Unit eligibility.* To be eligible to receive output-based set-aside allowances, affected EGUs must meet the following eligibility requirements:

(i) The affected EGU must be a natural gas combined cycle unit;

(ii) The affected EGU must be located in the mass-based State for which the set-aside has been designated; and

(iii) The affected EGU's average capacity factor in the preceding compliance period was above 50 percent based on net summer capacity and net generation.

(3) *Allocation of output-based set-aside allowances.* The Administrator will allocate output based set-aside allowances for each eligible EGU based on its average net generation and net summer capacity in the preceding compliance period.

(i) The Administrator will calculate the amount of allowances an eligible EGU receives from the output-based set-aside as the unit's average net generation in the preceding compliance period over 50 percent multiplied by the allocation rate of 1,030 lb/MWh-net.

(ii) If the amount of total allowances exceeds the size of the State's set-aside, then the allowances will be allocated to the State's eligible generation on a pro-rata basis.

(iii) The Administrator will provide notice of the net summer capacity and net generation data used, and the resulting allocations by August 1 of the first year of each compliance period beginning in 2025. The notice of the net summer capacity and net generation data used, and the resulting allocations, must allow 30 days for public comment on the data and allocations, until August 31 of the same year.

(iv) The Administrator will provide notice of the final set-aside allocations by November 1 of the same year.

(4) *Surplus output-based set-aside allowances.* If, after completion of the

procedures under paragraph (b)(3) of this section for each compliance period, any unallocated CO_2 allowances remain in the out-put based set-aside for the State for such generation period, the Administrator will allocate the amount of CO_2 allowances in a pro rata fashion on the same distribution basis as their initial allocations were made to each affected EGU that: is in the State; is allocated an amount of CO_2 allowances in the notice of data availability issued under § 62.16240(a)(1); and continues to be allocated CO_2 allowances for such compliance period in accordance with § 62.16240(a)(2).

(5) *Notice of surplus output-based set-aside.* The Administrator will notify the public, through the promulgation of the notices of data availability described in § 62.16240(b)(1) and (2), of the amount of CO_2 allowances allocated under paragraphs (b)(3) and (4) of this section for such compliance period to each affected EGU eligible for such allocation.

§ 62.16250 What is the process for revocation of qualification status of an eligible resource?

(a) If an eligible resource is found to not meet the requirements of § 62.16260 in the CO_2 Mass-based Trading Program, then the Administrator will revoke the eligibility of the eligible resource to be issued set-aside allowances. In addition, the provisions of § 62.16255(d) may apply.

(b) Any instance of intentional misrepresentation in an eligibility application or M&V report may be cause for revocation of the qualification status of an eligible resource.

(c) Repeated instances of error or misstatement of MWh of electricity generation or savings in submitted M&V reports, or in any other submissions may be cause for the Administrator to revoke the eligibility of an eligible resource to be issued set-aside allowances.

(d) In the event of an intentional misrepresentation, or repeated instances of error or misstatement, in program submissions, by the authorized account representative of the eligible resource, the Administrator may prohibit the eligible resource from any further eligibility to be issued allowances. In addition, the provisions of § 62.16255(a) through (d) may apply.

§ 62.16255 What is the process for error adjustments or misstatement, and suspension of allowance issuance?

(a) In the event of error or misstatement of quantified MWh of electricity generation or savings in a previous M&V report for which set-aside allowances have been issued, the Administrator may adjust the number of set-aside allowances issued in a subsequent reporting period to address the error or misstatement, by subtracting a number of MWh from the quantified and verified MWh in the M&V report for the subsequent reporting period. In the event that an error or inadvertent misstatement occurs in a final M&V report for an eligible resource, for which set-aside allowances have been issued, the provisions of paragraph (b) of this section will apply.

(b) In the event of error or misstatement of quantified MWh of electricity generation or savings in the final M&V report for an eligible resource, for which set-aside allowances have been issued, the Administrator will revoke set-aside allowances from the general account held by the authorized account representative of the eligible resource, in an amount necessary to correct the error or misstatement. In the event that the general account of the eligible resource holds an insufficient number of set-aside allowances to correct the error or misstatement, the authorized account representative must submit to the Administrator within 30 days a number of set-aside allowances necessary to correct the error or misstatement. Failure to meet this requirement will result in prohibition of the authorized account representative for the eligible resource from further participation in the program, unless reauthorized at the discretion of the Administrator.

(c) The Administrator may freeze the general account held by an authorized account representative of an eligible resource at any time, for cause, if the Administrator determines set-aside allowances have been improperly issued, based on a misrepresentation or misstatement in an eligibility application or M&V report. The Administrator may also freeze the general account of an authorized account representative of an eligible resource pending investigation of potential misrepresentation, error, or misstatement in an eligibility application of an eligible resource, or in an M&V report for which set-aside allowances have been issued. Freezing a general account will prevent transfer of allowances out of the account.

(d) If set-aside allowances are issued for an eligible resource that is found to be ineligible, then the Administrator may take the actions in paragraphs (d)(1) through (3) of this section.

(1) Freeze the general account of the authorized account representative for an eligible resource, preventing any transfers of allowances out of the account.

(2) Revoke or deduct allowances held in the general account of the authorized account representative for an eligible resource, in a number equal to the number of allowances issued for the ineligible eligible resource.

(3) In the event that the general account of the eligible resource holds a number of allowances less than the number of set-aside allowances issued for the ineligible eligible resource, the delegated representative of an eligible resource must submit to the Administrator within 30 days a number of allowances necessary to fully account for all allowances issued for the ineligible eligible resource. Failure to meet this requirement will result in prohibition of the eligible resource from further participation in the program, unless reauthorized at the discretion of the Administrator.

(e) The Administrator may temporarily or permanently suspend issuance of set-aside allowances for an eligible resource, for the following reasons in paragraphs (e)(1) through (3) of this section.

(1) Pending investigation of potential misrepresentation, error, or misstatement in an M&V report, for which set-aside allowances have been issued, or the eligibility status of an eligible resource.

(2) In the case of repeated error or misstatements in submitted M&V reports.

(3) In the case of an intentional misrepresentation in a submitted M&V report.

Evaluation Measurement and Verification Plans, Monitoring and Verification Reports, and Verification

§ 62.16260 What are the requirements for evaluation, measurement and verification plans for eligible resources?

(a) *EM&V plan requirements.* Any EM&V plan submitted in support of the issuance of a set-aside allowance pursuant to this rule must meet the requirements of this section.

(b) *General EM&V plan criteria.* Each EM&V plan must identify the eligible resource and its approved eligibility application.

(c) *Specific EM&V plan criteria.* Each EM&V plan must provide the manner in which the electricity generated or saved by the eligible resource will be quantified, monitored and verified, and the manner of quantification, monitoring and verification must meet the criteria listed in paragraphs (c)(1) through (7) of this section, as applicable to the specific eligible resource.

(1) For a nuclear energy resource or a renewable energy resource with a nameplate capacity of 10 kW or more and for a renewable energy resource with a nameplate capacity of less than 10 kW for which metered data are available, each EM&V plan must specify that the requirements in paragraphs (c)(1)(i) through (vi) of this section must be met.

(i) The generation data are physically measured on a continuous basis using a revenue-quality meter, which means a meter used by a control area operator for financial settlements, or a meter that meets the American National Standards Institute No. C12.20., Code for Electricity Metering, metering accuracy standards, or a meter that meets an alternative equivalent standard that has been approved in advance of its use to measure generation pursuant to this regulation by the EPA.

(ii) The generating data are measured at the generator's bus bar, or, for a renewable energy resource with a nameplate capacity of less than 10 kW that is interconnected behind an individual business or household meter, the generating data were measured at the AC output of the inverter and adjusted to reflect the only energy delivered into either the transmission or distribution grid at the generator bus bar and not any energy used on-site at the generator.

(iii) The generation data from only one eligible resource generating unit may be associated with each meter, and generation data may not be aggregated, unless all the following provisions are met:

(A) All of the generating units have the same essential generation characteristics;

(B) All of the generating units are located in the same State;

(C) The nameplate capacity of the individual units being aggregated is each less than 150 kW, and units collectively do not exceed a total nameplate capacity of 1 MW when aggregated, or alternative requirements approved by the EPA in connection with the specific State plan pursuant to which that EM&V plan or M&V report is submitted; and

(D) The generation data are measured by the same type of meter that is subject to the same maintenance and quality assurance procedures.

(iv) The generation data are collected electronically and telemetered from the generator to its control area operator and verified through a control area energy accounting or settlement process which occurs at least monthly, unless the generation unit does not go through a control area operator, in which case the generation data must be collected by manual meter readings conducted by an independent verifier that is either not affiliated with the owner or operator of the qualifying renewable energy generating resource or is precluded pursuant to the relevant State plan from the ability to transfer or retire set-aside allowances issued to that qualifying renewable energy generating resource or, if the generating unit is less than 10 kw and does not generate enough electricity to enable monthly reporting, then the data may be self-reported and reported no less than annually.

(v) The generation data serve a load that otherwise would have been served by the grid if not for the generator. Specifically:

(A) Set-aside allowances shall not be issued for energy generation used to supply the ancillary equipment used to operate a generating station or substation (''station service'') or parasitic load on the generator's side of the point of interconnection; and

(B) For generators interconnected to transmission systems and with on-site loads other than station service drawing generation before the metering point, set-aside allowances may be issued for on-site load, if the owner or operator of the eligible resource can demonstrate that the metering used is capable of distinguishing between on-site load and station service.

(vi) Any other requirements approved by the EPA in connection with the specific State plan pursuant to which that EM&V plan is submitted.

(2) For a renewable energy resource with a nameplate capacity of less than 10 kW and that does not have a meter, each EM&V plan must require that the following requirements in paragraphs (c)(2)(i) through (vii) of this section are met.

(i) Metered data are unavailable.

(ii) At least 1 MW of net energy output is generated to the distribution or transmission system over a continuous 365-day period.

(iii) The generation data may not be aggregated, unless the following provisions are met:

(A) All of the generating units have the same essential generation characteristics;

(B) All of the generating units are located in the same State;

(C) The nameplate capacity of the individual units being aggregated is each less than 150 kW, and units collectively do not exceed a total nameplate capacity of 1 MW when aggregated, or alternative requirements approved by the EPA in connection with the specific State plan pursuant to which that EM&V plan or M&V report is submitted; and

(D) The generation data are measured by the same generation estimating software or algorithms.

(iv) The generation data are measured on at least a monthly basis using generation estimating software or algorithms that are based on an on-site inspection prior to interconnection and a resource study (wind, shading, solar irradiance, depending on the resource), or engineering information that takes into account the capacity, age, and type of qualifying energy generating resource, and all input parameters and assumptions must be clearly delineated, or if the generating unit does not generate enough electricity to enable monthly reporting, then the data may be reported no less than annually.

(v) The generation data are self-reported to the distribution utility through an electronic internet-based portal with software that reports total and hourly generation.

(vi) The generation data serves a load that otherwise would have been served by the grid if not for the generator. The set-aside allowance is only based on generation transferred from the eligible resource to the transmission or distribution grid, and is not based on the generation used on-site by the customer.

(vii) Any other requirements approved by the EPA in connection with the specific State plan pursuant to which that EM&V plan is submitted.

(3) For qualified biomass feedstocks used, in addition to the requirements of paragraph (c)(1) or (2) of this section, whichever section is applicable, each EM&V plan must demonstrate that the requirements approved by the EPA for that biomass feedstock, and its associated biogenic CO_2, have been met.

(4) For a waste-to-energy resource, in addition to the requirements of paragraph (c)(1) or (2) of this section, as applicable, and paragraph (c)(3) of this section, each EM&V plan must specify:

(i) The total net energy generation from the resource in MWh;

(ii) The method for determining the specific portion of the total net energy output from the resource that is related to the biogenic portion of the waste; and

(iii) The net energy output is measured with the relevant method approved by the EPA in connection with the specific State plan pursuant to which that EM&V plan is submitted demonstrates that the requirements approved by the EPA in connection with that State plan have been met.

(5) For a combined heat and power unit, in addition to the requirements of paragraphs (c)(1) or (2) of this section,

as applicable, and paragraph (c)(3) of this section, each EM&V plan must meet one of the requirements in paragraphs (c)(5)(i) through (iv) of this section, as applicable, and any other requirements approved by the EPA.

(i) If the combined heat and power unit has an electric generating capacity greater than 25 MW, then the EM&V plan must meet the requirements that apply to an affected EGU under § 62.16540 of this subpart.

(ii) If the combined heat and power unit has an electric generating capacity less than or equal to 25 MW and greater than 1 MW, and it uses only natural gas and/or distillate fuel oil, then the EM&V plan must meet the low mass emission unit CO_2 emission monitoring and reporting methodology in part 75 of this chapter.

(iii) If the combined heat and power unit has an electric generating capacity less than or equal to 25 MW and greater than 1 MW, and it uses anything other than only natural gas and/or distillate fuel oil, then the EM&V plan must meet the low mass emission unit CO_2 emission monitoring and reporting methodology in part 75 of this chapter.

(iv) If the combined heat and power unit has an electric generating capacity less than or equal to 1 MW the unit must keep monthly cumulative recordings of useful thermal output and fossil fuel input along with the determination of baseline thermal source efficiencies based on manufacturer data. For CHP units that directly serve on-site end-use electricity loads, avoided transmission and distribution (T&D) system losses can be assessed as is commonly practiced with demand-side EE.

(6) For electricity savings that avoid a transmission and distribution loss, each EM&V plan must measure the transmission and distribution loss based on the lesser of 6 percent of the site-level electricity savings measured at the end use meter or the statewide annual average transmission and distribution loss rate (expressed as a percentage) from the most recent year that is published in the US EIA State Electricity Profile expressed as a percentage. No other transmission and distribution loss factors may be used in calculating the electricity savings, including measures such as conservation voltage reduction and volt/VAR optimization.

(7) Each EM&V plan for an EE program, EE project, or EE measure must specify how each of the requirements in paragraphs (c)(7)(i) through (x) of this section will be met in quantifying the electricity savings from that EE program, EE project, or EE measure.

(i) All electricity savings must be quantified on an ex-post basis, which means after the electricity savings have occurred, or on a real-time basis, which means at the time the electricity savings are occurring. Electricity savings must not be quantified on an ex-ante basis, which means estimates of MWh savings that are generated prior to implementing the subject EE program, EE project, or EE measure, and that are not quantified using EM&V methods and procedures.

(ii) All electricity savings must be quantified and verified based on methods and procedures detailed in an industry best-practice EM&V protocol or guideline. Each EM&V plan must include a demonstration of how the best-practice protocol or guideline was selected and will be applied to the specific EE program, EE project, or EE measure covered in the EM&V plan, and an explanation of why that particular protocol or guideline was selected. Protocols and guidelines are considered to be best practice if they:

(A) Have gone through a rigorous and credible peer review process that shows the applicable methods to be valid through empirical testing; and

(B) Have been accepted and approved for use by identifiable state regulatory commissions. Examples of such protocols and guidelines that may be provided in EM&V guidance issued by the Administrator will be acceptable.

(iii) All electricity savings must be quantified as the difference between the observed electricity use and a common practice baseline (CPB), which is the equipment that would typically have been installed—or that a typical consumer or building owner would have continued using—in a given circumstance (*i.e.,* a given building type, EE program type or delivery mechanism, and geographic region) at the time of EE implementation. Examples of CPBs for specific EE programs, EE projects, EE measures, and for certain EM&V methods that may be provided in EM&V guidance issued by the Administrator will be acceptable. The EM&V plan must specify the reason the specific CPB was selected, which must include an analysis of the appropriateness of that CPB for the EE program, EE project, or EE measure covered in the EM&V plan, based on:

(A) Characteristics of the EE program, EE project, or EE measure;

(B) The delivery mechanism used to implement the EE program, EE project, or EE measure (*e.g.,* installed as part of a utility EE program versus a point-of-sale rebate);

(C) Local consumer and market characteristics;

(D) Applicable building energy codes and standards and average compliance rates; and

(E) The method applied: project-based measurement and verification (PB–MV), comparison group approaches, or deemed savings.

(iv) All electricity savings must be quantified by applying one or more of the following methods: PB–MV, comparison group approaches, or deemed savings.

(A) If a comparison group approach is used, then the EM&V plan must quantify electricity savings by taking the difference between a comparison group's electricity use and the electricity use of EE program participants. Comparison group approaches may include randomized control trials and quasi-experimental methods, as described in industry best-practice protocols and guidelines. Examples of such protocols and guidelines provided in EM&V guidance that may be issued by the Administrator will be acceptable.

(B) If deemed savings are used, then the EM&V plan must specify that the deemed savings values will only be used for the specific EE measure for which they were derived. The EM&V plan must also specify the name and Web address of the technical reference manual (TRM) in which all deemed electricity savings values will be documented. Prior to use in an EM&V plan, all TRMs must undergo a review process in which the public, stakeholders, and experts are invited—with adequate advance notification (via the internet and other social media)—to provide comment, have at least 2 months to provide comment, and in which all such comments and associated responses are made publicly available. All TRMs must also be publicly accessible over the full period of time in which they are being used in conjunction with an EM&V plan for the purpose of quantifying savings, and must be subsequently updated in the same manner at least every 3 years. The TRM must indicate, for each subject EE measure, the associated electricity savings value, the conditions under which the value can be applied (including the climate zone, building type, manner of implementation, applicable end uses, operating conditions, and effective useful life), and the manner in which the electricity savings value was quantified, which must include applicable engineering algorithms, source documentation, specific assumptions, and other relevant data to support the quantification of savings from the subject EE measure.

(v) All EE programs, EE projects, or EE measures must be quantified at time intervals (in years) sufficient to ensure that MWh savings are accurately and reliably quantified. Such time intervals must be specified and explained in the EM&V plan. Factors that must be taken into consideration when determining the appropriate time interval include the characteristics of the specific EE program, EE project, or EE measure, expected variability in electricity savings (where greater variability necessitates more frequent quantification), the expected scale and magnitude of the electricity savings (where greater quantities of savings necessitate more frequent quantification), and the experience implementing and quantifying savings from the resource (where less experience—for example, with new and innovative EE program types—necessitates more frequent quantification). The time intervals must end no sooner than the last day of the effective useful life of the EE program, EE project, or EE measure, and must last no longer than:

(A) Every 4-year intervals for building energy codes and product standards;

(B) Every 1, 2 or 3 years for public or consumer-funded EE program, EE project, or EE measure, as relevant for the type of EE program, EE project, or EE measure and factors listed in paragraph (c)(7)(v) of this section; and

(C) Annually for commercial and industrial projects, unless the resource provider can provide a reasonable justification in the EM&V plan for why an annual time interval is not feasible, and can additionally explain how the accuracy and reliability of savings values will not be lessened.

(vi) EM&V plans must specify and document how the EM&V components in paragraphs (c)(7)(vi)(A) through (E) of this section will be analyzed, considered, or otherwise addressed in the quantification and verification of electricity savings.

(A) The effects of changes in independent factors on reported electricity savings (*i.e.,* factors that are not directly related to the EE measure, such as weather, occupancy, and production levels).

(B) The effective useful life (EUL) or duration of time the EE measure is anticipated to remain in place and operable with the potential to save electricity, which must be based on the application of EM&V methods, an industry best-practice persistence study, deemed estimates of effective useful life, or a combination of all three.

(1) If deemed estimates of effective useful life are used, then they must specify the date by which the EE measure will stop saving electricity.

(2) If industry best-practices persistence studies are used to modify an effective-useful-life value, then they must be conducted at least every 5 years.

(C) The potential sources of double counting, and the associated steps for avoiding and correcting for it, such as:

(1) For an EE program or EE project with identified participants, track the type and number of EE measures implemented at the utility-customer level.

(2) For an EE program or EE project without identified participants, such as point-of-sale rebates and retailer or manufacturer incentive programs, track applicable vendor, retailer, and manufacturer data.

(3) For EE programs (such as those implemented by a utility) and EE projects (such as those implemented by an energy service company) that both have identified participants, use tracking data to avoid and correct for double counting that may occur across the two; and

(4) For EE programs with identified participants and those without (such as retail incentives to purchase energy-efficient equipment), use EE program tracking data for the former and use applicable vendor, retailer, and manufacturer data for the latter to avoid and correct for double counting that may occur across the two.

(D) The EE savings verification approaches for ensuring that EE measures have been properly installed, are operating as intended, and therefore have the potential to save electricity, including how verification will be carried out within the first year of implementation of the EE program, EE project, or EE measure using best-practice approaches, such as physical inspections at a customer's premises, phone and mail surveys, and reviews of sales receipts and other documentation. If such approaches are documented in EM&V guidance issued by the Administrator, they will be treated as acceptable.

(E) The interactive effects of EE programs, EE projects, or EE measures on electricity usage, which are increases or decreases in electricity usage at an end-use facility or premises that occurs outside of specific end-uses(s) targeted by the EE program, EE project, or EE measure (*e.g.,* lighting retrofits to improve EE can reduce waste heat to the surrounding conditioned space, and therefore may increase the required electric heating load in a facility or premises).

(vii) The EM&V plan must specify how the accuracy and reliability of the electricity savings of the EE program, EE project, or EE measure will be assessed, and must discuss the rigor of the method selected to quantify the electricity savings. It must also discuss the approaches that will be used to control all relevant types of bias and to minimize the potential for systematic and random error, as well as the program- or project-specific circumstances in which such bias and error are likely to arise. Approaches to minimizing bias and error are provided in the EM&V guidance that may be issued by the Administrator will be acceptable.

(viii) If sampling will be used to quantify the electricity savings from an EE program, then the MWh estimates derived from sampling must have at least 90 percent confidence intervals whose end points are no more than +/−10 percent of the estimate, and the statistical precision of the associated estimates must be specified in the EM&V plan.

(ix) All data sources and key assumptions used to quantify electricity savings must be described in the EM&V plan.

(x) Any additional information necessary to demonstrate that the electricity savings were appropriately quantified and verified. Approaches to quantifying and verifying savings from several EE program and EE project types that are provided in EM&V guidance that may be issued by the Administrator will be acceptable.

(d) You must ensure that any EM&V plan submitted pursuant to this subpart includes the following certification:

(1) ''I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.''

(2) [Reserved]

§ 62.16265 What are the requirements for monitoring and verification reports for eligible resources?

(a) *M&V report requirements.* Any M&V report that is submitted, in support of the issuance of a set-aside allowance that can be used in accordance with § 62.16240, must meet the requirements of this section.

(b) *General M&V report criteria.* Each M&V report must include the information in paragraphs (b)(1) and (2) of this section.

(1) For the first M&V report submitted, documentation that the electricity-generating resources, electricity-saving measures, or practices were installed or implemented consistent with the description in the approved eligibility application required in § 62.16245(a)(3).

(2) For each M&V report submitted:

(i) Identification of the time period covered by the M&V report;

(ii) A description of how relevant quantification methods, protocols, guidelines, and guidance specified in the EM&V plan were applied during the reporting period to generate the quantified MWh of generation or MWh of electricity savings;

(iii) Documentation (including data) of the energy generation and/or electricity savings from any activity, project, measure, or program addressed in the EM&V report, quantified and verified in MWh for the period covered by the M&V report, in accordance with its EM&V plan, and based on ex-post energy generation or savings;

(iv) Documentation of any change in the energy generation or savings capability of the eligible resource during the period covered by the M&V report and the date on which the change occurred, and either certification that the eligible resource continued to meet all eligibility requirements during the reporting period covered by the M&V report or disclosure of any material changes to the eligible resource from the description of the eligible resource in the approved eligibility application, which must include any change in the energy generation (*e.g.,* nameplate MW capacity) or electricity savings capability of the qualifying eligible resource (including the date of the change); and

(v) Documentation of any change in ownership interest of the qualifying eligible resource (including the date of the change).

(c) You must ensure that any M&V report submitted pursuant to this subpart includes the following certification:

(1) ''I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.''

(2) [Reserved]

§ 62.16270 What are the requirements for verification reports?

(a) A verification report included as part of an eligibility application or an M&V report must meet the requirements of paragraph (b) of this section (for the eligibility application verification report) and paragraph (c) of this section (for the M&V report verification report) and include the following:

(1) A verification statement that sets forth the findings of the accredited independent verifier, based on the verifier's assessment of the information and data in the eligibility application or M&V report that is the subject of the verification report, including an assessment of whether the eligibility application or M&V report contains any material misstatements or material data discrepancies, and whether the submittal conforms with applicable regulatory requirements. The verification statement must clearly identify how levels of assurance and materiality are defined as part of the verifier assessment.

(2) The following statement, signed by the accredited independent verifier: ''I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my personal knowledge and/or inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.''

(b) A verification report included as part of an eligibility application must, at a minimum, describe the review conducted by the accredited independent verifier and verify each of the following:

(1) The eligibility of the eligible resource to be issued set-aside allowances pursuant to this regulation, in accordance with § 62.16245(a), including an analysis of the adequacy and validity of the information submitted by the authorized account representative to demonstrate that the eligible resource meets each applicable requirement of § 62.16245;

(2) The eligible resource is not duplicative of a resource used to meet emission standards or a state measure in another approved State plan;

(3) The eligible resource exists or the operation or activity will be implemented in the manner specified in the eligibility application;

(4) That the EM&V plan meets the requirements of § 62.16260;

(5) Disclosure of any mandatory or voluntary programs to which data is reported relating to the eligible resource (*e.g.,* reporting of electric generation by a renewable energy resource to a renewable energy certificate tracking system); and

(6) Any other information required by the Administrator or that the accredited independent verifier finds, in its professional opinion, is necessary to assess the adequacy and validity of information and data supplied by the authorized account representative.

(c) A verification report included as part of an M&V report must, at a minimum, describe the review conducted by the accredited independent verifier and verify the information specified in paragraphs (c)(1) through (3) of this section.

(1) The adequacy and validity of the information and data submitted in the submittal by the authorized account representative to quantify eligible MWh of electric generation or electricity savings during the period for which the authorized account representative seeks issuance of set-aside allowances, as well as all supporting information and data identified in the EM&V plan and M&V report. This analysis must include a quality assurance and quality control check of the data and ensure that all generation or savings data is within a technically feasible range for that specific eligible resource.

(i) For metered generation, the data validity check must compare reported electricity generation to an engineering estimate of the maximum generation potential of the qualified renewable energy resource, based on, at a minimum, its maximum nameplate capacity in MW and the number of days since the prior cumulative meter reading was entered in the allowance tracking system. If the data entered exceeds the estimated technically feasible generation, then the reported data and the estimate must be analyzed in the verification report.

(ii) For all electricity generated or saved, the accredited independent verifier must describe the likely source of any data discrepancy and determine in the verification report any MWh generated or saved.

(2) The M&V report meets the requirements of § 62.16265.

(3) Any other information required by the Administrator or that the accredited independent verifier finds, in its professional opinion, is necessary to assess the adequacy and validity of information and data supplied by the authorized account representative.

§ 62.16275 What is the accreditation procedure for independent verifiers?

(a) Only Administrator-accredited independent verifiers may provide a verification report for an eligibility application or M&V report.

(b) Applications for accreditation must follow a procedure and form specified by the Administrator which includes a demonstration by the verifier that it meets the requirements in paragraph (c) of this section.

(c) Independent verifiers must meet each of the requirements in paragraphs (c)(1) through (6) of this section to be accredited.

(1) Independent verifiers must have the skills, experience, resources (personnel and otherwise) to provide verification reports, including the following:

(i) Appropriate technical qualification (professional engineer or otherwise) to evaluate the eligible resource for which the independent verifier is seeking accreditation, which may include ANSI accreditation under ISO 14065 for GHG validation and verification bodies;

(ii) Appropriate auditing and accounting qualifications for financial and non-financial data monitoring, auditing, and quality assurance and quality control to evaluate the eligible resource for which the independent verifier is seeking accreditation;

(iii) Knowledge of the requirements of the Administrator's CO_2 Mass-based Trading Program regulations and related guidance;

(iv) Knowledge of the eligible resource categories for which the independent verifier is seeking accreditation, including relevant aspects of the design, operation, and related energy generation or electricity savings monitoring and reporting approaches for such eligible resources; and

(v) Capability to perform key verification activities, such as development of a verification report; site visits; review and recalculation of reported data; review of data management systems; review of quantification methods used in accordance with an approved EM&V plan; preparation of a verification opinion, list of findings, and verification report; and internal review of the verification findings and report.

(2) Independent verifiers must document, in the application for accreditation, the independent verifiers that will provide verification services, including lead verifiers, key personnel and any contractors or subcontractors (collectively, accredited independent verification team) and demonstrate that they meet the requirements of paragraph (c)(1) of this section. Once accredited, only the accredited independent verification team identified in the accreditation application and accredited by the State may provide a verification report.

(3) An independent verifier must specify the eligible resource categories for which it is seeking accreditation, and an accredited independent verifier may only provide verification services related to an eligible resource category for which it is accredited.

(4) Prospective independent verifiers must meet the requirements of § 62.16280(d) through (f) and demonstrate that they have in place adequate systems and protocols to identify, disclose and avoid potential conflicts of interest.

(5) An accredited independent verifier must not be debarred, suspended, or proposed for debarment pursuant to the Government-wide Debarment and Suspension regulations, 40 CFR part 32 of this chapter, or the Debarment, Suspension and Ineligibility provisions of the Federal Acquisition Regulations, 48 CFR part 9, subpart 9.4.

(6) An accredited independent verifier must maintain, for its employees, and ensure the maintenance of, for any parties that it employs, professional liability insurance, as defined in 31 CFR 50.5(q), through an insurance provider that possesses a financial strength rating in the top four categories from either Standard & Poor's or Moody's, specifically, AAA, AA, A or BBB for Standard & Poor's, and Aaa, Aa, A, or Baa for Moody's. Any entity covered by this paragraph must disclose the level of professional liability insurance they possess when entering into contracts to provide verification services pursuant to this regulation.

(d) *Requirements for maintenance of accreditation status.*

(1) Accredited independent verifiers must meet the requirements of § 62.16280 when providing verification services for an authorized account representative.

(2) The instances specified in § 62.16280(d) are cause for revocation of a verifier's accreditation.

§ 62.16280 What are the procedures accredited independent verifiers must follow to avoid conflict of interest?

(a) Accredited independent verifiers must not provide verification services for any eligible resource for which it has a conflict of interest (COI), which means:

(1) Accredited independent verifiers must have, or have had, no direct or indirect financial interest in, or other financial relationships with, an eligible resource, or any prospective eligible resource, for which they seek to provide a verification report;

(2) Accredited independent verifiers must have, or have had, no direct or indirect organizational or personal relationships with an eligible resource, that would impact their impartiality in assessing the validity and accuracy of the information in an eligibility application or M&V report;

(3) Accredited independent verifiers must have, or have had, no role in the development and implementation of an eligible resource for which an authorized account representative seeks issuance of set-aside allowances, beyond the provision of verification services;

(4) Accredited independent verifiers must not be compensated, financially or otherwise, directly or indirectly, on the basis of the content of its verification report (including eligibility approval of an eligible resource, the quantified and verified MWh in an M&V report, set-aside allowance issuance, or the number of set-aside allowances issued);

(5) Accredited independent verifiers must not own, buy, sell, or hold set-aside allowances, or other financial derivatives related to set-aside allowances, or have a financial relationship with other parties that own, buy, sell, or hold set-aside allowances or other related financial derivatives;

(6) An accredited independent verifier must not be incapable of providing an impartial verification report for any other reason; and

(7) An accredited independent verifier must ensure that the subject of any verification report must not have the opportunity to review or influence any draft or final verification report before its submittal to the Administrator, and the accredited independent verifier must share any drafts of its reports with the Administrator at the same time as it shares them with the subject of the report.

(b) A contract with an eligible resource for the provision of verification services will not constitute a COI.

(c) Verification reports must include an attestation by the accredited independent verifier that it evaluated and disclosed to the Administrator any potential COI related to an eligible resource.

(d) Prior to engaging for the provision of verification services, an accredited independent verifier must demonstrate that it has no COI related to the eligible resource, as specified in paragraph (a) of this section. If a COI is identified for a person or persons within an accredited independent verifier for a specific subject or verification, in accordance with paragraphs (e) and (f) of this section, then an accredited independent verifier may propose to the Administrator steps that will be taken to eliminate the COI, which include prohibiting the person or persons with the conflict from any involvement in the matter subject to the conflict, including verification services, access to information related to the verification services, access to any draft or final verification reports, any communications with the person(s) conducting the verification services. In no instance shall an accredited independent verifier engage in verification services for an eligible resource without the approval of the Administrator.

(e) Prior to engaging in verification services and writing a verification report, an accredited independent verifier must disclose to the Administrator all information necessary for the Administrator to evaluate a potential COI (including information concerning its ownership, past and current clients, related entities, as well as any other facts or circumstances that have the potential to create a COI).

(f) Accredited verifiers have an ongoing obligation to disclose to the Administrator any facts or circumstances that may give rise to a COI as defined in paragraph (a) of this section.

(g) The Administrator may reject a verification report from an accredited independent verifier, if the Administrator determines that the accredited independent verifier has a COI as defined in paragraph (a) of this section. If the Administrator rejects an accredited independent verifier report for such reasons, then the eligibility application or M&V report submittal shall be deemed incomplete and set-aside allowances must not be issued pursuant to it.

§ 62.16285 What is the process for the revocation of accreditation status for an independent verifier?

(a) The Administrator may revoke the accreditation of an independent verifier at any time for cause, including for the reasons specified in paragraphs (a)(1) through (4) of this section.

(1) Failure to fully disclose any issues that may lead to a COI with respect to an eligible resource, or other related entity, in accordance with § 62.16280(d) through (f).

(2) The accredited independent verifier is no longer qualified to provide verification services.

(3) Negligence in the conduct of verification activities, or neglect of responsibilities pursuant to the requirements of §§ 62.16270, 62.16275, and 62.16280.

(4) Intentional misrepresentation of data in a verification report.

(b) [Reserved]

Designated Representatives

§ 62.16290 How are designated representatives and alternate designated representatives authorized, and what role do authorized designated representatives and alternate designated representatives play?

(a) Except as provided under § 62.16300, each facility, including all affected EGUs at the facility, shall have one and only one designated representative, with regard to all matters under the CO_2 Mass-based Trading Program.

(1) The designated representative shall be selected by an agreement binding on the owners and operators of the facility and all affected EGUs at the facility and must act in accordance with the certification statement in § 62.16305(a)(4)(iii).

(2) Upon and after receipt by the Administrator of a complete certificate of representation under § 62.16305:

(i) The designated representative shall be authorized and shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each owner and operator of the facility and each affected EGU at the facility in all matters pertaining to the CO_2 Mass-based Trading Program, notwithstanding any agreement between the designated representative and such owners and operators; and

(ii) The owners and operators of the facility and each affected EGU at the facility shall be bound by any decision or order issued to the designated representative by the Administrator regarding the facility or any such affected EGU.

(b) Except as provided under § 62.16300, each facility may have one and only one alternate designated representative, who may act on behalf of the designated representative. The agreement by which the alternate designated representative is selected must include a procedure for authorizing the alternate designated representative to act in lieu of the designated representative.

(1) The alternate designated representative shall be selected by an agreement binding on the owners and operators of the facility and all affected EGUs at the facility and must act in accordance with the certification statement in § 62.16305(a)(4)(iii).

(2) Upon and after receipt by the Administrator of a complete certificate of representation under § 62.16305:

(i) The alternate designated representative must be authorized;

(ii) Any representation, action, inaction, or submission by the alternate designated representative shall be deemed to be a representation, action, inaction, or submission by the designated representative; and

(iii) The owners and operators of the facility and each affected EGU at the facility shall be bound by any decision or order issued to the alternate designated representative by the Administrator regarding the facility or any such affected EGU.

(c) Except in this section, § 62.16375, and §§ 62.16295 through 62.16315, whenever the term ‘‘designated representative’’ (as distinguished from the term ‘‘common designated representative’’) is used in this subpart, the term shall be construed to include the designated representative or any alternate designated representative.

§ 62.16295 What responsibilities do designated representatives and alternate designated representatives hold?

(a) Except as provided under § 62.16315 concerning delegation of authority to make submissions, each submission under the CO_2 Mass-based Trading Program shall be made, signed, and certified by the designated representative or alternate designated representative for each facility and affected EGU for which the submission is made. Each such submission must include the following certification statement by the designated representative or alternate designated representative: ‘‘I am authorized to make this submission on behalf of the owners and operators of the facility or affected EGUs for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.''

(b) The Administrator will accept or act on a submission made for a facility or an affected EGU only if the submission has been made, signed, and certified in accordance with paragraph (a) of this section and § 62.16315.

§ 62.16300 What are the processes for changing designated representative, alternate designated representative, owners and operators, and affected EGUs at the facility?

(a) *Changing designated representative.* The designated representative may be changed at any time upon receipt by the Administrator of a superseding complete certificate of representation under § 62.16305. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous designated representative before the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new designated representative and the owners and operators of the facility and the affected EGUs at the facility.

(b) *Changing alternate designated representative.* The alternate designated representative may be changed at any time upon receipt by the Administrator of a superseding complete certificate of representation under § 62.16305. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous alternate designated representative before the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new alternate designated representative, the designated representative, and the owners and operators of the facility and the affected EGUs at the facility.

(c) *Changes in owners and operators.* (1) In the event an owner or operator of a facility or an affected EGU at the facility is not included in the list of owners and operators in the certificate of representation under § 62.16305, such owner or operator shall be deemed to be subject to and bound by the certificate of representation, the representations, actions, inactions, and submissions of the designated representative and any alternate designated representative of the facility or affected EGU, and the decisions and orders of the Administrator, as if the owner or operator were included in such list.

(2) Within 30 days after any change in the owners and operators of a facility or an affected EGU at the facility, including the addition or removal of an owner or operator, the designated representative or any alternate designated representative must submit a revision to the certificate of representation under § 62.16305 amending the list of owners and operators to reflect the change.

(d) *Changes in affected EGUs at the facility.* Within 30 days of any change in which affected EGUs are located at a facility (including the addition or removal of an affected EGU), the designated representative or any alternate designated representative must submit a certificate of representation under § 62.16305 amending the list of affected EGUs to reflect the change.

(1) If the change is the addition of an affected EGU that operated (other than for purposes of testing by the manufacturer before initial installation) before being located at the facility, then the certificate of representation must identify, in a format prescribed by the Administrator, the entity from whom the affected EGU was purchased or otherwise obtained (including name, address, telephone number, and facsimile transmission number (if any)), the date on which the affected EGU was purchased or otherwise obtained, and the date on which the affected EGU became located at the facility.

(2) If the change is the removal of an affected EGU, then the certificate of representation must identify, in a format prescribed by the Administrator, the entity to which the affected EGU was sold or that otherwise obtained the affected EGU (including name, address, telephone number, email address and facsimile transmission number (if any)), the date on which the affected EGU was sold or otherwise obtained, and the date on which the affected EGU became no longer located at the facility.

§ 62.16305 What must be included in a certificate of representation?

(a) A complete certificate of representation for a designated representative or an alternate designated representative must include the following elements in a format prescribed by the Administrator:

(1) Identification of the facility, and each affected EGU at the facility, for which the certificate of representation is submitted, including facility and affected EGU names, facility category and NAICS code (or, in the absence of a NAICS code, an equivalent code), State, plant code, county, latitude and longitude, unit identification number and type, identification number and nameplate capacity (in MWe, rounded to the nearest tenth) of each generator served by each such affected EGU, actual or projected date of commencement of commercial operation, net summer capacity at the affect EGU, and a statement of whether such facility is located in Indian country. If a projected date of commencement of commercial operation is provided, then the actual date of commencement of commercial operation must be provided when such information becomes available.

(2) The name, address, email address (if any), telephone number, and facsimile transmission number (if any) of the designated representative and any alternate designated representative.

(3) A list of the owners and operators of the facility and of each affected EGU at the facility.

(4) The following certification statements by the designated representative and any alternate designated representative:

(i) ''I certify that I was selected as the designated representative or alternate designated representative, as applicable, by an agreement binding on the owners and operators of the facility and each affected EGU at the facility''; and

(ii) ''I certify that I have all the necessary authority to carry out my duties and responsibilities under the CO_2 Mass-based Trading Program on behalf of the owners and operators of the facility and of each affected EGU at the facility and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions and by any decision or order issued to me by the Administrator regarding the facility or unit.''

(iii) ''Where there are multiple holders of a legal or equitable title to, or a leasehold interest in, an affected EGU, or where a utility or industrial customer purchases power from an affected EGU under a life-of-the-unit, firm power contractual arrangement, I certify that: I have given a written notice of my selection as the 'designated representative' or 'alternate designated representative', as applicable, and of the agreement by which I was selected to each owner and operator of the facility and of each affected EGU at the facility; and CO_2 allowances and proceeds of transactions involving CO_2 Mass-based Trading allowances will be deemed to be held or distributed in proportion to each holder's legal, equitable, leasehold, or contractual reservation or entitlement, except that, if such multiple holders have expressly provided for a different distribution of CO_2 allowances by contract, then CO_2 allowances and proceeds of transactions involving CO_2 Mass-based Trading allowances will be deemed to be held or distributed in accordance with the contract.''

(5) The signature of the designated representative and any alternate designated representative and the dates signed.

(b) Unless otherwise required by the Administrator, documents of agreement referred to in the certificate of representation shall not be submitted to the Administrator. The Administrator shall not be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

§ 62.16310 What is the Administrator's role in objections concerning designated representatives and alternate designated representatives?

(a) Once a complete certificate of representation under § 62.16305 has been submitted and received, the Administrator will rely on the certificate of representation unless and until a superseding complete certificate of representation under § 62.16305 is received by the Administrator.

(b) Except as provided in paragraph (a) of this section, no objection or other communication submitted to the Administrator concerning the authorization, or any representation, action, inaction, or submission, of a designated representative or alternate designated representative shall affect any representation, action, inaction, or submission of the designated representative or alternate designated representative or the finality of any decision or order by the Administrator under the CO_2 Mass-based Trading Program.

(c) The Administrator will not adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of any designated representative or alternate designated representative, including private legal disputes concerning the proceeds of CO_2 allowance transfers.

§ 62.16315 What process must designated representatives and alternate designated representatives follow to delegate their authority?

(a) A designated representative may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(b) An alternate designated representative may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(c) In order to delegate authority to a natural person to make an electronic submission to the Administrator in accordance with paragraph (a) or (b) of this section, the designated representative or alternate designated representative, as appropriate, must submit to the Administrator a notice of delegation, in a format prescribed by the Administrator, that includes the elements in paragraphs (c)(1) through (4) of this section.

(1) The name, address, email address, telephone number, and facsimile transmission number (if any) of such designated representative or alternate designated representative.

(2) The name, address, email address, telephone number, and facsimile transmission number (if any) of each such natural person (referred to in this section as an ''agent'').

(3) For each such natural person, a list of the type or types of electronic submissions under paragraph (a) or (b) of this section for which authority is delegated to him or her.

(4) The following certification statements by such designated representative or alternate designated representative:

(i) ''I agree that any electronic submission to the Administrator that is made by an agent identified in this notice of delegation and of a type listed for such agent in this notice of delegation and that is made when I am a designated representative or alternate designated representative, as appropriate, and before this notice of delegation is superseded by another notice of delegation under § 62.16315(d) shall be deemed to be an electronic submission by me''; and

(ii) ''Until this notice of delegation is superseded by another notice of delegation under § 62.16315(d), I agree to maintain an email account and to notify the Administrator immediately of any change in my email address unless all delegation of authority by me under § 62.16315 is terminated.''

(d) A notice of delegation submitted under paragraph (c) of this section shall be effective, with regard to the designated representative or alternate designated representative identified in such notice, upon receipt of such notice by the Administrator and until receipt by the Administrator of a superseding notice of delegation submitted by such designated representative or alternate designated representative, as appropriate. The superseding notice of delegation may replace any previously identified agent, add a new agent, or eliminate entirely any delegation of authority.

(e) Any electronic submission covered by the certification in paragraph (c)(4)(i) of this section and made in accordance with a notice of delegation effective under paragraph (d) of this section shall be deemed to be an electronic submission by the designated representative or alternate designated representative submitting such notice of delegation.

Monitoring, Recordkeeping, Reporting

§ 62.16320 How are compliance accounts and general accounts established?

(a) *Compliance accounts.* Upon receipt of a complete certificate of representation under § 62.16305, the Administrator will establish a compliance account for the facility for which the certificate of representation was submitted, unless the facility already has a compliance account. The designated representative and any alternate designated representative of the facility shall be the authorized account representative and the alternate authorized account representative respectively of the compliance account.

(b) *Retirement accounts.* (1) A retirement account, into which allowances held in a compliance account for an affected EGU are surrendered by the owner or operator of an affected EGU, for use in demonstrating compliance with its emission standards. The retirement account may only be held by the Administrator, and allowances deposited into it are permanently retired. Once an allowance is retired, the allowance shall no longer be transferable to another account in that allowance tracking system or any other allowance tracking system.

(2) [Reserved]

(c) *General accounts*—(1) *Application for a general account.* (i) Any person may apply to open a general account, for the purpose of holding and transferring CO_2 allowances, by submitting to the Administrator a complete application for a general account. Such application must designate one and only one authorized account representative and may designate one and only one alternate authorized account representative who may act on behalf of the authorized account representative.

(A) The authorized account representative and alternate authorized account representative shall be selected by an agreement binding on the persons who have an ownership interest with respect to CO_2 allowances held in the general account.

(B) The agreement by which the alternate authorized account representative is selected must include a procedure for authorizing the alternate authorized account representative to act in lieu of the authorized account representative.

(ii) A complete application for a general account must include the following elements in a format prescribed by the Administrator:

(A) Name, mailing address, email address (if any), telephone number, and facsimile transmission number (if any) of the authorized account representative and any alternate authorized account representative;

(B) An identifying name for the general account;

(C) A list of all persons subject to a binding agreement for the authorized account representative and any alternate authorized account representative to represent their ownership interest with respect to the CO_2 allowances held in the general account;

(D) The following certification statement by the authorized account representative and any alternate authorized account representative: ''I certify that I was selected as the authorized account representative or the alternate authorized account representative, as applicable, by an agreement that is binding on all persons who have an ownership interest with respect to CO_2 allowances held in the general account. I certify that I have all the necessary authority to carry out my duties and responsibilities under the CO_2 Mass-based Trading Program on behalf of such persons and that each such person shall be fully bound by my representations, actions, inactions, or submissions and by any decision or order issued to me by the Administrator regarding the general account''; and

(E) The signature of the authorized account representative and any alternate authorized account representative and the dates signed.

(iii) Unless otherwise required by the Administrator, documents of agreement referred to in the application for a general account shall not be submitted to the Administrator. The Administrator shall not be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

(2) *Authorization of authorized account representative and alternate authorized account representative.* (i) Upon receipt by the Administrator of a complete application for a general account under paragraph (c)(1) of this section, the Administrator will establish a general account for the person or persons for whom the application is submitted, and upon and after such receipt by the Administrator:

(A) The authorized account representative of the general account shall be authorized and shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each person who has an ownership interest with respect to CO_2 allowances held in the general account in all matters pertaining to the CO_2 Mass-based Trading Program, notwithstanding any agreement between the authorized account representative and such person;

(B) Any alternate authorized account representative shall be authorized, and any representation, action, inaction, or submission by any alternate authorized account representative shall be deemed to be a representation, action, inaction, or submission by the authorized account representative; and

(C) Each person who has an ownership interest with respect to CO_2 allowances held in the general account shall be bound by any decision or order issued to the authorized account representative or alternate authorized account representative by the Administrator regarding the general account.

(ii) Except as provided in paragraph (c)(5) of this section concerning delegation of authority to make submissions, each submission concerning the general account shall be made, signed, and certified by the authorized account representative or any alternate authorized account representative for the persons having an ownership interest with respect to CO_2 allowances held in the general account. Each such submission must include the following certification statement by the authorized account representative or any alternate authorized account representative: ''I am authorized to make this submission on behalf of the persons having an ownership interest with respect to the CO_2 allowances held in the general account. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.''

(iii) Except in this section, whenever the term ''authorized account representative'' is used in this subpart, the term shall be construed to include the authorized account representative or any alternate authorized account representative.

(3) Changing authorized account representative and alternate authorized account representative; changes in persons with ownership interest.

(i) The authorized account representative of a general account may be changed at any time upon receipt by the Administrator of a superseding complete application for a general account under paragraph (c)(1) of this section. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous authorized account representative before the time and date when the Administrator receives the superseding application for a general account shall be binding on the new authorized account representative and the persons with an ownership interest with respect to the CO_2 allowances in the general account.

(ii) The alternate authorized account representative of a general account may be changed at any time upon receipt by the Administrator of a superseding complete application for a general account under paragraph (c)(1) of this section. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous alternate authorized account representative before the time and date when the Administrator receives the superseding application for a general account shall be binding on the new alternate authorized account representative, the authorized account representative, and the persons with an ownership interest with respect to the CO_2 allowances in the general account.

(iii)(A) In the event a person having an ownership interest with respect to CO_2 allowances in the general account is not included in the list of such persons in the application for a general account, such person shall be deemed to be subject to and bound by the application for a general account, the representation, actions, inactions, and submissions of the authorized account representative and any alternate authorized account representative of the account, and the decisions and orders of the Administrator, as if the person were included in such list.

(B) Within 30 days after any change in the persons having an ownership interest with respect to CO_2 allowances in the general account, including the addition or removal of a person, the authorized account representative or any alternate authorized account representative must submit a revision to the application for a general account amending the list of persons having an ownership interest with respect to the

CO_2 allowances in the general account to include the change.

(4) Objections concerning authorized account representative and alternate authorized account representative.

(i) Once a complete application for a general account under paragraph (c)(1) of this section has been submitted and received, the Administrator will rely on the application unless and until a superseding complete application for a general account under paragraph (c)(1) of this section is received by the Administrator.

(ii) Except as provided in paragraph (c)(4)(i) of this section, no objection or other communication submitted to the Administrator concerning the authorization, or any representation, action, inaction, or submission of the authorized account representative or any alternate authorized account representative of a general account shall affect any representation, action, inaction, or submission of the authorized account representative or any alternate authorized account representative or the finality of any decision or order by the Administrator under the CO_2 Mass-based Trading Program.

(iii) The Administrator will not adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of the authorized account representative or any alternate authorized account representative of a general account, including private legal disputes concerning the proceeds of CO_2 allowance transfers.

(5) Delegation by authorized account representative and alternate authorized account representative. (i) An authorized account representative of a general account may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(ii) An alternate authorized account representative of a general account may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(iii) In order to delegate authority to a natural person to make an electronic submission to the Administrator in accordance with paragraph (c)(5)(i) or (ii) of this section, the authorized account representative or alternate authorized account representative, as appropriate, must submit to the Administrator a notice of delegation, in a format prescribed by the Administrator, that includes the following elements:

(A) The name, address, email address, telephone number, and facsimile transmission number (if any) of such authorized account representative or alternate authorized account representative;

(B) The name, address, email address, telephone number, and facsimile transmission number (if any) of each such natural person (referred to in this section as an ''agent'');

(C) For each such natural person, a list of the type or types of electronic submissions under paragraph (c)(5)(i) or (ii) of this section for which authority is delegated to him or her;

(D) The following certification statement by such authorized account representative or alternate authorized account representative: ''I agree that any electronic submission to the Administrator that is made by an agent identified in this notice of delegation and of a type listed for such agent in this notice of delegation and that is made when I am an authorized account representative or alternate authorized representative, as appropriate, and before this notice of delegation is superseded by another notice of delegation under § 62.16320(c)(5)(iv) shall be deemed to be an electronic submission by me''; and

(E) The following certification statement by such authorized account representative or alternate authorized account representative: ''Until this notice of delegation is superseded by another notice of delegation under § 62.16320(c)(5)(iv), I agree to maintain an email account and to notify the Administrator immediately of any change in my email address unless all delegation of authority by me under § 62.16320(c)(5) is terminated.''

(iv) A notice of delegation submitted under paragraph (c)(5)(iii) of this section shall be effective, with regard to the authorized account representative or alternate authorized account representative identified in such notice, upon receipt of such notice by the Administrator and until receipt by the Administrator of a superseding notice of delegation submitted by such authorized account representative or alternate authorized account representative, as appropriate. The superseding notice of delegation may replace any previously identified agent, add a new agent, or eliminate entirely any delegation of authority.

(v) Any electronic submission covered by the certification in paragraph (c)(5)(iii)(D) of this section and made in accordance with a notice of delegation effective under paragraph (c)(5)(iv) of this section shall be deemed to be an electronic submission by the designated representative or alternate designated representative submitting such notice of delegation.

(6) *Closing a general account.* (i) The authorized account representative or alternate authorized account representative of a general account may submit to the Administrator a request to close the account. Such request must include a correctly submitted CO_2 allowance transfer under § 62.16330 for any CO_2 allowances in the account to one or more other ATCS accounts.

(ii) If a general account has no CO_2 allowance transfers to or from the account for a 12-month period or longer and does not contain any CO_2 allowances, then the Administrator may notify the authorized account representative for the account that the account will be closed 30 days after the notice is sent. The account will be closed after the 30-day period unless, before the end of the 30-day period, the Administrator receives a correctly submitted CO_2 allowance transfer under § 62.16330 to the account or a statement submitted by the authorized account representative or alternate authorized account representative demonstrating to the satisfaction of the Administrator good cause as to why the account should not be closed.

(d) *Account identification.* The Administrator will assign a unique identifying number to each account established under paragraphs (a) through (c) of this section.

(e) *Responsibilities of authorized account representative and alternate authorized account representative.* After the establishment of a compliance account or general account, the Administrator will accept or act on a submission pertaining to the account, including, but not limited to, submissions concerning the deduction or transfer of CO_2 allowances in the account, only if the submission has been made, signed, and certified in accordance with §§ 62.16295(a) and 62.16315 or paragraphs (c)(2)(ii) and (c)(5) of this section.

§ 62.16325 When will CO_2 allowances be recorded in compliance accounts?

(a) By June 1, 2021, and by June 1 of each year prior to the beginning of each compliance period thereafter, the Administrator will record in each facility's compliance account the CO_2 allowances allocated to the affected EGUs at the facility in accordance with § 62.16240(a), or with a state allowance-distribution methodology approved under subpart UUUU of part 60 of this chapter, for the upcoming compliance period.

(b) Except as specified in paragraph (a) of this section, the Administrator will record an allocation in the appropriate ATCS account by the date on which any allocation of CO_2 allowances to a recipient must be made by or submitted to the Administrator in accordance with either § 62.16240 or with state allowance-distribution methodology approved under subpart UUUU of part 60 of this chapter.

(c) When recording the allocation of CO_2 allowances to an affected EGU or other entity in an ATCS account, the Administrator will assign each CO_2 allowance a unique serial number that will include digits identifying the year of the compliance period for which the CO_2 allowance is allocated.

(d) By December 1, 2021 and December 1 of each year thereafter, the Administrator will record in each renewable energy project's general account, the CO_2 allowances allocated from the renewable energy set-aside to the project in accordance with § 62.16245(a), for the following year.

(e) By November 1 of the first year of each compliance period beginning in 2025, and each compliance period thereafter, the Administrator will record in each facility's compliance account the CO_2 allowances allocated from the output-based set-aside to the eligible EGUs at the facility in accordance with § 62.16245(b) or with a state allowance-distribution methodology approved under subpart UUUU of part 60 of this chapter, for the following year.

§ 62.16330 How must transfers of CO_2 allowances be submitted?

(a) An authorized account representative seeking recordation of a CO_2 allowance transfer must submit the transfer to the Administrator.

(b) A CO_2 allowance transfer is correctly submitted if:

(1) The transfer includes the following elements, in a format prescribed by the Administrator:

(i) The account numbers established by the Administrator for both the transferor and transferee accounts;

(ii) The serial number of each CO_2 allowance that is in the transferor account and is to be transferred; and

(iii) The name and signature of the authorized account representative of the transferor account and the date signed; and

(2) When the Administrator attempts to record the transfer, the transferor account includes each CO_2 allowance identified by serial number in the transfer.

§ 62.16335 When will CO_2 allowance transfers be recorded?

(a) Within 5 business days (except as provided in paragraph (b) of this section) of receiving a CO_2 allowance transfer that is correctly submitted under § 62.16330, the Administrator will record a CO_2 allowance transfer by moving each CO_2 allowance from the transferor account to the transferee account as specified in the transfer.

(b) A CO_2 allowance transfer to or from a compliance account that is submitted for recordation after the allowance transfer deadline for a compliance period and that includes any CO_2 allowances allocated for any compliance period before such allowance transfer deadline will not be recorded until after the Administrator completes the deductions from such compliance account under § 62.16340 for the compliance period immediately before such allowance transfer deadline.

(c) Where a CO_2 allowance transfer is not correctly submitted under § 62.16330, the Administrator will not record such transfer.

(d) Within 5 business days of recordation of a CO_2 allowance transfer under paragraphs (a) and (b) of the section, the Administrator will notify the authorized account representatives of both the transferor and transferee accounts.

(e) Within 10 business days of receipt of a CO_2 allowance transfer that is not correctly submitted under § 62.16330, the Administrator will notify the authorized account representatives of both accounts subject to the transfer of:

(1) A decision not to record the transfer; and

(2) The reasons for such non-recordation.

§ 62.16340 How will deductions for compliance with a CO_2 emission standard occur?

(a) *Availability for deduction for compliance.* CO_2 allowances are available to be deducted for compliance with a facility's CO_2 emission standard for a compliance period only if the CO_2 allowances:

(1) Were allocated for a year in such compliance period or a prior compliance period; and

(2) Are held in the facility's compliance account as of the allowance transfer deadline for such compliance period.

(b) *Deductions for compliance.* After the recordation, in accordance with § 62.16335, of CO_2 allowance transfers submitted by the allowance transfer deadline for a compliance period, the Administrator will deduct from each facility's compliance account CO_2 allowances available under paragraph (a) of this section in order to determine whether the facility meets the CO_2 emission standard for such compliance period, as follows:

(1) Until the amount of CO_2 allowances deducted equals the number of tons of total CO_2 emissions from all affected EGUs at the facility for such compliance period; or

(2) If there are insufficient CO_2 allowances to complete the deductions in paragraph (b)(1) of this section, until no more CO_2 allowances available under paragraph (a) of this section remain in the compliance account.

(c)(1) *Identification of CO_2 allowances by serial number.* The authorized account representative for a facility's compliance account may request that specific CO_2 allowances, identified by serial number, in the compliance account be deducted for emissions or excess emissions for a compliance period in accordance with paragraph (b) or (d) of this section. In order to be complete, such request must be submitted to the Administrator by the allowance transfer deadline for such compliance period and include, in a format prescribed by the Administrator, the identification of the facility and the appropriate serial numbers.

(2) *First-in, first-out.* The Administrator will deduct CO_2 allowances under paragraph (b) or (d) of this section from the facility's compliance account in accordance with a complete request under paragraph (c)(1) of this section or, in the absence of such request or in the case of identification of an insufficient amount of CO_2 allowances in such request, on a first-in, first-out accounting basis in the following order:

(i) Any CO_2 allowances that were allocated to the affected EGUs at the facility and not transferred out of the compliance account, in the order of recordation; and then

(ii) Any CO_2 allowances that were allocated to any affected EGU or other entity and transferred to and recorded in the compliance account pursuant to this subpart, in the order of recordation.

(d) *Deductions for excess emissions.* After making the deductions for compliance under paragraph (b) of this section for a compliance period in a year in which the facility has excess emissions, the Administrator will deduct from the facility's compliance account an amount of CO_2 allowances, allocated for a compliance period in a prior year or the compliance period in the year of the excess emissions or in the immediately following year, equal to two times the number of tons of the facility's excess emissions.

(e) *Recordation of deductions.* The Administrator will record in the appropriate compliance account all deductions from such an account under paragraphs (b) and (d) of this section.

§ 62.16345 What monitoring requirements must I comply with?

(a) The owner or operator of an affected EGU must prepare a monitoring plan in accordance with the applicable provisions in § 75.53(g) and (h) of this chapter, unless such a plan is already in place under another program that requires CO_2 mass emissions to be monitored and reported according to part 75 of this chapter. You must follow the requirements described in paragraphs (a)(1) through (8) of this section to monitor emissions and net energy output at your affected EGU.

(1) For each operating hour, calculate the hourly CO_2 mass (tons) according to paragraph (a)(4) or (5) of this section, except that a complete data record is required, *i.e.,* CO_2 mass emissions must be reported for each operating hour. Therefore, substitute data values recorded under part 75 of this chapter for CO_2 concentration, stack gas flow rate, stack gas moisture content, fuel flow rate and/or gross calorific value (GCV) must be used in the calculations; and

(2) Sum all of the hourly CO_2 mass emissions values over the entire compliance period.

(3) The owner or operator of an affected EGU must install, calibrate, maintain, and operate a sufficient number of watt meters to continuously measure and record on an hourly basis net electric output. Measurements must be performed using 0.2 accuracy class electricity metering instrumentation and calibration procedures as specified under ANSI Standards No. C12.20. Further, the owner or operator of an affected EGU that is a combined heat and power facility must install, calibrate, maintain and operate equipment to continuously measure and record on an hourly basis useful thermal output and, if applicable, mechanical output, which are used with net electric output to determine net energy output (P_{net}). The owner or operator must calculate net energy output according to paragraphs (a)(6)(i)(A) and (B) of this section.

(4) The owner or operator of an affected EGU must measure and report the hourly CO_2 mass emissions (lbs) from each affected unit using the procedures in paragraphs (a)(4)(i) through (vi) of this section, except as otherwise provided in paragraph (a)(5) of this section.

(i) The owner or operator of an affected EGU must install, certify, operate, maintain, and calibrate a CO_2 continuous emissions monitoring system (CEMS) to directly measure and record CO_2 concentrations in the affected EGU exhaust gases emitted to the atmosphere and an exhaust gas flow rate monitoring system according to § 75.10(a)(3)(i) of this chapter. However, when an O_2 monitor is used this way, it only quantifies the combustion CO_2; therefore, if the EGU is equipped with emission controls that produce non-combustion CO_2 (*e.g.,* from sorbent injection), then this additional CO_2 must be accounted for, in accordance with section 3 of appendix G to part 75 of this chapter. As an alternative to direct measurement of CO_2 concentration, provided that the affected EGU does not use carbon separation (*e.g.,* carbon capture and storage), the owner or operator of an affected EGU may use data from a certified oxygen (O_2) monitor to calculate hourly average CO_2 concentrations, in accordance with § 75.10(a)(3)(iii) of this chapter. If CO_2 concentration is measured on a dry basis, then the owner or operator of the affected EGU must also install, certify, operate, maintain, and calibrate a continuous moisture monitoring system, according to § 75.11(b) of this chapter. Alternatively, the owner or operator of an affected EGU may either use an appropriate fuel-specific default moisture value from § 75.11(b) or submit a petition to the Administrator under § 75.66 of this chapter for a site-specific default moisture value.

(ii) Calculate the hourly CO_2 mass emission rate (tons/hr), either from Equation F–11 in Appendix F to part 75 of this chapter (if CO_2 concentration is measured on a wet basis), or by following the procedure in section 4.2 of Appendix F to part 75 of this chapter (if CO_2 concentration is measured on a dry basis). CO_2 mass emissions must be reported for each operating hour. Therefore, substitute data values recorded under part 75 of this chapter for CO_2 concentration, stack gas flow rate, stack gas moisture content, fuel flow rate and/or GCV must be used in the calculations.

(iii) Next, multiply each hourly CO_2 mass emission rate by the EGU or stack operating time in hours (as defined in § 72.2 of this chapter), to convert it to tons of CO_2. Multiply the result by 2000 lb/ton to convert it to lb.

(iv) The hourly CO_2 tons/hr values and EGU (or stack) operating times used to calculate CO_2 mass emissions are required to be recorded under § 75.57(e) of this chapter and must be reported electronically under § 75.64(a)(6) of this chapter, if required by a plan. The owner or operator must use these data, or equivalent data, to calculate the hourly CO_2 mass emissions.

(v) Sum all of the hourly CO_2 mass emissions values that were calculated according to procedures specified in paragraph (a)(4)(ii) of this section over the entire compliance period.

(vi) For each continuous monitoring system used to determine the CO_2 mass emissions from an affected EGU, the monitoring system must meet the applicable certification and quality assurance procedures in § 75.20 of this chapter and Appendices A and B to part 75 of this chapter.

(5) The owner or operator of an affected EGU that exclusively combusts liquid fuel and/or gaseous fuel may, as an alternative to complying with paragraph (a)(4) of this section, determine the hourly CO_2 mass emissions according to paragraphs (a)(5)(i) through (vi) of this section.

(i) Implement the applicable procedures in appendix D to part 75 of this chapter to determine hourly EGU heat input rates (MMBtu/h), based on hourly measurements of fuel flow rate and periodic determinations of the gross calorific value (GCV) of each fuel combusted. The fuel flow meter(s) used to measure the hourly fuel flow rates must meet the applicable certification and quality-assurance requirements in sections 2.1.5 and 2.1.6 of appendix D (except for qualifying commercial billing meters). The fuel GCV must be determined in accordance with section 2.2 or 2.3 of appendix D, as applicable.

(ii) For each measured hourly heat input rate, use Equation G–4 in Appendix G to part 75 of this chapter to calculate the hourly CO_2 mass emission rate (tons/hr).

(iii) Determine the hourly CO_2 mass emission rate (tons/hr) using the procedures specified in paragraph (a)(4)(ii) of this section and multiply it by the EGU or stack operating time in hours (as defined in § 72.2 of this chapter), to convert to tons of CO_2. Then, multiply the result by 2000 lb/ton to convert to lb.

(iv) The hourly CO_2 tons/hr values and EGU (or stack) operating times used to calculate CO_2 mass emissions are required to be recorded under § 75.57(e) of this chapter and must be reported electronically under § 75.64(a)(6), if required by a plan. You must use these data, or equivalent data, to calculate the hourly CO_2 mass emissions.

(v) Sum all of the hourly CO_2 mass emissions values (lb) that were calculated according to procedures specified in paragraph (a)(5)(iii) of this section over the entire compliance period.

(vi) The owner or operator of an affected EGU may determine site-specific carbon-based F-factors (F_c) using Equation F–7b in section 3.3.6 of appendix F to part 75 of this chapter, and may use these F_c values in the emissions calculations instead of using the default F_c values in the Equation G–4 nomenclature.

(6) The owner or operator of an affected EGU must install, calibrate, maintain, and operate a sufficient number of watt meters to continuously measure and record on an hourly basis net electric output. Measurements must be performed using 0.2 accuracy class electricity metering instrumentation and calibration procedures as specified under ANSI Standards No. C12.20. Further, the owner or operator of an affected EGU that is a combined heat and power facility must install, calibrate, maintain and operate equipment to continuously measure and record on an hourly basis useful thermal output and, if applicable, mechanical output, which are used with net electric output to determine net energy output. The owner or operator must calculate net energy output according to paragraph (a)(6)(i) of this section.

(i) For each operating hour of a compliance period that was used in paragraph (a)(4) or (5) of this section to calculate the total CO_2 mass emissions, you must determine P_{net} (the corresponding hourly net energy output in MWh) according to the procedures in paragraphs (a)(6)(i)(A) and (B) of this section, as appropriate for the type of affected EGU(s). For an operating hour in which a valid CO_2 mass emissions value is determined according to paragraph (a)(4) or (5) of this section, if there is no gross or net electrical output, but there is mechanical or useful thermal output, you must still determine the net energy output for that hour. In addition, for an operating hour in which a valid CO_2 mass emissions value is determined according to paragraph (a)(4) or (5) of this section, but there is no (*i.e.,* zero) gross electrical, mechanical, or useful thermal output, you must use that hour in the compliance determination. For hours or partial hours where the gross electric output is equal to or less than the auxiliary loads, net electric output must be counted as zero for this calculation.

(A) Calculate P_{net} for your affected EGU using the following equation. All terms in the equation must be expressed in units of megawatt-hours (MWh). To convert each hourly net energy output value reported under part 75 of this chapter to MWh, multiply by the corresponding EGU or stack operating time.

$$P_{net} = \frac{(Pe)_{ST} + (Pe)_{CT} + (Pe)_{IE} - (Pe)_A}{TDF} + [(Pt)_{PS} + (Pt)_{HR} + (Pt)_{IE}]$$

Where:

P_{net} = Net energy output of your affected EGU in MWh.

$(Pe)_{ST}$ = Electric energy output plus mechanical energy output (if any) of steam turbines in MWh.

$(Pe)_{CT}$ = Electric energy output plus mechanical energy output (if any) of stationary combustion turbine(s) in MWh.

$(Pe)_{IE}$ = Electric energy output plus mechanical energy output (if any) of your affected EGU's integrated equipment that provides electricity or mechanical energy to the affected EGU or auxiliary equipment in MWh.

$(Pe)_A$ = Electric energy used for any auxiliary loads in MWh.

$(Pt)_{PS}$ = Useful thermal output of steam (measured relative to SATP conditions as defined in § 62.16375, as applicable) that is used for applications that do not generate additional electricity, produce mechanical energy output, or enhance the performance of the affected EGU. This is calculated using the equation specified in paragraph (a)(6)(i)(B) of this section in MWh.

$(Pt)_{HR}$ = Non steam useful thermal output (measured relative to SATP conditions as defined in § 62.16375, as applicable) from heat recovery that is used for applications other than steam generation or performance enhancement of the affected EGU in MWh.

$(Pt)_{IE}$ = Useful thermal output (relative to SATP conditions as defined in § 62.16375, as applicable) from any integrated equipment that is used for applications that do not generate additional steam, electricity, produce mechanical energy output, or enhance the performance of the affected EGU in MWh.

TDF = Electric Transmission and Distribution Factor of 0.95 for a combined heat and power affected EGU where at least on an annual basis 20.0 percent of the total net energy output consists of electric or direct mechanical output and 20.0 percent of the total net energy output consists of useful thermal output on a 12-operating month rolling average basis, or 1.0 for all other affected EGUs.

(B) If applicable to your affected EGU (for example, for combined heat and power), you must calculate $(Pt)_{PS}$ using the following equation:

$$(Pt)_{PS} = \frac{Q_m \times H}{CF}$$

Where:

$(Pt)_{ps}$ = Useful thermal output of steam (measured relative to SATP conditions as defined in § 62.16375, as applicable) that is used for applications that do not generate additional electricity, produce mechanical energy output, or enhance the performance of the affected EGU.

Q_m = Measured steam flow in kilograms (kg) (or pounds (lb)) for the operating hour.

H = Enthalpy of the steam at measured temperature and pressure (relative to SATP conditions as defined in § 62.16375 or the energy in the condensate return line, as applicable) in Joules per kilogram (J/kg) (or Btu/lb).

CF = Conversion factor of 3.6×10^9 J/MWh or 3.413×10^6 Btu/MWh.

(ii) [Reserved]

(7) In accordance with § 60.13(g), if two or more affected EGUs implementing the continuous emissions monitoring provisions in paragraph (a)(1) of this section share a common exhaust gas stack and are subject to the same emissions standard, then the owner or operator may monitor the hourly CO_2 mass emissions at the common stack in lieu of monitoring each EGU separately. If an owner or operator of an affected EGU chooses this option, then the hourly net electric output for the common stack must be the sum of the hourly net electric output of the individual affected facility and the operating time must be expressed as ''stack operating hours'' (as defined in § 72.2 of this chapter).

(8) In accordance with § 60.13(g), if the exhaust gases from an affected EGU implementing the continuous emissions monitoring provisions in paragraph (a)(3) of this section are emitted to the atmosphere through multiple stacks (or if the exhaust gases are routed to a common stack through multiple ducts and you elect to monitor in the ducts), the hourly CO_2 mass emissions and the ''stack operating time'' (as defined in § 72.2 of this chapter) at each stack or duct must be monitored separately. In this case, the owner or operator of an affected EGU must determine compliance with an applicable emissions standard by summing the CO_2 mass emissions measured at the individual stacks or ducts and dividing by the net energy output for the affected EGU.

(b) [Reserved]

§ 62.16350 May I bank CO_2 annual allowances for future use or transfer?

(a) A CO_2 allowance may be banked for future use or transfer in a compliance account or a general account in accordance with paragraph (b) of this section.

(b) Any CO_2 allowance that is held in a compliance account or a general account will remain in such account unless and until the CO_2 allowance is deducted or transferred under §§ 62.16240(b), 62.16335, 62.16340, 62.16355, or 62.16370.

§ 62.16355 How does the Administrator process account errors?

The Administrator may, at his or her sole discretion and on his or her own motion, correct any error in any ATCS account. Within 10 business days of making such correction, the Administrator will notify the authorized account representative for the account.

§ 62.16360 What are my reporting, notification and submission requirements?

(a) You must prepare and submit reports according to paragraphs (a) through (e) of this section, as applicable.

(1) You must meet all applicable reporting requirements and submit reports as required under subpart G of part 75 of this chapter and you must include the following information, as applicable in the quarterly reports:

(i) The hourly CO_2 mass emission rate value (tons/hr) and unit (or stack) operating time, as monitored and reported according to part 75 of this chapter, for each unit or stack operating hour in the compliance period;

(ii) The calculated CO_2 mass emissions (tons) for each unit or stack operating hour in the compliance period;

(iii) The sum of the CO_2 mass emissions (tons) for all of the unit or stack operating hours in the compliance period;

(iv) The net electric output and the net energy output (P_{net}) values for each unit or stack operating hour in the compliance period;

(v) The sum of the hourly net energy output values for all of the unit or stack operating hours in the compliance period; and

(vi) If the report covers the final quarter of a compliance period, then you must include the CO_2 emission standard with which your affected EGU must comply, the affected EGU's calculated emission performance as a cumulative mass in units of the emission standard required, and if an affected EGU is complying with an emission standard by using allowances, then the designated representative must include in their report a list of all unique allowance serial numbers retired in the compliance period, and, for each allowance, the date an allowance was surrendered and retired. If set-aside allowances were used from an eligible resource by an affected EGU to comply with its emission standard, then the designated representative must include in their report the eligible resource identification information sufficient to demonstrate that it meets the requirements of § 62.16245 and qualifies to be issued allowance set-asides (including location, type of qualifying generation or savings, date commenced generating or saving, and date of generation or savings for which the allowance was issued).

(2) [Reserved]

(b) The designated representative of each affected EGU at the facility must make all submissions required under the CO_2 Mass-based Trading Program, except as provided in § 62.16315. This requirement does not change, create an exemption from, or otherwise affect the responsible official submission requirements under a title V operating permit program in parts 70 and 71 of this chapter.

(c) You must submit all electronic reports required under paragraph (a) of this section using the Emissions Collection and Monitoring Plan System (ECMPS) Client Tool provided by the Clean Air Markets Division in the Office of Atmospheric Programs of EPA.

(d) For affected EGUs under this subpart that are not in the Acid Rain Program, you must also meet the reporting requirements and submit reports as required under subpart G of part 75 of this chapter, to the extent that those requirements and reports provide applicable data for the compliance demonstrations required under this subpart.

(e) If your affected EGU captures CO_2 to meet the applicable emission standard, then you must report in accordance with the requirements of 40 CFR part 98, subpart PP, of this chapter and either:

(1) Report in accordance with the requirements of 40 CFR part 98, subpart RR, of this chapter, if injection occurs on-site; or

(2) Transfer the captured CO_2 to an EGU or facility that reports in accordance with the requirements of 40 CFR part 98, subpart RR, of this chapter, if injection occurs off site.

(f) You must prepare and submit notifications specified in § 75.61 of this chapter, as applicable to your affected EGUs.

§ 62.16365 What are my recordkeeping requirements?

(a) The owner or operator of each affected EGU must maintain the records, as described in paragraphs (a)(1) and (2) of this section, for at least 5 years following the date of each compliance period, occurrence, measurement, maintenance, corrective action, report, or record.

(1) The owner or operator of an affected EGU must maintain each record on site for at least 2 years after the date of each compliance period, compliance true-up period, occurrence, measurement, maintenance, corrective action, report, or record, whichever is latest, according to § 60.7 of this chapter. The owner or operator of an affected EGU may maintain the records off site and electronically for the remaining year(s).

(2) The owner or operator of an affected EGU must keep all of the following records:

(i) All emissions monitoring information, in accordance with this subpart;

(ii) Copies of all reports, compliance certifications, documents, data files, calculations and methods, other submissions and all records made or required under, or to demonstrate compliance with an affected EGU's emission standard under § 62.16220 and any other requirements of, the CO_2 Mass-based Trading Program;

(iii) Data that is required to be recorded by 40 CFR part 75, subpart F, of this chapter; and

(iv) Data with respect to any allowances used by the affected EGU in its compliance demonstration including the information in paragraphs (a)(2)(iv)(A) and (B) of this section.

(A) All documents related to any set-aside allowances used in a compliance demonstration, including each eligibility application, EM&V plan, M&V report, and independent verifier verification report associated with the issuance of each specific set-aside allowance, and each regulatory approval and any documentation that supports the issuance of each set-aside allowance by the Administrator.

(B) All records and reports relating to the surrender and retirement of allowances for compliance with this regulation, including the date each individual allowance with a unique serial identification number was surrendered and/or retired.

(b) [Reserved]

§ 62.16370 What actions may the Administrator take on submissions?

(a) The Administrator may review and conduct independent audits concerning any submission under the CO_2 Mass-based Trading Program and make appropriate adjustments of the information in the submission.

(b) The Administrator may deduct CO_2 allowances from or transfer CO_2 allowances to a compliance account, based on the information in a submission, as adjusted under paragraph (a) of this section, and record such deductions and transfers.

Definitions

§ 62.16375 What definitions apply to this subpart?

The terms used in this subpart have the meanings set forth in this section as follows:

Acid Rain Program means a multi-state SO_2 and NO_X air pollution control and emission reduction program established by the Administrator under title IV of the Clean Air Act and parts 72 through 78 of this chapter.

Administrator means the Administrator of the United States Environmental Protection Agency or his or her delegate, or the authorized state official under an approved state plan that incorporates this subpart.

Affected electric generating unit or *Affected EGU* means any steam generating unit, IGCC, or stationary combustion turbine that meets the applicability requirements in §§ 60.5840(b) and 60.5845 of this chapter. An affected EGU is not an eligible resource.

Allocate or allocation means, with regard to CO_2 allowances, the determination by the Administrator, State, or permitting authority, in accordance with this subpart or any state allowance-distribution methodology submitted by the State and approved by the Administrator under § 62.16245, to:

(1) An affected EGU;

(2) A renewable energy set-aside;

(3) An output-based set-aside; or

(4) Any other entity specified by the Administrator.

Allowable CO_2 emission rate means, for an affected EGU, the most stringent state or federal CO_2 emission rate limit (in lb/MWh or, if in lb/mmBtu, converted to lb/MWh by multiplying it by the affected EGU's heat rate in mmBtu/MWh) that is applicable to the affected EGU and covers the longest averaging period not exceeding 1 year.

Allowance system means a control program under which the owner or operator of each affected EGU is required to hold an authorization for each specified unit of carbon dioxide emitted from that facility during a specified period and which limits the total amount of such authorizations available to be held for carbon dioxide for a specified period and allows the transfer of such authorizations not used to meet the authorization-holding requirement.

Allowance Tracking and Compliance System (ATCS) means the system by which the Administrator records allocations, deductions, and transfers of CO_2 allowances under the CO_2 Mass-based Trading Program. Such allowances are allocated, recorded, held, deducted, or transferred only as whole allowances.

Allowance transfer deadline means, for a compliance period in a given year, midnight of May 1 (if it is a business day), or midnight of the first business day thereafter (if May 1 is not a business day), immediately after such compliance period and is the deadline by which a CO_2 allowance transfer must be submitted for recordation in a facility's compliance account in order to be available for use in complying with the facility's CO_2 emission standard for such compliance period in accordance with §§ 62.16220 and 62.16340.

Alternate designated representative means, for a CO_2 Mass-based Trading Program facility and each affected EGU at the facility, the natural person who is authorized by the owners and operators of the facility and all such affected EGUs at the facility, in accordance with this subpart, to act on behalf of the designated representative in matters pertaining to the CO_2 Mass-based Trading Program. If the facility is also subject to the Acid Rain Program, TR NO_X Annual Trading Program, TR NO_X Ozone Season Trading Program, TR SO_2 Group 1 Trading Program, or TR SO_2 Group 2 Trading Program, then this natural person shall be the same natural person as the alternate designated representative, as defined in the respective program.

Annual capacity factor means the ratio between the actual heat input to an affected EGU during a calendar year and the potential heat input to the affected EGU had it been operated for 8,760 hours during a calendar year at the base load rating. Also see capacity factor.

Authorized account representative means, for a general account, the natural person who is authorized, in accordance with this subpart, to transfer and otherwise dispose of CO_2 allowances held in the general account and, for a CO_2 Mass-based Trading facility's compliance account, the designated representative of the facility is the authorized account representative.

Automated data acquisition and handling system (DAHS) means the component of the continuous emission monitoring system, or other emissions monitoring system approved for use under this subpart, designed to interpret and convert individual output signals from pollutant concentration monitors, flow monitors, diluent gas monitors, and other component parts of the monitoring system to produce a continuous record of the measured parameters in the measurement units required by this subpart.

Base load rating means the maximum amount of heat input (fuel) that an EGU can combust on a steady state basis, as determined by the physical design and characteristics of the EGU at ISO conditions. For a stationary combustion turbine, base load rating includes the heat input from duct burners.

Baseline means the electricity use that would have occurred without implementation of a specific EE measure.

Biomass means biologically based material that is living or dead (*e.g.,* trees, crops, grasses, tree litter, roots) above and below ground, and available on a renewable or recurring basis. Materials that are biologically based include non-fossilized, biodegradable organic material originating from modern or contemporarily grown plants, animals, or microorganisms (including plants, products, byproducts and residues from agriculture, forestry, and related activities and industries, as well as the non-fossilized and biodegradable organic fractions of industrial and municipal wastes, including gases and liquids recovered from the decomposition of non-fossilized and biodegradable organic material).

Boiler means an enclosed fossil- or other-fuel-fired combustion device used to produce heat and to transfer heat to recirculating water, steam, or other medium.

Business day means a day that does not fall on a weekend or a federal holiday.

Capacity factor means, as used for the output based set-aside, the ratio of the net electrical energy produced by a generating unit for the period of time considered to the electrical energy that could have been produced at continuous net summer capacity during the same period.

Certifying official means a natural person who is:

(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;

(2) For a partnership or sole proprietorship, a general partner or the proprietor respectively; or

(3) For a local government entity or state, federal, or other public agency, a principal executive officer or ranking elected official.

Clean Air Act means the Clean Air Act, 42 U.S.C. 7401, *et seq.*

CO_2 allowance means a limited authorization issued and allocated by the Administrator under this subpart, or by a State or permitting authority under a state allowance-distribution methodology approved by the Administrator under § 60.24(x) of this chapter, to emit one ton of CO_2 during a compliance period of the specified calendar year for which the authorization is allocated or of any calendar year thereafter under the CO_2 Mass-Based Trading Program.

CO_2 allowance deduction or deduct CO_2 allowances means the permanent withdrawal of CO_2 allowances by the Administrator from a compliance account (*e.g.,* in order to account for compliance with the CO_2 emission standard).

CO_2 allowances held or hold CO_2 allowances means the CO_2 allowances treated as included in an Allowance Tracking and Compliance System (ATCS) account as of a specified point in time because at that time they:

(1) Have been recorded by the Administrator in the account or transferred into the account by a correctly submitted, but not yet recorded, CO_2 allowance transfer in accordance with this subpart; and

(2) Have not been transferred out of the account by a correctly submitted, but not yet recorded, CO_2 allowance transfer in accordance with this subpart.

CO_2 emission goal means a statewide rate-based CO_2 emission goal or mass-based CO_2 emission goal specified in § 62.16235.

CO_2 emissions limitation means the tonnage of CO_2 emissions authorized in a compliance period in a given year by the CO_2 allowances available for deduction for the facility under § 62.16340(a) for such compliance period.

CO_2 Mass-Based Trading Program means a multi-state CO_2 air pollution control and emission reduction program established in accordance with this subpart and subpart UUUU of part 60 of this chapter (including such a program that is revised in a State plan or state allowance distribution methodology, or by the Administrator under subpart UUUU of part 60 of this chapter), as a means of controlling CO_2 emissions.

Coal means the definition as defined in subpart TTTT of part 60 of this chapter.

Combined cycle unit means an electric generating unit that uses a stationary combustion turbine from which the heat from the turbine exhaust gases is recovered by a heat recovery steam generating unit to generate additional electricity.

Combined heat and power unit or CHP unit, (also known as *''cogeneration''*) means an electric generating unit that uses a steam-generating unit or stationary combustion turbine to simultaneously produce both electric (or mechanical) and useful thermal output from the same primary energy facility.

Common practice baseline (CPB) means a baseline derived based on a default technology or condition that would have been in place at the time of implementation of an EE measure in the absence of the EE measure (for example, the standard or market-average or pre-existing equipment that a typical consumer/building owner would have continued to use or would have installed at the time of project implementation in a given circumstance, such as a given building type, EE program type or delivery mechanism, and geographic region).

Common stack means a single flue through which emissions from two or more units are exhausted.

Compliance account means an ATCS account, established by the Administrator for a CO_2 annual facility under this subpart, in which any CO_2 allowance allocations to the affected EGUs at the facility are recorded and in which are held any CO_2 allowances available for use for a compliance period in a given year in complying with the facility's CO_2 emission standard in accordance with §§ 62.16220 and 62.16340.

Compliance period means the multi-year periods starting January 1 of the first calendar year of the period, except as provided in § 62.16220(c)(3), and ending on December 31 of the last calendar year, inclusive:

(1) Compliance Period 1 means the period of 3 calendar years from January 1, 2022 to December 31, 2024.

(2) Compliance Period 2 means the period of 3 calendar years from January 1, 2025 to December 31, 2027.

(3) Compliance Period 3 means the period of 2 calendar years from January 1, 2028 to December 31, 2029.

Conservation voltage regulation (or reduction) (CVR) means an EE measure that produces electricity savings by reducing (or regulating) voltage at the electrical feeder level.

Continuous emission monitoring system (*CEMS)* means the equipment required under this subpart to sample, analyze, measure, and provide, by means of readings recorded at least once every 15 minutes and using an automated data acquisition and handling system (DAHS), a permanent record of CO_2 emissions, stack gas volumetric flow rate, stack gas moisture content, and O_2 concentration (as applicable), in a manner consistent with part 75 of this chapter and § 62.16345. The following systems are the principal types of continuous emission monitoring systems:

(1) A flow monitoring system, consisting of a stack flow rate monitor and an automated data acquisition and handling system and providing a permanent, continuous record of stack gas volumetric flow;

(2) A moisture monitoring system, as defined in § 75.11(b)(2) of this chapter and providing a permanent, continuous record of the stack gas moisture content, in percent H_2O;

(3) A CO_2 monitoring system, consisting of a CO_2 pollutant concentration monitor (or an O_2 monitor plus suitable mathematical equations from which the CO_2 concentration is derived) and an automated data acquisition and handling system and providing a permanent, continuous record of CO_2 emissions, in percent CO_2; and

(4) An O_2 monitoring system, consisting of an O_2 concentration monitor and an automated data acquisition and handling system and providing a permanent, continuous record of O_2, in percent O_2.

Control area operator means an electric system or systems, bounded by interconnection metering and telemetry, capable of controlling generation to maintain its interchange schedule with other control areas and contributing to frequency regulation of the interconnection.

Deemed savings means estimates of average annual electricity savings for a single unit of an installed demand-side EE measure that: Has been developed from data sources (such as prior metering studies) and analytical methods widely considered acceptable for the measure; and is applicable to the situation and conditions in which the measure is implemented. Individual parameters or calculation methods also can be deemed, including EUL values. Common sources of deemed savings values are previous evaluations and studies that involved actual measurements and analyses. Deemed savings values are applicable for specific demand-side EE measures. A single deemed savings value may not be used for a program as a whole, nor for a multi-measure project, because of the degree of variation in how systems are used in different building types or market segments.

Demand-side energy efficiency or demand-side EE means energy efficiency activities, projects, programs or measures resulting in electricity savings.

Derate means a decrease in the available capacity of an electric generating unit, due to a system or equipment modification or to discounting a portion of a generating unit's capacity for planning purposes.

Designated representative means, for a CO_2 Mass-based Trading facility and each affected EGU at the facility, the natural person who is authorized by the owners and operators of the facility and all such affected EGUs at the facility, in accordance with this subpart, to represent and legally bind each owner and operator in matters pertaining to the CO_2 Mass-based Trading Program. If the CO_2 Mass-based Trading facility is also subject to the Acid Rain Program, TR NO_X Annual Trading Program, TR NO_X Ozone Season Trading Program, TR SO_2 Group 1 Trading Program, or TR SO_2 Group 2 Trading Program, then this natural person shall be the same natural person as the designated representative, as defined in the respective program.

Design efficiency means the rated overall net efficiency (*e.g.,* electric plus thermal output) on a higher heating value basis of the EGU at the base load rating and ISO conditions.

Distillate oil means the definition as defined in subpart TTTT of part 60 of this chapter.

Effective useful life (EUL) means the duration over which electricity savings from an EE measure occur, reported in years. EUL values are typically specific to individual EE projects but also may be specified by EE program.

Energy efficiency measure or EE measure means a single technology, energy-use practice or behavior that, once implemented or adopted, reduces electricity use of a particular end-use, facility, or premises; EE measures may be implemented as part of an EE program or as an independent privately-funded action.

Energy efficiency program or *EE program* means organized activities sponsored and funded by a particular entity to promote the adoption of one or more EE project or EE measure for the purpose of reducing electricity use.

Energy efficiency project or EE project means a combination of multiple technologies, energy-use practices or behaviors implemented at a single facility or premises for the purpose of reducing electricity use; EE projects may be implemented as part of an EE program or as an independent privately-funded action.

Electricity savings means the savings that results from a change in electricity use resulting from the implementation of an EE measure.

Eligible resource means a resource that meets the requirements of § 62.16245 and has been registered with the EPA-administered ATCS or an allowance tracking system approved in a State plan by the EPA. An eligible resource is not an affected EGU.

EM&V plan means an evaluation measurement and verification plan that meets the requirements of § 62.16260.

Emissions means air pollutants exhausted from an affected EGU or facility into the atmosphere; emissions must be measured, recorded, and reported to the Administrator by the designated representative, and as modified by the Administrator:

(1) In accordance with this subpart; and

(2) With regard to a period before the affected EGU or facility is required to measure, record, and report such air pollutants in accordance with this subpart, and in accordance with part 75 of this chapter.

Emission rate credit (ERC) means a tradable compliance instrument that meets the requirements of § 60.5790(c) of this chapter.

Energy service company means a private enterprise engaged in delivering electricity savings directly for an end-use customer or as an agent of a sponsoring entity such as a utility.

Essential generating characteristics means any characteristic that affects the eligibility of the qualifying energy generating facility for generating allowances pursuant to this regulation, including the type of facility.

Excess emissions means any ton of emissions from the affected EGUs at a facility during a compliance period that exceeds the CO_2 emissions limitation for the facility for such compliance period.

Existing state program, requirement, or measure means, in the context of a State plan, a regulation, requirement, program, or measure administered by a state, utility, or other entity that is currently established. This may include a regulation or other legal requirement that includes past, current, and future obligations, or current programs and measures that are in place and are anticipated to be continued or expanded in the future, in accordance with established plans. An existing state program, requirement, or measure may have past, current, and future impacts on EGU CO_2 emissions.

Facility means all buildings, structures, or installations located in one or more contiguous or adjacent properties under common control of the same person or persons. This definition does not change or otherwise affect the definition of ''major source'', ''stationary source'', or ''source'' as set forth and implemented in a title V operating permit program or any other program under the Clean Air Act.

Final compliance period means a compliance period within the final period, each being 2 calendar years (with a calendar year beginning on January 1 and ending on December 31), and the first final compliance period beginning on January 1, 2030 and ending December 31, 2031.

Final period means the period that begins on January 1, 2030 and continues thereafter. The final period is comprised of final compliance periods, each of which is 2 calendar years (with a calendar year beginning on January 1 and ending on December 31).

Fossil fuel means the definition as defined in subpart TTTT of part 60 of this chapter.

Fossil-fuel-fired means, with regard to an affected EGU, combusting any amount of fossil fuel.

Gaseous fuel means the definition as defined in subpart TTTT of part 60 of this chapter.

General account means an ATCS account established under this subpart that is not a compliance account.

Generation period means the compliance period from which the Administrator uses operations data of affected EGUs to calculate allowances from the output-based allocation set-aside for the following compliance period.

Generation year means a calendar year for which a renewable energy project submits its projected generation to the Administrator by June 1 of the preceding year for allowances from the renewable energy set-aside.

Generator means a device that produces electricity.

Gross electrical output means, for an affected EGU, electricity made available for use, including any such electricity used in the power production process (which process includes, but is not limited to, any on-site processing or treatment of fuel combusted at the affected EGU and any on-site emission controls).

Heat input means, for an affected EGU for a specified period of time, the product (in mmBtu/time) of the gross calorific value of the fuel (in mmBtu/lb) fed into the affected EGU multiplied by the fuel feed rate (in lb of fuel/time), as measured, recorded, and reported to the Administrator by the designated representative and as modified by the Administrator in accordance with this subpart and excluding the heat derived from preheated combustion air, recirculated flue gases, or exhaust.

Heat input rate means, for an affected EGU, the amount of heat input (in mmBtu) divided by affected EGU operating time (in hr) or, for an affected EGU and a specific fuel, the amount of heat input attributed to the fuel (in mmBtu) divided by the affected EGU operating time (in hr) during which the affected EGU combusts the fuel.

Heat rate means, for an affected EGU, the affected EGU's maximum design heat input (in Btu/hr), divided by the product of 1,000,000 Btu/mmBtu and the affected EGU's maximum hourly load.

Heat recovery steam generating unit (HRSG) means a unit in which hot exhaust gases from the combustion turbine engine are routed in order to extract heat from the gases and generate useful output. Heat recovery steam generating units can be used with or without duct burners.

Indian country means ''Indian country'' as defined in 18 U.S.C. 1151.

Integrated gasification combined cycle facility or *IGCC facility* means a combined cycle facility that is designed to burn fuels containing 50 percent (by heat input) or more solid-derived fuel not meeting the definition of natural gas plus any integrated equipment that provides electricity or useful thermal output to either the affected facility or auxiliary equipment. The Administrator may waive the 50 percent solid-derived fuel requirement during periods of the gasification system construction, startup and commissioning, shutdown, or repair. No solid fuel is directly burned in the unit during operation.

Interim period means the period of 8 calendar years from January 1, 2022 to December 31, 2029. The interim period is comprised of three compliance periods, compliance period 1, compliance period 2, and compliance period 3.

ISO conditions means 288 Kelvin (15° C), 60 percent relative humidity and 101.3 kilopascals pressure.

Liquid fuel means the definition as defined in subpart TTTT of part 60 of this chapter.

M&V report means a monitoring and verification report that meets the requirements of § 62.16265.

Maximum design heat input means, for an affected EGU, the maximum amount of fuel per hour (in Btu/hr) that the affected EGU is capable of combusting on a steady state basis as of the initial installation of the affected EGU as specified by the manufacturer of the affected EGU.

Mechanical output means the useful mechanical energy that is not used to operate the affected facility, generate electricity and/or thermal output, or to enhance the performance of the affected facility. Mechanical energy measured in horsepower hour should be converted into MWh by multiplying it by 745.7 then dividing by 1,000,000.

Monitoring system means any monitoring system that meets the requirements of this subpart, including a continuous emission monitoring system, an alternative monitoring system, or an excepted monitoring system under part 75 of this chapter.

Nameplate capacity means, starting from the initial installation of a generator, the maximum electrical generating output (in MWe, rounded to the nearest tenth) that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings) of such installation as specified by the manufacturer of the generator or, starting from the completion of any subsequent physical change in the generator resulting in an increase in the maximum electrical generating output that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings), such increased maximum amount (in MWe, rounded to the nearest tenth) of such completion as specified by the person conducting the physical change.

Natural gas means the definition as defined in subpart TTTT of part 60 of this chapter.

Net-electric output means the amount of gross generation the generator(s) produce (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)), as measured at the generator terminals, less the electricity used to operate the plant (*i.e.,* auxiliary loads); such uses include fuel handling equipment, pumps, fans, pollution control equipment, other electricity needs, and transformer losses as measured at the transmission side of the step up transformer (*e.g.,* the point of sale).

Net energy output means:

(1) The net electric or mechanical output from the affected facility, plus 100 percent of the useful thermal output measured relative to SATP conditions that is not used to generate additional electric or mechanical output or to enhance the performance of the affected EGU (*e.g.,* steam delivered to an industrial process for a heating application); and

(2) For combined heat and power facilities where at least 20.0 percent of the total gross or net energy output consists of electric or direct mechanical output and at least 20.0 percent of the total gross or net energy output consists of useful thermal output on a 12-operating month rolling average basis, the net electric or mechanical output from the affected EGU divided by 0.95, plus 100 percent of the useful thermal output (*e.g.,* steam delivered to an industrial process for a heating application).

Net summer capacity means the maximum output, commonly expressed in megawatts (MW), that generating equipment can supply to system load, as demonstrated by a multi-hour test, at the time of summer peak demand (period of June 1 through September 30.) This output reflects a reduction in capacity due to electricity use for station service or auxiliaries.

Operate or *operation* means, with regard to an affected EGU, to combust fuel.

Operator means, for a CO_2 Mass-based Trading facility or an affected EGU at a facility respectively, any person who operates, controls, or supervises an affected EGU at the facility or the affected EGU and includes, but is not limited to, any holding company, utility system, or plant manager of such facility or affected EGU.

Owner means, for a CO_2 Mass-based Trading facility or an affected EGU at a facility respectively, any of the following persons:

(1) Any holder of any portion of the legal or equitable title in an affected EGU at the facility or the affected EGU;

(2) Any holder of a leasehold interest in an affected EGU at the facility or the affected EGU, provided that, unless expressly provided for in a leasehold agreement, ''owner'' does not include a passive lessor, or a person who has an equitable interest through such lessor, whose rental payments are not based (either directly or indirectly) on the revenues or income from such affected EGU; and

(3) Any purchaser of power from an affected EGU at the facility or the affected EGU under a life-of-the-unit, firm power contractual arrangement.

Permanently retired means, with regard to an affected EGU, that an affected EGU is unavailable for service and the affected EGU's owners and operators: have taken on as enforceable obligations in the operating permit that covers the affected EGU the conditions of § 62.16215; or rescinded or otherwise terminated all permits required for construction or operation of the affected EGU under the Clean Air Act. Cessations in operations that do not meet this definition do not constitute permanent retirements.

Qualified biomass means a biomass feedstock that is demonstrated as a method to control increases of CO_2 levels in the atmosphere.

Random error means errors occurring by chance that may cause electricity savings values to be inconsistently overestimated or underestimated, and may result from a change in electricity use due to unaccounted-for factors that affect electricity use. The magnitude of random error can be quantified based on the variations observed across different units.

Receive or *receipt of* means, when referring to the Administrator, to come into possession of a document, information, or correspondence (whether sent in hard copy or by authorized electronic transmission), as indicated in an official log, or by a notation made on the document, information, or correspondence, by the Administrator in the regular course of business.

Recordation, record, or *recorded* means, with regard to CO_2 allowances, the moving of CO_2 allowances by the Administrator into, out of, or between ATCS accounts, for purposes of allocation, transfer, or deduction.

Reference method means any direct test method of sampling and analyzing for an air pollutant as specified in § 75.22 of this chapter.

Replacement, replace, or *replaced* means, with regard to an affected EGU, the demolishing of an affected EGU, or the permanent retirement and permanent disabling of an affected EGU, and the construction of another affected EGU (the replacement affected EGU) to be used instead of the demolished or retired affected EGU (the replaced affected EGU).

Solid fuel means any fuel that has a definite shape and volume, has no tendency to flow or disperse under moderate stress, and is not liquid or gaseous at ISO conditions. This includes, but is not limited to, coal, biomass, and pulverized solid fuels.

Solid waste incineration unit means a stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine that is a ''solid waste incineration unit'' as defined in section 129(g)(1) of the Clean Air Act.

Standard ambient temperature and pressure (SATP) conditions means 298.15 Kelvin (25° C, 77 °F)) and 100.0 kilopascals (14.504 psi, 0.987 atm) pressure. The enthalpy of water at SATP conditions is 50 Btu/lb.

State agent means an entity acting on behalf of the State, with the legal authority of the State.

State measures means measures that the State adopts and implements as a matter of state law. Such measures are enforceable only per state law, and are not included in and codified as part of the federally enforceable State plan.

Stationary combustion turbine means all equipment, including but not limited to the turbine engine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), heat recovery system, fuel compressor, heater, and/or pump, post-combustion emissions control technology, and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any combined cycle combustion turbine, and any combined heat and power combustion turbine based system plus any integrated equipment that provides electricity or useful thermal output to the combustion turbine engine, heat recovery system or auxiliary equipment. Stationary means that the combustion turbine is not self-propelled or intended to be propelled while performing its function. It may, however, be mounted on a vehicle for portability. If a stationary combustion turbine burns any solid fuel directly then it is considered a steam generating unit.

Steam generating unit means any furnace, boiler, or other device used for combusting fuel and producing steam (nuclear steam generators are not included) plus any integrated equipment that provides electricity or useful thermal output to the affected facility or auxiliary equipment.

Submit or *serve* means to send or transmit a document, information, or correspondence to the person specified in accordance with the applicable regulation:

(1) In person;

(2) By United States Postal Service; or

(3) By other means of dispatch or transmission and delivery;

(4) Provided that compliance with any ''submission'' or ''service'' deadline shall be determined by the date of dispatch, transmission, or mailing and not the date of receipt.

Systematic error means inaccuracies in the same direction, causing electricity savings values to be consistently either overestimated or underestimated, and may result from factors such as incorrect assumptions, a methodological issue, or a flawed reporting system.

Transmission and distribution loss means the difference between the quantity of electricity that serves a load (measured at the busbar of the generator) and the actual electricity use at the final distribution location (measured at the on-site meter).

Transmission and distribution measures or T&D measures means EE measures intended to improve the efficiency of the electrical transmission and distribution system by decreasing electricity loses on the system.

Unit operating day means, with regard to an affected EGU, a calendar day in which the affected EGU combusts any fuel.

Unit operating hour or *hour of unit operation* means, with regard to an affected EGU, an hour in which the affected EGU combusts any fuel.

Uprate means an increase in available electric generating unit power capacity due to a system or equipment modification.

Useful thermal output means the thermal energy made available for use in any heating application (*e.g.,* steam delivered to an industrial process for a heating application, including thermal cooling applications) that is not used for electric generation, mechanical output at the affected EGU, to directly enhance the performance of the affected EGU (*e.g.,* economizer output is not useful thermal output, but thermal energy used to reduce fuel moisture is considered useful thermal output), or to supply energy to a pollution control device at the affected EGU. Useful thermal output for affected EGU(s) with no condensate return (or other thermal energy input to the affected EGU(s)) or where measuring the energy in the condensate (or other thermal energy input to the affected EGU(s)) would not meaningfully impact the emission rate calculation is measured against the energy in the thermal output at SATP conditions. Affected EGU(s) with meaningful energy in the condensate return (or other thermal energy input to the affected EGU) must measure the energy in the condensate and subtract that energy relative to SATP conditions from the measured thermal output.

Utility power distribution system means the portion of an electricity grid owned or operated by a utility and dedicated to delivering electricity to customers.

Valid data means quality-assured data generated by continuous monitoring systems that are installed, operated, and maintained according to part 75 of this chapter. For CEMS, the initial certification requirements in § 75.20 of this chapter and appendix A to part 75 of this chapter must be met before quality-assured data are reported under this subpart; for on-going quality assurance, the daily, quarterly, and semiannual/annual test requirements in sections 2.1, 2.2, and 2.3 of appendix B to part 75 of this chapter must be met and the data validation criteria in sections 2.1.5, 2.2.3, and 2.3.2 of appendix B to part 75 of this chapter apply. For fuel flow meters, the initial certification requirements in section 2.1.5 of appendix D to part 75 of this chapter must be met before quality-assured data are reported under this subpart (except for qualifying commercial billing meters under section 2.1.4.2 of appendix D), and for on-going quality assurance, the provisions in section 2.1.6 of appendix D to part 75 of this chapter apply (except for qualifying commercial billing meters).

Verification report means a report that meets the requirements of § 62.16270.

Waste-to-Energy means a process or unit (*e.g.,* solid waste incineration unit) that recovers energy from the conversion or combustion of waste stream materials, such as municipal solid waste, to generate electricity and/or heat.

§ 62.16380 What measurements, abbreviations, and acronyms apply to this subpart?

The measurements, abbreviations, and acronyms used in this subpart are defined as follows:

ADR—alternated designated representative
Btu—British thermal unit
CO_2—carbon dioxide
COI—conflict of interest
CPP—clean power plan
CVR—conservation voltage regulation
DR—designated representative
EE—energy efficiency
EGU—electric generating unit
EM&V—evaluation, measurement, and verification
GCV—gross calorific value
GJ—giga joule
H_2O—water
hr—hour
IGCC—integrated gasification combined cycle
kg—kilogram
kW—kilowatt electrical
kWh—kilowatt hour
lb—pound
M&V—measurement and verification
mmBtu—million Btu
MWe—megawatt electrical
MWh—megawatt hour
O_2—oxygen
PB–MV—project-based measurement and verification
PSD—prevention of significant deterioration
T&D—transmission and distribution
TRM—technical reference manual
yr—year

■ 5. Add subpart NNN to read as follows:

Subpart NNN—Greenhouse Gas Emissions Rate-based Model Trading Rule for Electric Utility Generating Units That Commenced Construction on or Before January 8, 2014

Sec.

Subpart NNN—Greenhouse Gas Emissions Rate-Based Model Trading Rule for Electric Utility Generating Units That Commenced Construction on or Before January 8, 2014

Introduction

§ 62.16405 What is the purpose of this subpart?

(a) This subpart sets forth the requirements for the Clean Power Plan (CPP) CO_2 Rate-based Trading Program, under section 111 of the Clean Air Act and subpart UUUU of part 60 of this chapter, as a means of meeting emission guidelines limiting greenhouse gas emissions from an affected steam generating unit, integrated gasification combined cycle (IGCC), or stationary combustion turbine.

(b) The pollutants regulated by this subpart are greenhouse gases. The greenhouse gas limitations in this subpart are in the form of an emission standard for carbon dioxide (CO_2).

(c) *PSD and Title V thresholds for greenhouse gases.* (1) For the purposes of § 51.166(b)(49)(ii) of this chapter, with respect to GHG emissions from affected facilities, the ''pollutant that is subject to the standard promulgated under section 111 of the Act'' shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in § 51.166(b)(48) of this chapter and in any state implementation plan approved by the EPA that is interpreted to incorporate, or specifically incorporates, § 51.166(b)(48) of this chapter.

(2) For the purposes of § 52.21(b)(50)(ii) of this chapter, with respect to GHG emissions from affected facilities, the ''pollutant that is subject to the standard promulgated under section 111 of the Act'' shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in § 52.21(b)(49) of this chapter.

(3) For the purposes of § 70.2 of this chapter, with respect to greenhouse gas emissions from affected facilities, the ''pollutant that is subject to any standard promulgated under section 111 of the Act'' shall be considered to be the pollutant that otherwise is ''subject to regulation'' as defined in § 70.2 of this chapter.

(4) For the purposes of § 71.2 of this chapter, with respect to greenhouse gas emissions from affected facilities, the ''pollutant that is subject to any standard promulgated under section 111 of the Act'' shall be considered to be the pollutant that otherwise is ''subject to regulation'' as defined in § 71.2 of this chapter.

Applicability of This Subpart

§ 62.16410 Am I subject to this subpart?

(a) You are subject to this subpart if you are the owner or operator of an affected electric generating unit (EGU) located within a State that has incorporated by reference this subpart as a State plan, or portion of a State plan, that has been approved by the Administrator and is effective under subpart UUUU of part 60 of this chapter, or if this subpart is promulgated and effective as a federal plan in your State under part 62 of this chapter.

(b) An affected EGU is any steam generating unit, IGCC, or stationary combustion turbine that meets the applicability requirements in §§ 60.5840(b) and 60.5845 of this chapter.

§ 62.16415 What are the requirements for retired affected EGUs?

(a) *Exemption.* (1) Any affected EGU that is permanently retired as defined in § 62.16570 is exempt from §§ 62.16420(c)(1) [CO_2 Emissions Requirements], 62.16535 [Compliance Requirements], 62.16540 [Monitoring], 62.16555 [Reporting], and 62.16560 [Recordkeeping].

(2) The exemption under paragraph (a)(1) of this section will become effective on the first day of the compliance period immediately following the compliance period in which the retirement took effect. Within 30 days of the affected EGU's permanent retirement, the designated representative must submit a statement to the Administrator. The statement must state, in a format prescribed by the Administrator, that the affected EGU was permanently retired on a specified date and will comply with the requirements of paragraph (b) of this section.

(b) *Special provisions.* (1) An affected EGU exempt under paragraph (a) of this section must not emit any CO_2, starting on the date that the exemption takes effect.

(2) For a period of 5 years from the date the records are created, the owners and operators of an affected EGU exempt under paragraph (a) of this section must retain, at the affected EGU, records demonstrating that the affected EGU is permanently retired. The 5-year period for keeping records may be extended for cause, at any time before the end of the period, in writing by the Administrator. The owners and operators bear the burden of proof that the affected EGU is permanently retired.

(3) The owners and operators and, to the extent applicable, the designated representative of an affected EGU exempt under paragraph (a) of this section must comply with the requirements of the CO_2 Rate-based Trading Program accruing during any compliance periods for which the exemption is not in effect, even if such requirements must be complied with after the exemption takes effect.

General Requirements

§ 62.16420 What emission standards and requirements must I comply with?

(a) *Designated representative requirements.* The owners and operators must have a designated representative, and may have an alternate designated representative, in accordance with §§ 62.16485 through 62.16495.

(b) *Emissions monitoring, reporting, and recordkeeping requirements.* (1) The owners and operators, and the designated representative, of affected EGU must comply with the monitoring, reporting, and recordkeeping requirements of §§ 62.16540, 62.16555, and 62.16560.

(2) The emissions data determined in accordance with § 62.16540 must be used to determine compliance with the CO_2 emission standard under paragraph (c) of this section, provided that, for each monitoring location from which emissions are reported, the emission rate used in determining compliance must be the CO_2 emission rate at the monitoring location determined in accordance with paragraph (c) of this section.

(c) *CO_2 emission standard requirements.* (1) Each designated representative for each affected EGU must demonstrate compliance with its emission standard listed in Table 1 of this subpart, as applicable, by calculating a CO_2 emission rate by factoring stack emissions and any emission rate credits (ERCs) into the following equation:

$$CO_2 \text{emission rate} = \frac{\sum M_{CO2}}{\sum MWh_{op} + \sum MWh_{ERC}}$$

Where:

CO_2 emission rate = An affected EGU's calculated CO_2 emission rate that will be used to determine compliance with the applicable CO_2 emission standard.

M_{CO2} = Measured CO_2 mass in units of pounds (lbs) summed over the compliance period for an affected EGU.

MWh_{op} = Total net energy output over the compliance period for an affected EGU in units of MWh.

MWh_{ERC} = ERC replacement generation for an affected EGU in units of MWh (ERCs are denominated in whole integers as specified in paragraph (c)(2) of this section).

(2) An ERC qualifies for the compliance demonstration specified in paragraph (c)(1) of this section if it:

(i) Has a unique serial number;

(ii) Represents one whole MWh of actual energy generated or saved with zero associated carbon dioxide emissions;

(iii) Was issued to an eligible resource that meets the requirements of § 62.16435 or to an affected EGU that meets the requirements of § 62.16434, by the Administrator through an ERC tracking system or the ATCS; and

(iv) Was surrendered and retired only once for purposes of compliance with this regulation by the Administrator through an ERC tracking system or the ATCS.

(3) An ERC does not qualify for the compliance demonstration specified in paragraph (c)(1) of this section if it does not meet the requirements of paragraph (c)(2) of this section or if any State has used that same ERC for purposes of demonstrating achievement of its state measures.

(4) As of the ERC transfer deadline for a compliance period, the owners and operators of each affected EGU must hold, in the affected EGU's compliance account, sufficient ERCs to demonstrate compliance with its applicable emission standard listed in Table 1 of this subpart pursuant to the requirement of paragraph (c)(1) of this section.

(5) If an affected EGU exceeds its emission standard during a compliance period, then:

(i) The owners and operators of the affected EGU must hold ERCs required for deduction under § 62.16535(e);

(ii) The owners and operators of the affected EGU are subject to federal enforcement pursuant to sections 113(a)–(h), and section 304, of the Clean Air Act, and the United States, States, and other persons have the ability to enforce against violations (including if an affected EGU does not meet its emission standard based on its emissions, or use of ERCs that meet the compliance demonstration in § 62.16420 (c)(2)) and secure appropriate corrective actions, and the owners and operators must pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each day of such compliance period will constitute a separate violation of this subpart and the Clean Air Act;

(iii) If an affected EGU does not meet its emission standard because it did not meet the emissions standard based on its stack emissions and generation alone and it did not obtain sufficient qualifying ERCs to meet its emission standard by July 1 of the year following the relevant compliance period, then it may be subject to federal enforcement pursuant to Sections 113(a)–(h), 42 U.S.C. 7413(a)–(h), and Section 304 of the Clean Air Act, 42 U.S.C. 7604, and the United States, states, and other persons have the ability to enforce violations and secure corrective actions; and

(iv) If an affected EGU obtained sufficient facially valid ERCs to meet its emission standard, but those ERCs were found to be invalid, then it may be subject to federal enforcement as specified in paragraph (c)(5)(iii) of this section.

(d) *Compliance periods.* An affected EGU will be subject to the requirements under paragraph (c)(1) of this section for the compliance period starting on January 1, 2022, and for each compliance period thereafter.

(1) *Vintage of ERCs held for compliance.* An ERC held for compliance with the requirements under paragraph (c)(1) of this section for a compliance period must be an ERC that was issued for a year in such compliance period or for a year in a prior compliance period.

(2) *ATCS.* Each ERC must be held in, deducted from, transferred into, out of, or between ATCS accounts in accordance with this subpart.

(3) *Limited authorization.* (i) An ERC shall only be used in accordance with the CO_2 Rate-based Trading Program; and

(ii) Notwithstanding any other provision of this subpart, the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.

(4) *Property right.* An ERC does not constitute a property right.

(e) *Title V permit requirements.* (1) Unless otherwise specified in this paragraph, all requirements of this subpart shall be applicable requirements that must be included in an affected EGU's title V permit.

(2) The applicable requirements of this subpart, as well as other terms or conditions necessary to ensure compliance with the applicable requirements, may be added to, or changed in, a title V permit using minor permit modification procedures in accordance with §§ 70.7(e)(2) and 71.7(e)(1) of this chapter, provided that such changes do not conflict with any existing terms of the permit. This paragraph explicitly provides that the addition of, or change to, an affected EGU's description as described in the prior sentence is eligible for minor permit modification procedures in accordance with §§ 70.7(e)(2)(i)(B) and 71.7(e)(1)(i)(B) of this chapter.

(3) No title V permit revision will be required for any crediting, holding, deduction, or transfer of ERCs in accordance with this subpart, provided that the requirements applicable to such creditings, holdings, deductions, or transfers of ERCs are already incorporated in such permit.

(f) *Liability.* Any provision of the CO_2 Rate-based Trading Program that applies to an affected EGU or the designated representative of an affected EGU shall also apply to the owners and operators of such affected EGU.

(g) *Effect on other authorities.* No provision of the CO_2 Rate-based Trading Program or exemption under § 62.16415 shall be construed as exempting or excluding the owners and operators, and the designated representative, of an affected EGU from compliance with any other provision of the applicable, approved state implementation plan, a federally enforceable permit, or any other requirement of the Clean Air Act.

§ 62.16425 How should I compute time under the CO_2 Rate-based Trading Program?

(a) Unless otherwise stated, any time period scheduled, under the CO_2 Rate-Based Trading Program, to begin on the occurrence of an act or event shall begin on the day the act or event occurs.

(b) Unless otherwise stated, any time period scheduled, under the CO_2 Rate-Based Trading Program, to begin before the occurrence of an act or event will be computed so that the period ends the day before the act or event occurs.

(c) Unless otherwise stated, if the final day of any time period, under the CO_2 Rate-Based Trading Program, is not a business day, then the time period will be extended to the next business day.

§ 62.16430 What are the administrative appeal procedures?

The administrative appeal procedures for decisions of the Administrator under the CO_2 Rate-based Trading Program are set forth in part 78 of this chapter.

§ 62.16431 How will the Clean Energy Incentive Program be administered under the federal plan?

(a)(1) The Administrator will participate in the Clean Energy Incentive Program, established under subpart UUUU of part 60 of this chapter, on behalf of any state for whom this subpart is promulgated as a federal plan under section 111(d) of the Act. The Administrator will award, on behalf of each such state, early action ERCs for generation and savings achieved in 2020 and/or 2021 that result from the following types of eligible renewable energy (RE) and demand-side energy efficiency (EE) projects:

(i) Metered wind power;

(ii) Metered solar power; and

(iii) Demand-side EE implemented in a low-income community.

(2) Eligible RE projects must commence construction, and eligible demand-side EE projects must commence implementation, after September 6, 2018 for those states on whose behalf the EPA is implementing the federal plan. Eligible projects must be located in or benefit the state on whose behalf the EPA is implementing the federal plan.

(b) Early action ERCs will be distributed pursuant to a process to be prescribed by the Administrator, and in a manner to be demonstrated by the Administrator to have no impact on the aggregate emission performance of affected EGUs required to meet rate-based emission standards during the compliance periods.

(c) The Administrator will match these early action ERCs with additional matching ERCs pursuant to a process to be prescribed by the Administrator. Matching awards will be made up to a limit equivalent to the state's pro rata share of 300 million short tons of CO_2 emissions.

(d) The awards, including the matching award, will be executed as follows:

(1) For RE projects that generate metered MWh from wind or solar resources: For every two MWh generated, the project will receive one early action ERC under paragraph (b) of this section and one matching ERC from the match under paragraph (c) of this section; and

(2) For EE projects that benefit low-income communities as determined by the Administrator solely for purposes of this subpart: For every two MWh in end-use demand savings achieved, the project will receive two early action ERCs under paragraph (b) of this section and two matching ERCs from the match under paragraph (c) of this section.

Emission Rate Credit Issuance, Adjustment, and Revocation

§ 62.16434 What affected EGUs qualify for generation of ERCs?

(a) ERCs may only be issued to affected EGUs under the conditions listed in paragraphs (b) and (c) of this section.

(b) For affected EGUs that emit below their applicable emission standard, the amount of ERCs generated must be calculated using the following equation:

$$\text{ERCs} = \frac{(\text{EGU emission standard} - \text{EGU emission rate})}{\text{EGU emission standard}} * \text{EGU generation}$$

Where:

ERCs = Number of emission rate credits generated by an affected EGU during an applicable compliance period (MWh).

EGU emission standard = The emission standard the affected EGU must comply with during the applicable compliance period according to § 62.16420 (lb/MWh).

EGU emission rate = The affected EGU's measured CO_2 emission rate measured in accordance with § 62.16540 (lb/MWh).

EGU generation = Total net energy output generation of the affected EGU during the applicable compliance period measured in accordance with § 62.16540 (MWh).

(c) Stationary combustion turbines that meet the definition of an affected EGU may generate net energy output MWh gas shift ERCs (GS–ERCs) for all hours of operation during a given compliance period according to paragraphs (c)(1) through (3) of this section.

(1) To calculate the number of GS–ERCs:

GS–ERCs = EGU Generation * Incremental Generation Factor * GS–ERC Emission Factor

Where:

GS–ERC = Net energy output MWh gas shift ERCs.

EGU generation = Total net energy output generation of the affected EGU during the applicable compliance period measured in accordance with § 62.16540 (MWh).

Incremental Generation Factor = See Table 2 of this subpart for the applicable factor for each compliance period.

GS–ERC Emission Factor = Value calculated using equation (c)(2) of this section.

(2) To calculate the GS–ERC Emission factor for your specific affected EGU you must use the following equation:

$$\text{GS−ERC Emission Factor} = 1 - \frac{\text{EGU emission rate}}{\text{Steam Turbine Emission Standard}}$$

Where:

GS–ERC Emission Factor = Factor to be used in the equation in paragraph (c)(1) of this section for GS–ERC calculation.

EGU emission rate = Affected EGU's measured CO_2 emission rate measured in accordance with § 62.16540 (lb/MWh).

Steam turbine emission standard = Steam turbine emission standard for the corresponding compliance period as found in Table 1 of this subpart (lb/MWh).

(3) Notwithstanding any other provision of this subpart, GS–ERCs must not be used for compliance by an affected EGU that is a stationary combustion turbine. Stationary combustion turbines may use other ERCs in their compliance demonstration.

§ 62.16435 What eligible resources qualify for generation of ERCs in addition to affected EGUs?

(a) ERCs may only be issued to an eligible resource that meet each of the requirements in paragraphs (a)(1) through (4) of this section. All categories of resources other than on-shore utility scale wind, utility scale solar photovoltaics, concentrated solar power, geothermal power, nuclear energy, or utility scale hydropower, and all provisions of this subpart relating to such resources, are not available or applicable in States where this subpart has been promulgated as a federal plan pursuant to section 111(d)(2) of the Act.

(1) Resources qualifying for eligibility only include resources which increased new installed electrical generation nameplate capacity, or new electrical savings measures installed or implemented after January 1, 2013. If a resource had a nameplate capacity uprate, then ERCs may be issued only for the difference in generation between the uprated nameplate capacity and its nameplate capacity prior to the uprate. ERCs must not be issued for generation for an uprate that followed a derate that occurred on or after January 1, 2013. A resource that is relicensed or receives a license extension is considered existing

capacity and is not an eligible resource, unless it receives a capacity uprate as a result of the relicensing process that is reflected in its relicensed permit. In such a case, only the difference in nameplate capacity between its relicensed permit and its prior permit is eligible to be issued ERCs.

(2) The resource must be connected to, and delivers energy to or saves electricity, on the electric grid in the contiguous United States.

(3) The resource is located in a State whose affected EGUs are subject to rate-based emission standards pursuant to this regulation, unless the resource is located in a State with mass-based emission standards and the resource can demonstrate (*e.g.,* through a power purchase agreement or contract for delivery) transmission of its generation into a State whose affected EGUs are subject to rate-based emission standards pursuant to this regulation.

(4) The resource falls into one of the following categories of resources:

(i) Renewable electric generating technologies using one of the following renewable energy resources: wind, solar, geothermal, hydro, wave, tidal;

(ii) Qualified biomass;

(iii) Waste-to-energy (biogenic portion);

(iv) Nuclear energy;

(v) A non-affected combined heat and power unit, including waste heat power; or

(vi) A demand-side EE or demand-side management measure that saves electricity and is calculated on the basis of quantified ex poste savings, not ''projected'' or ''claimed'' savings.

(b) Any resource that does not meet the requirements of this subpart cannot generate ERCs for use in the compliance demonstration required under § 62.16420.

(c) ERCs may not be issued to any of the following:

(1) New, modified, or reconstructed EGUs that are subject to subpart TTTT of part 60 of this chapter, except CHP units that meet the requirements of a CHP unit under paragraph (a) of this section;

(2) EGUs that do not meet the applicability requirements of § 62.16410, except CHP units that meet the requirements of a CHP unit under paragraph (a) of this section;

(3) Measures that reduce CO_2 emissions outside the electric power sector, including GHG offset projects representing emission reductions that occur in the forestry and agriculture sectors, direct air capture, and crediting of CO_2 emission reductions that occur in the transportation sector as a result of vehicle electrification; and

(4) Any measure not approved by the EPA to generate ERCs in connection with a specific State plan.

§ 62.16440 What is the process for revocation of qualification status of an eligible resource?

(a) If an eligible resource is found to not meet the requirements of § 62.16435 in the Rate-based Trading Program, then the Administrator will revoke the eligibility of the eligible resource to be issued ERCs. In addition, the provisions of § 62.16450(d) may apply.

(b) Any instance of intentional misrepresentation in an eligibility application or monitoring and verification (M&V) report may be cause for revocation of the qualification status of an eligible resource.

(c) Repeated instances of error or misstatement of MWh of electricity generation or savings in submitted M&V reports, or in any other submissions may be cause for the Administrator to revoke the eligibility of an eligible resource to be issued ERCs.

(d) In the event of an intentional misrepresentation, or repeated instances of error or misstatement, in program submissions, by the authorized account representative of the eligible resource, the Administrator may prohibit the eligible resource from any further eligibility to be issued ERCs. In addition, the provisions of § 62.16450 (a) through (d) may apply.

§ 62.16445 What is the process for the issuance of ERCs?

The process and requirements for issuance of ERCs for affected EGUs and eligible resources are set forth in paragraphs (a) through (f) of this section.

(a) *Eligibility application.* To receive ERCs, an authorized account representative of an eligible resource must submit an eligibility application to the Administrator that demonstrates that the requirements of § 62.16434 (for an affected EGU) or § 62.16435 (for an eligible resource) are met, and, in the case of an eligible resource only, demonstrates that the requirements in paragraphs (a)(1) through (9) of this section are met.

(1) Identification of the authorized account representative of the eligible resource, including the authorized account representative's name, address, email address, telephone number, and ERC tracking system account number.

(2) Identification of the eligible resource(s), including the information in paragraphs (a)(2)(i) through (v) of this section.

(i) For an eligible resource, the physical location of the eligible resource; contact information for the owner or operator of the eligible resource, if different from the designated representative or authorized account representative; eligible resource generator prime mover and/or technology type; eligible resource nameplate capacity; eligible resource category (*e.g.,* wholesale generator, wholesale generator also serving onsite customer load, customer-sited distributed generator) (if applicable); facility and generating unit IDs (EIA ORIS Code, Facility Registration System (FRS) Code, if applicable); for the eligible resource, the control area, balancing authority, ISO conditions as defined in § 62.16570, or the regional transmission organization in which the generator is located (if applicable).

(A) For an eligible resource with a nameplate capacity of1 MW or more, a copy of the most recent filing of a copy of the generating facility's U.S. Energy Information Agency's Annual Electric Generator Report Form EIA–860.

(B) For an electric generating resource with a nameplate capacity of less than 1 MW, the information that would be contained in U.S. Energy Information Agency's Annual Electric Generator Report Form EIA–860, if that electric generating facility had nameplate capacity of 1 MW or more.

(ii) For an energy-saving resource that is project-based, a detailed description of the demand-side EE or electricity savings project, including: Location and specifications of the building(s), facility(ies), or installations where energy-saving measures were implemented or will be implemented; owner and operator of the building(s), facility(ies), or installations where the energy-saving measures are implemented or will be implemented; the parties implementing the energy-saving project, including lead contractor(s), subcontractors, and consulting firms (if different from the authorized account representative); energy-saving measures installed and/or energy-savings practices implemented (or to be installed/implemented); specifications of equipment and materials installed, or to be installed, as part of the energy-saving project; project plans and technical schematics, as applicable.

(iii) For an energy-savings resource that involves an EE requirement or program, a description of the electricity savings program, including: Overall approach or ''logic'' to the requirement or program, including applicable strategies and activities, along with key assumptions regarding how such strategies and activities will achieve quantifiable reductions in electricity consumption; location and geographic distribution of the targeted building(s), facility(ies), or installations where energy-saving requirements or programs were implemented or will be implemented; electricity consuming system(s), end-use(s), building or facility type(s), or installations where the energy-saving requirements or programs are implemented or will be implemented; the parties implementing the energy-saving requirement or program, including lead contractor(s), subcontractor(s), and consulting firms (if different from the authorized account representative); specifications of energy-saving equipment and/or energy-savings practices implemented (or to be installed/implemented) under the requirement or program; the delivery mechanisms of the requirement or program, which may include financial incentives or equipment rebates, dissemination of actionable information to electricity customers, on-site audits paired with technical recommendations.

(iv) For other electricity-saving resources (*e.g.,* transmission and distribution (T&D) measures such as conservation voltage reduction (CVR)), a description of the resource, including: Overall approach or ''logic'' to the electricity-saving resource, including applicable strategies and activities, along with key assumptions regarding how such strategies and activities will achieve quantifiable reductions in electricity consumption; location and geographic distribution of the targeted building(s), facility(ies), or electricity transmitting and distributing systems, as applicable, where electricity-saving resources were implemented or will be implemented; electricity consuming, transmitting, or distributing system(s), building or facility type(s), or end-use(s) where the electricity-saving resource are implemented or will be implemented; the parties implementing the electricity-saving resource, including lead contractor(s), subcontractor(s), and consulting firms (if different from the authorized account representative); specifications of installed equipment and/or implemented practices (or to be installed/implemented); the delivery mechanisms used to implement and propagate the electricity-saving resource, as applicable.

(v) For eligible resources with distributed locations, such as measures at multiple residential, commercial, or industrial buildings, at a minimum, aggregated information about the location of measures that constitute an eligible resource, provided that the accredited independent verifier and the Administrator have the ability to access information specifying the location of each discrete measure that constitutes an eligible resource.

(3) Demonstration that the eligible resource meets all applicable eligibility requirements in § 62.1435.

(4) A certification that the eligibility application has only been submitted to the Administrator or pursuant to an EPA-approved multi-state approach where States are providing for joint issuance of ERCs pursuant to the authority in their individual State plans.

(5) An evaluation measurement and verification (EM&V) plan.

(6) A verification report from an accredited independent verifier who meets the requirements of §§ 62.16470 and 62.16475.

(7) An authorization that provides for the following: The Administrator may inspect (including a physical inspection of the eligible resource and its meter) and/or audit the eligible resource at any time and verify that the eligible resource and the EM&V plan have been implemented as described in the eligibility application.

(8) The following statement, signed by the designated representative of the eligible resource:

(i) ''I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my personal knowledge and/or inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.''

(ii) [Reserved]

(9) Any other information required by the Administrator.

(b) *Registration of eligible resources.* The Administrator must review the eligibility application to determine whether the affected EGU or eligible resource meets the requirements of § paragraph (a) of this section, and if it determines that the requirements are met, approve the eligibility application and register the affected EGU or eligible resource in an ERC tracking system that meets the requirements of § 62.16515. Once so registered, the affected EGU or eligible resource is eligible to be issued ERCs, provided all other applicable requirements continue to be met.

(c) *M&V reports.* For an eligible resource, the designated representative must submit to the Administrator an M&V report prior to issuance of ERCs by the Administrator.

(d) *Verification reports.* For an eligible resource, the authorized account representative must submit a verification report from an accredited independent verifier that meets the requirements of §§ 62.16470 and 62.16475 as part of each eligibility application and M&V report. While considered a part of the eligibility application and M&V report, the verification report must be submitted separately by the accredited independent verifier to the Administrator.

(e) *Issuance of ERCs.* ERCs may only be issued by the Administrator based on actual electricity generation or savings documented in an M&V report that meets the requirements of § 62.16460 and a verification report that meets the requirements of § 62.16465. Only one ERC will be issued for each verified MWh.

(f) *Tracking system.* ERCs may only be issued through an ERC tracking system that meets the requirements of § 62.16515.

§ 62.16450 What is the process for error adjustments or misstatement, and suspension of ERC issuance?

(a) In the event of error or misstatement of quantified MWh of electricity generation or savings in a previous M&V report for which ERCs have been issued, the Administrator may adjust the number of ERCs issued in a subsequent reporting period to address the error or misstatement, by subtracting a number of MWh from the quantified and verified MWh in the M&V report for the subsequent reporting period. In the event that an error or inadvertent misstatement occurs in a final M&V report for an eligible resource, for which ERCs have been issued, the provisions of paragraph (b) of this section will apply.

(b) In the event of error or misstatement of quantified MWh of electricity generation or savings in the final M&V report for an eligible resource, for which ERCs have been issued, the Administrator will revoke ERCs from the general account held by the authorized account representative of the eligible resource, in an amount necessary to correct the error or misstatement. In the event that the general account of the eligible resource holds an insufficient number of ERCs to correct the error or misstatement, the authorized account representative must submit to the Administrator within 30 days a number of ERCs necessary to correct the error or misstatement. Failure to meet this requirement will result in prohibition of the authorized account representative for the eligible resource from further participation in the program, unless reauthorized at the discretion of the Administrator.

(c) The Administrator may freeze the general account held by an authorized account representative of an eligible resource at any time, for cause, if the Administrator determines ERCs have been improperly issued, based on a misrepresentation or misstatement in an eligibility application or M&V report. The Administrator may also freeze the general account of an authorized account representative of an eligible resource pending investigation of potential misrepresentation, error, or misstatement in an eligibility application of an eligible resource, or in an M&V report for which ERCs have been issued. Freezing a general account will prevent transfer of ERCs out of the account.

(d) If ERCs are issued for an eligible resource that is found to be ineligible, then the Administrator may take the actions in paragraphs (d)(1) through (3) of this section.

(1) Freeze the general account for the eligible resource, preventing any transfers of ERCs out of the account.

(2) Revoke and deduct ERCs held in the general account of the authorized account representative for an eligible resource, in a number equal to the number of ERCs issued for the ineligible eligible resource.

(3) In the event that the general account of the eligible resource holds a number of ERCs less than the number of ERCs issued for the ineligible eligible resource, the delegated representative of an eligible resource must submit to the Administrator within 30 days a number of ERCs necessary to fully account for all ERCs issued for the ineligible eligible resource. Failure to meet this requirement will result in prohibition of the eligible resource from further participation in the program, unless reauthorized at the discretion of the Administrator.

(e) The Administrator may temporarily or permanently suspend issuance of ERCs for an eligible resource, for the following reasons in paragraphs (e)(1) through (3) of this section.

(1) Pending investigation of potential misrepresentation, error, or misstatement in an M&V report, for which ERCs have been issued, or the eligibility status of an eligible resource.

(2) In the case of repeated error or misstatements in submitted M&V reports.

(3) In the case of an intentional misrepresentation in a submitted M&V report.

Evaluation Measurement and Verification Plans, Monitoring and Verification Reports, and Verification

§ 62.16455 What are the requirements for evaluation measurement and verification plans for eligible resources?

(a) *EM&V plan requirements.* Any EM&V plan submitted in support of the issuance of an ERC pursuant to this rule must meet the requirements of this section.

(b) *General EM&V plan criteria.* Each EM&V plan must identify the eligible resource and its approved eligibility application.

(c) *Specific EM&V plan criteria.* Each EM&V plan must provide the manner in which the electricity generated or saved by the eligible resource will be quantified, monitored and verified, and the manner of quantification, monitoring and verification must meet the criteria listed in paragraphs (c)(1) through (7) of this section, as applicable to the specific eligible resource.

(1) For a nuclear energy resource or a renewable energy resource with a nameplate capacity of 10 kW or more and for a renewable energy resource with a nameplate capacity of less than 10 kW for which metered data are available, each EM&V plan must specify that the requirements in paragraphs (c)(1)(i) through (vi) of this section are met.

(i) The generation data are physically measured on a continuous basis using a revenue-quality meter, which means a meter used by a control area operator for financial settlements, or a meter that meets the American National Standards Institute No. C12.20., Code for Electricity Metering, metering accuracy standards, or a meter that meets an alternative equivalent standard that has been approved in advance of its use to measure generation pursuant to this regulation by the EPA.

(ii) The generating data are measured at the generator's bus bar, or, for a renewable energy resource with a nameplate capacity of less than 10 kW that is interconnected behind an individual business or household meter, the generating data were measured at the AC output of the inverter and adjusted to reflect the only energy delivered into either the transmission or distribution grid at the generator bus bar and not any energy used on-site at the generator.

(iii) The generation data from only one eligible resource generating unit may be associated with each meter, and generation data may not be aggregated, unless all the following provisions are met:

(A) All of the generating units have the same essential generation characteristics;

(B) All of the generating units are located in the same State;

(C) The nameplate capacity of the individual units being aggregated is each less than 150 kW, and units collectively do not exceed a total nameplate capacity of 1 MW when aggregated, or alternative requirements approved by the EPA in connection with the specific State plan pursuant to which that EM&V plan or M&V report is submitted; and

(D) The generation data are measured by the same type of meter that is subject to the same maintenance and quality assurance procedures.

(iv) The generation data are collected electronically and telemetered from the generator to its control area operator and verified through a control area energy accounting or settlement process which occurs at least monthly, unless the generation unit does not go through a control area operator, in which case the generation data must be collected by manual meter readings conducted by an independent verifier that is either not affiliated with the owner or operator of the qualifying renewable energy generating resource or is precluded pursuant to the relevant State plan from the ability to transfer or retire ERCs issued to that qualifying renewable energy generating resource or, if the generating unit is less than 10 kw and does not generate enough electricity to enable monthly reporting, then the data may be self-reported and reported no less than annually.

(v) The generation data serve a load that otherwise would have been served by the grid if not for the generator. Specifically:

(A) ERCs shall not be issued for energy generation used to supply the ancillary equipment used to operate a generating station or substation (''station service'') or parasitic load on the generator's side of the point of interconnection; and

(B) For generators interconnected to transmission systems and with on-site loads other than station service drawing generation before the metering point, ERCs may be issued for on-site load, if the owner or operator of the eligible resource can demonstrate that the metering used is capable of distinguishing between on-site load and station service.

(vi) Any other requirements approved by the EPA in connection with the specific State plan pursuant to which that EM&V plan is submitted.

(2) For a renewable energy resource with a nameplate capacity of less than 10 kW and that does not have a meter, each EM&V plan must require that the following requirements in paragraphs (c)(2)(i) though (vii) of this section are met.

(i) Metered data are unavailable.

(ii) At least 1 MW of net energy output is generated to the distribution or transmission system over a continuous 365-day period.

(iii) The generation data may not be aggregated, unless the following provisions are met:

(A) All of the generating units have the same essential generation characteristics;

(B) All of the generating units are located in the same State;

(C) The nameplate capacity of the individual units being aggregated is each less than 150 kW, and units collectively do not exceed a total nameplate capacity of 1 MW when aggregated, or alternative requirements approved by the EPA in connection with the specific State plan pursuant to which that EM&V plan or M&V report is submitted; and

(D) The generation data are measured by the same generation estimating software or algorithms.

(iv) The generation data are measured on at least a monthly basis using generation estimating software or algorithms that are based on an on-site inspection prior to interconnection and a resource study (wind, shading, solar irradiance, depending on the resource), or engineering information that takes into account the capacity, age, and type of qualifying energy generating resource, and all input parameters and assumptions must be clearly delineated, or if the generating unit does not generate enough electricity to enable monthly reporting, then the data may be reported no less than annually.

(v) The generation data are self-reported to the distribution utility through an electronic internet-based portal with software that reports total and hourly generation.

(vi) The generation data serve a load that otherwise would have been served by the grid if not for the generator. The ERC is only based on generation transferred from the eligible resource to the transmission or distribution grid, and is not based on the generation used on-site by the customer.

(vii) Any other requirements approved by the EPA in connection with the specific State plan pursuant to which that EM&V plan is submitted.

(3) For qualified biomass feedstocks used, in addition to the requirements of paragraphs (c)(1) or (2) of this section, whichever section is applicable, each EM&V plan must demonstrate that the requirements approved by the EPA for that biomass feedstock, and its associated biogenic CO_2, have been met.

(4) For a waste-to-energy resource, in addition to the requirements of paragraphs (c)(1) or (2) of this section, as applicable, and paragraph (c)(3) of this section, each EM&V plan must specify:

(i) The total net energy generation from the resource in MWh;

(ii) The method for determining the specific portion of the total net energy output from the resource that is related to the biogenic portion of the waste materials; and

(iii) The net energy output measured with the relevant method approved by the EPA in connection with the specific State plan pursuant to which that EM&V plan is submitted demonstrates that the requirements approved by the EPA in connection with that State plan have been met.

(5) For a combined heat and power unit, in addition to the requirements of paragraphs (c)(1) or (2) of this section, as applicable, and paragraph (c)(3) of this section, each EM&V plan must meet one of the requirements in paragraphs (c)(5)(i) through (iv) of this section, as applicable, and any other requirements approved by the EPA.

(i) If the combined heat and power unit has an electric generating capacity greater than 25 MW, then the EM&V plan must meet the requirements that apply to an affected EGU under § 62.16540.

(ii) If the combined heat and power unit has an electric generating capacity less than or equal to 25 MW and greater than 1 MW, and it uses only natural gas and/or distillate fuel oil, then the EM&V plan must meet the low mass emission unit CO_2 emission monitoring and reporting methodology in part 75 of this chapter.

(iii) If the combined heat and power unit has an electric generating capacity less than or equal to 25 MW and greater than 1 MW, and it uses anything other than only natural gas and/or distillate fuel oil, then the EM&V plan must meet the low mass emission unit CO_2 emission monitoring and reporting methodology in part 75 of this chapter.

(iv) If the combined heat and power unit has an electric generating capacity less than or equal to 1 MW the unit must keep monthly cumulative recordings of useful thermal output and fossil fuel input along with the determination of baseline thermal source efficiencies based on manufacturer data. For CHP units that directly serve on-site end-use electricity loads, avoided T&D system losses can be assessed as is commonly practiced with demand-side EE.

(6) For demand-side electricity savings that avoid a transmission and distribution loss, each EM&V plan must measure the transmission and distribution loss based on the lesser of 6 percent of the facility- or premises-level electricity savings measured at the electricity customer's meter, or the statewide annual average transmission and distribution loss rate (expressed as a percentage) from the most recent year that is published in the US EIA State Electricity Profile. No other transmission and distribution loss factors may be used in calculating the electricity savings.

(7) Each EM&V plan for an EE program, EE project, or EE measure must specify how each of the requirements in paragraphs (c)(7)(i) through (x) of this section will be met in quantifying the electricity savings from that EE program, EE project, or EE measure.

(i) All electricity savings must be quantified on an ex-post basis, which means after the electricity savings have occurred, or on a real-time basis, which means at the time the electricity savings are occurring. Electricity savings must not be quantified on an ex-ante basis, which means estimates of MWh savings that are generated prior to implementing the subject EE program, EE project, or EE measure, and that are not quantified using EM&V methods and procedures.

(ii) All electricity savings must be quantified and verified based on methods and procedures detailed in an industry best-practice EM&V protocol or guideline. Each EM&V plan must include a demonstration of how the best-practice protocol or guideline was selected and will be applied to the specific EE program, EE project, or EE measure covered in the EM&V plan, and an explanation of why that particular protocol or guideline was selected. Protocols and guidelines are considered to be best practice if they:

(A) Have gone through a rigorous and credible peer review process that shows the applicable methods to be valid through empirical testing; and

(B) Have been accepted and approved for use by identifiable state regulatory commissions. Examples of such protocols and guidelines that may be provided in EM&V guidance issued by the Administrator will be acceptable.

(iii) All electricity savings must be quantified as the difference between the observed electricity use and a common practice baseline (CPB), which is the equipment that would typically have been installed—or that a typical consumer or building owner would have continued using—in a given circumstance (*i.e.,* a given building type, EE program type or delivery mechanism, and geographic region) at the time of EE implementation. Examples of CPBs for specific EE programs, EE projects, EE measures, and for certain EM&V methods that may be provided in EM&V guidance issued by the Administrator will be acceptable. The EM&V plan must specify the reason the specific CPB was selected, which must include an analysis of the appropriateness of that CPB for the EE program, EE project, or EE measure covered in the EM&V plan, based on:

(A) Characteristics of the EE program, EE project, or EE measure;

(B) The delivery mechanism used to implement the EE program, EE project, or EE measure (*e.g.,* installed as part of a utility EE program versus a point-of-sale rebate);

(C) Local consumer and market characteristics;

(D) Applicable building energy codes and standards and average compliance rates; and

(E) The method applied: Project-based measurement and verification (PB–MV), comparison group approaches, or deemed savings.

(iv) All electricity savings must be quantified by applying one or more of the following methods: Project-based measurement and verification (PB–MV), comparison group approaches, or deemed savings.

(A) If a comparison group approach is used, then the EM&V plan must quantify electricity savings by taking the difference between a comparison group's electricity use and the electricity use of EE program participants. Comparison group approaches may include randomized control trials and quasi-experimental methods, as described in industry best-practice protocols and guidelines. Examples of such protocols and guidelines provided in EM&V guidance that may be issued by the Administrator will be acceptable.

(B) If deemed savings are used, then the EM&V plan must specify that the deemed savings values will only be used for the specific EE measure for which they were derived. The EM&V plan must also specify the name and Web address of the technical reference manual (TRM) in which all deemed electricity savings values will be documented. Prior to use in an EM&V plan, all TRMs must undergo a review process in which the public, stakeholders, and experts are invited—with adequate advance notification (via the internet and other social media)—to provide comment, have at least 2 months to provide comment, and in which all such comments and associated responses are made publicly available. All TRMs must also be publicly accessible over the full period of time in which they are being used in conjunction with an EM&V plan for the purpose of quantifying savings, and must be subsequently updated in the same manner at least every 3 years. The TRM must indicate, for each subject EE measure, the associated electricity savings value, the conditions under which the value can be applied (including the climate zone, building type, manner of implementation, applicable end uses, operating conditions, and effective useful life), and the manner in which the electricity savings value was quantified, which must include applicable engineering algorithms, source documentation, specific assumptions, and other relevant data to support the quantification of savings from the subject EE measure.

(v) All EE programs, EE projects, or EE measures must be quantified at time intervals (in years) sufficient to ensure that MWh savings are accurately and reliably quantified. Such time intervals must be specified and explained in the EM&V plan. Factors that must be taken into consideration when determining the appropriate time interval include the characteristics of the specific EE program, EE project, or EE measure, expected variability in electricity savings (where greater variability necessitates more frequent quantification), the expected scale and magnitude of the electricity savings (where greater quantities of savings necessitate more frequent quantification), and the experience implementing and quantifying savings from the resource (where less experience—for example, with new and innovative EE program types—necessitates more frequent quantification). The time intervals must end no sooner than the last day of the effective useful life of the EE program, EE project, or EE measure, and must last no longer than:

(A) Every 4-year intervals for building energy codes and product standards;

(B) Every 1, 2, or 3 years for public or consumer-funded EE program, EE project, or EE measure, as relevant for the type of EE program, EE project, or EE measure and factors listed in paragraph (c)(7)(v) of this section; and

(C) Annually for commercial and industrial projects, unless the resource provider can provide a reasonable justification in the EM&V plan for why an annual time interval is not feasible, and can additionally explain how the accuracy and reliability of savings values will not be lessened.

(vi) EM&V plans must specify and document how the EM&V components in paragraphs (c)(7)(vi)(A) through (E) of this section will be analyzed, considered, or otherwise addressed in the quantification and verification of electricity savings.

(A) The effects of changes in independent factors on reported electricity savings (*i.e.,* factors that are not directly related to the EE measure, such as weather, occupancy, and production levels).

(B) The effective useful life (EUL) or duration of time the EE measure is anticipated to remain in place and operable with the potential to save electricity, which must be based on the application of EM&V methods, an industry best-practice persistence study, deemed estimates of effective useful life, or a combination of all three.

(1) If deemed estimates of effective useful life are used, then they must specify the date by which the EE measure will stop saving electricity.

(2) If industry best-practices persistence studies are used to modify an effective-useful-life value, then they must be conducted at least every 5 years.

(C) The potential sources of double counting, and the associated steps for avoiding and correcting for it, such as:

(1) For an EE program or EE project with identified participants, track the type and number of EE measures implemented at the utility-customer level.

(2) For an EE program or EE project without identified participants, such as point-of-sale rebates and retailer or manufacturer incentive programs, track applicable vendor, retailer, and manufacturer data.

(3) For EE programs (such as those implemented by a utility) and EE projects (such as those implemented by an energy service company) that both have identified participants, use tracking data to avoid and correct for double counting that may occur across the two; and

(4) For EE programs with identified participants and those without (such as retail incentives to purchase energy-efficient equipment), use EE program tracking data for the former and use applicable vendor, retailer, and manufacturer data for the latter to avoid and correct for double counting that may occur across the two.

(D) The EE savings verification approaches for ensuring that EE measures have been properly installed, are operating as intended, and therefore have the potential to save electricity, including how verification will be carried out within the first year of implementation of the EE program, EE project, or EE measure using best-practice approaches, such as physical inspections at a customer's premises, phone and mail surveys, and reviews of sales receipts and other documentation. If such approaches are documented in EM&V guidance issued by the Administrator, they will be treated as acceptable.

(E) The interactive effects of EE programs, EE projects, or EE measures on electricity usage, which are increases or decreases in electricity usage at an end-use facility or premises that occurs outside of specific end-uses(s) targeted by the EE program, EE project, or EE measure (*e.g.,* lighting retrofits to improve EE can reduce waste heat to the surrounding conditioned space, and therefore may increase the required electric heating load in a facility or premises).

(vii) The EM&V plan must specify how the accuracy and reliability of the electricity savings of the EE program, EE project, or EE measure will be assessed, and must discuss the rigor of the method selected to quantify the electricity savings. It must also discuss the approaches that will be used to control all relevant types of bias and to minimize the potential for systematic and random error, as well as the program- or project-specific circumstances in which such bias and error are likely to arise. Approaches to minimizing bias and error are provided in the EM&V guidance that may be issued by the Administrator will be acceptable.

(viii) If sampling will be used to quantify the electricity savings from an EE program, then the MWh estimates derived from sampling must have at least 90 percent confidence intervals whose end points are no more than ±10 percent of the estimate, and the statistical precision of the associated estimates must be specified in the EM&V plan.

(ix) All data sources and key assumptions used to quantify electricity savings must be described in the EM&V plan.

(x) Any additional information necessary to demonstrate that the electricity savings were appropriately quantified and verified. Approaches to quantifying and verifying savings from several EE program and EE project types that are provided in EM&V guidance that may be issued by the Administrator will be acceptable.

(d) You must ensure that any EM&V plan submitted pursuant to this subpart includes the following certification:

(1) ''I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.''

(2) [Reserved]

§ 62.16460 What are the requirements for monitoring and verification reports for eligible resources?

(a) *M&V report requirements.* Any M&V report that is submitted, in support of the issuance of an ERC that can be used in accordance with § 62.16420, must meet the requirements of this section.

(b) *General M&V report criteria.* Each M&V report must include the following:

(1) For the first M&V report submitted, documentation that the electricity-generating resources, electricity-saving measures, or practices were installed or implemented consistent with the description in the approved eligibility application required in § 62.16445(a); and

(2) For each M&V report submitted:

(i) Identification of the time period covered by the M&V report;

(ii) A description of how relevant quantification methods, protocols, guidelines, and guidance specified in the EM&V plan were applied during the reporting period to generate the quantified MWh of generation or MWh of electricity savings;

(iii) Documentation (including data) of the energy generation and/or electricity savings from any activity, project, measure, resource, or program addressed in the EM&V report, quantified and verified in MWh for the period covered by the M&V report, in accordance with its EM&V plan, and based on ex-post energy generation or savings;

(iv) Documentation of any change in the energy generation or savings capability of the eligible resource during the period covered by the M&V report and the date on which the change occurred, and either certification that the eligible resource continued to meet all eligibility requirements during the reporting period covered by the M&V report or disclosure of any material changes to the eligible resource from the description of the eligible resource in the approved eligibility application, which must include any change in the energy generation (*e.g.,* nameplate MW capacity) or electricity savings capability of the qualifying eligible resource (including the date of the change); and

(v) Documentation of any change in ownership interest of the qualifying eligible resource (including the date of the change).

(c) You must ensure that any M&V report submitted pursuant to this subpart includes the following certification:

(1) ''I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.''

(2) [Reserved]

§ 62.16465 What are the requirements for verification reports?

(a) A verification report included as part of an eligibility application or an M&V report must meet the requirements of paragraph (b) of this section (for the eligibility application verification report) and paragraph (c) of this section (for the M&V report verification report) and include the following:

(1) A verification statement that sets forth the findings of the accredited independent verifier, based on the verifier's assessment of the information and data in the eligibility application or M&V report that is the subject of the verification report, including an assessment of whether the eligibility application or M&V report contains any material misstatements or material data discrepancies, and whether the submittal conforms with applicable regulatory requirements. The verification statement must clearly identify how levels of assurance and materiality are defined as part of the verifier assessment.

(2) The following statement, signed by the accredited independent verifier: ''I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my personal knowledge and/or inquiry of those individuals with primary responsibility

for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.''

(b) A verification report included as part of an eligibility application must, at a minimum, describe the review conducted by the accredited independent verifier and verify each of the following:

(1) The eligibility of the eligible resource to be issued ERCs pursuant to this regulation, in accordance with § 62.16435 and § 62.16445(a), including an analysis of the adequacy and validity of the information submitted by the authorized account representative to demonstrate that the eligible resource meets each applicable requirement of § 62.16435 and § 62.16445(a).

(2) The eligible resource is not duplicative of a resource used to meet emission standards or a state measure in another approved State plan.

(3) The eligible resource exists or the practice or activity will be implemented in the manner specified in the eligibility application.

(4) The EM&V plan meets the requirements of § 62.16455.

(5) Disclosure of any mandatory or voluntary programs to which data is reported relating to the eligible resource (*e.g.,* reporting of electric generation by a renewable energy resource to a renewable energy certificate tracking system).

(6) Any other information required by the Administrator or that the accredited independent verifier finds, in its professional opinion, is necessary to assess the adequacy and validity of information and data supplied by the authorized account representative.

(c) A verification report included as part of a M&V report must, at a minimum, describe the review conducted by the accredited independent verifier and verify the following:

(1) The adequacy and validity of the information and data submitted in the submittal by the authorized account representative to quantify eligible MWh of electric generation or electricity savings during the period for which the authorized account representative seeks issuance of ERCs, as well as all supporting information and data identified in the EM&V plan and M&V report. This analysis must include a quality assurance and quality control check of the data and ensure that all generation or savings data are within a technically feasible range for that specific eligible resource.

(i) For metered generation, the data validity check must compare reported electricity generation to an engineering estimate of the maximum generation potential of the qualified renewable energy resource, based on, at a minimum, its maximum nameplate capacity in MW and the number of days since the prior cumulative meter reading was entered in the ERC tracking system. If the data entered exceed the estimated technically feasible generation, then the reported data and the estimate must be analyzed in the verification report.

(ii) For all electricity generated or saved, the accredited independent verifier must describe the likely source of any data discrepancy and determine in the verification report any MWh generated or saved.

(2) The M&V report meets the requirements of § 62.16460.

(3) Any other information required by the Administrator or that the accredited independent verifier finds, in its professional opinion, is necessary to assess the adequacy and validity of information and data supplied by the authorized account representative.

§ 62.16470 What is the accreditation procedure for independent verifiers?

(a) Only Administrator-accredited independent verifiers may provide a verification report for an eligibility application or M&V report.

(b) Applications for accreditation must follow a procedure and form specified by the Administrator which includes a demonstration by the verifier that it meets the requirements in paragraph (c) of this section.

(c) Independent verifiers must meet each of the requirements in paragraphs (c)(1) through (6) of this section to be accredited.

(1) Independent verifiers must have the skills, experience, and resources (personnel and otherwise) to provide verification reports, including the following:

(i) Appropriate technical qualification (professional engineer or otherwise) to evaluate the eligible resource for which the independent verifier is seeking accreditation, which may include ANSI accreditation under ISO 14065 for GHG validation and verification bodies;

(ii) Appropriate auditing and accounting qualifications for financial and non-financial data monitoring, auditing, and quality assurance and quality control to evaluate the eligible resource for which the independent verifier is seeking accreditation;

(iii) Knowledge of the requirements of the Administrator's CO_2 Rate-based Trading Program regulations and related guidance;

(iv) Knowledge of the eligible resource categories for which the independent verifier is seeking accreditation, including relevant aspects of the design, operation, and related energy generation or electricity savings monitoring and reporting approaches for such eligible resources; and

(v) Capability to perform key verification activities, such as development of a verification report; performance of site visits; review and recalculation of reported data; review of data management systems; review of quantification methods used in accordance with an approved EM&V plan; preparation of a verification statement, list of findings, and verification report; and internal review of the verification findings and report.

(2) Independent verifiers must document, in the application for accreditation, the independent verifiers that will provide verification services, including lead verifiers, key personnel and any contractors or subcontractors (collectively, accredited independent verification team) and demonstrate that they meet the requirements of section § 62.16470(d)(1). Once accredited, only the accredited independent verification team identified in the accreditation application and accredited by the State may provide a verification report.

(3) An independent verifier must specify the eligible resource categories for which it is seeking accreditation, and an accredited independent verifier may only provide verification services related to an eligible resource category for which it is accredited.

(4) Prospective independent verifiers must meet the requirements of § 62.16475(d) through (f) and demonstrate that they have in place adequate systems and protocols to identify, disclose and avoid potential conflicts of interest.

(5) An accredited independent verifier must not be debarred, suspended, or proposed for debarment pursuant to the Government-wide Debarment and Suspension regulations, part 32 of this chapter, or the Debarment, Suspension and Ineligibility provisions of the Federal Acquisition Regulations, 48 CFR part 9, subpart 9.4.

(6) An accredited independent verifier must maintain, for its employees, and ensure the maintenance of, for any parties that it employs, professional liability insurance, as defined in 31 CFR 50.5(q), through an insurance provider that possesses a financial strength rating in the top four categories from either

Standard & Poor's or Moody's, specifically, AAA, AA, A or BBB for Standard & Poor's, and Aaa, Aa, A, or Baa for Moody's. Any entity covered by this paragraph must disclose the level of professional liability insurance they possess when entering into contracts to provide verification services pursuant to this regulation.

(d) Requirements for maintenance of accreditation status, as follows:

(1) Accredited independent verifiers must meet the requirements of § 62.16475 when providing verification services for an authorized account representative; and

(2) The instances specified in § 62.16475(d) are cause for revocation of a verifier's accreditation.

§ 62.16475 What are the procedures of accredited independent verifiers must follow to avoid conflict of interest?

(a) Accredited independent verifiers must not provide verification services for any eligible resource for which it has a conflict of interest (COI), which means:

(1) Accredited independent verifiers must have, or have had, no direct or indirect financial interest in, or other financial relationships with, an eligible resource, or any prospective eligible resource, for which they seek to provide a verification report;

(2) Accredited independent verifiers must have, or have had, no direct or indirect organizational or personal relationships with an eligible resource, that would impact their impartiality in assessing the validity and accuracy of the information in an eligibility application or M&V report;

(3) Accredited independent verifiers must have, or have had, no role in the development and implementation of an eligible resource for which an authorized account representative seeks issuance of ERCs, beyond the provision of verification services;

(4) Accredited independent verifiers must not be compensated, financially or otherwise, directly or indirectly, on the basis of the content of its verification report (including eligibility approval of an eligible resource, the quantified and verified MWh in an M&V report, ERC issuance, or the number of ERCs issued);

(5) Accredited independent verifiers must not own, buy, sell, or hold ERCs, or other financial derivatives related to ERCs, or have a financial relationship with other parties that own, buy, sell, or hold ERCs or other related financial derivatives;

(6) An accredited independent verifier must not be incapable of providing an impartial verification report for any other reason; and

(7) An accredited independent verifier must ensure that the subject of any verification report must not have the opportunity to review or influence any draft or final verification report before its submittal to the Administrator, and the accredited independent verifier must share any drafts of its reports with the Administrator at the same time as it shares them with the subject of the report.

(b) A contract with an eligible resource for the provision of verification services will not constitute a COI.

(c) Verification reports must include an attestation by the accredited independent verifier that it evaluated and disclosed to the Administrator any potential COI related to an eligible resource.

(d) Prior to engaging for the provision of verification services, an accredited independent verifier must demonstrate that it has no COI related to the eligible resource, as specified in paragraph (a) of this section. If a COI is identified for a person or persons within an accredited independent verifier for a specific subject or verification, in accordance with paragraphs (e) and (f) of this section, then an accredited independent verifier may propose to the Administrator steps that will be taken to eliminate the COI which include prohibiting the person or persons with the conflict from any involvement in the matter subject to the conflict, including verification services, access to information related to the verification services, access to any draft or final verification reports, any communications with the person(s) conducting the verification services. In no instance shall an accredited independent verifier engage in verification services for an eligible resource without the approval of the Administrator.

(e) Prior to engaging in verification services and writing a verification report, an accredited independent verifier must disclose to the Administrator all information necessary for the Administrator to evaluate a potential COI (including information concerning its ownership, past and current clients, related entities, as well as any other facts or circumstances that have the potential to create a COI).

(f) Accredited verifiers have an ongoing obligation to disclose to the Administrator any facts or circumstances that may give rise to a COI as defined in paragraph (a) of this section.

(g) The Administrator may reject a verification report from an accredited independent verifier, if the Administrator determines that the accredited independent verifier has a COI as defined in paragraph (a) of this section. If the Administrator rejects an accredited independent verifier report for such reasons, then the eligibility application or M&V report submittal shall be deemed incomplete and ERCs must not be issued pursuant to it.

§ 62.16480 What is the process for the revocation of accreditation status for an independent verifier?

(a) The Administrator may revoke the accreditation of an independent verifier at any time for cause, including for the reasons specified in paragraphs (a)(1) through (4) of this section.

(1) Failure to fully disclose any issues that may lead to a COI with respect to an eligible resource, or other related entity, in accordance with § 62.16475(d) through (f).

(2) The accredited independent verifier is no longer qualified to provide verification services.

(3) Negligence in the conduct of verification activities, or neglect of responsibilities pursuant to the requirements of §§ 62.16465, 62.16470, and 62.16475.

(4) Intentional misrepresentation of data in a verification report.

(b) [Reserved]

Designated Representatives

§ 62.16485 How are designated representatives and alternate designated representatives authorized and what role do authorized designated representatives and alternate designated representatives play?

(a) Except as provided under § 62.16495, each affected EGU, and each eligible resource shall have one and only one designated representative, with regard to all matters under the CO_2 Rate-based Trading Program.

(1) The designated representative shall be selected by an agreement binding on the owners and operators of the affected EGU and must act in accordance with the certification statement in § 62.16500(a)(4)(iii).

(2) Upon and after receipt by the Administrator of a complete certificate of representation under § 62.16500:

(i) The designated representative shall be authorized and shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each owner and operator of the affected EGU in all matters pertaining to the CO_2 Rate-based Trading Program, notwithstanding any agreement between the designated representative and such owners and operators; and

(ii) The owners and operators of the affected EGU shall be bound by any decision or order issued to the designated representative by the

Administrator regarding the affected EGU.

(b) Except as provided under § 62.16495, each affected EGU may have one and only one alternate designated representative, who may act on behalf of the designated representative. The agreement by which the alternate designated representative is selected must include a procedure for authorizing the alternate designated representative to act in lieu of the designated representative.

(1) The alternate designated representative shall be selected by an agreement binding on the owners and operators of the affected EGU and must act in accordance with the certification statement in § 62.16500(a)(4)(iii).

(2) Upon and after receipt by the Administrator of a complete certificate of representation under § 62.16500,

(i) The alternate designated representative must be authorized;

(ii) Any representation, action, inaction, or submission by the alternate designated representative shall be deemed to be a representation, action, inaction, or submission by the designated representative; and

(iii) The owners and operators of the affected EGU shall be bound by any decision or order issued to the alternate designated representative by the Administrator regarding any such affected EGU.

(c) Except in this section, §§ 62.16490 through 62.16510, and § 62.16570, whenever the term ''designated representative'' (as distinguished from the term ''common designated representative'') is used in this subpart, the term shall be construed to include the designated representative.

§ 62.16490 What responsibilities do designated representatives and alternate designated representatives hold?

(a) Except as provided under § 62.16510 concerning delegation of authority to make submissions, each submission under the CO_2 Rate-based Trading Program must be made, signed, and certified by the designated representative or alternate designated representative for each affected EGU for which the submission is made. Each such submission must include the following certification statement by the designated representative or alternate designated representative: ''I am authorized to make this submission on behalf of the owners and operators of the affected EGU for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.''

(b) The Administrator will accept or act on a submission made for an affected EGU only if the submission has been made, signed, and certified in accordance with paragraph (a) of this section and § 62.16510.

§ 62.16495 What are the processes for changing designated representatives, alternate designated representatives, owners and operators, and affected EGUs?

(a) *Changing designated representative.* The designated representative may be changed at any time upon receipt by the Administrator of a superseding complete certificate of representation under § 62.16500. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous designated representative before the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new designated representative and the owners and operators of the affected EGU.

(b) *Changing alternate designated representative.* The alternate designated representative may be changed at any time upon receipt by the Administrator of a superseding complete certificate of representation under § 62.16500. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous alternate designated representative before the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new alternate designated representative, the designated representative, and the owners and operators of the affected EGU.

(c) *Changes in owners and operators.* (1) In the event an owner or operator of an affected EGU is not included in the list of owners and operators in the certificate of representation under § 62.16500, such owner or operator shall be deemed to be subject to and bound by the certificate of representation, the representations, actions, inactions, and submissions of the designated representative and any alternate designated representative of the affected EGU, and the decisions and orders of the Administrator, as if the owner or operator were included in such list.

(2) Within 30 days after any change in the owners and operators of affected EGU, including the addition or removal of an owner or operator, the designated representative or any alternate designated representative must submit a revision to the certificate of representation under § 62.16500 amending the list of owners and operators to reflect the change.

(d) *Changes in affected EGUs at the source.* Within 30 days of any change in which affected EGUs are located at a source (including the addition or removal of an affected EGU), the designated representative or any alternate designated representative must submit a certificate of representation under § 62.16500 amending the list of affected EGUs to reflect the change.

(1) If the change is the addition of an affected EGU that operated (other than for purposes of testing by the manufacturer before initial installation) before being located at the source, then the certificate of representation must identify, in a format prescribed by the Administrator, the entity from whom the affected EGU was purchased or otherwise obtained (including name, address, telephone number, and facsimile transmission number (if any)), the date on which the affected EGU was purchased or otherwise obtained, and the date on which the affected EGU became located at the source.

(2) If the change is the removal of an affected EGU, then the certificate of representation must identify, in a format prescribed by the Administrator, the entity to which the affected EGU was sold or that otherwise obtained the affected EGU (including name, address, telephone number, and facsimile transmission number (if any)), the date on which the affected EGU was sold or otherwise obtained, and the date on which the affected EGU became no longer located at the source.

§ 62.16500 What must be included in a certificate of representation?

(a) A complete certificate of representation for a designated representative or an alternate designated representative must include the elements in paragraphs (a)(1) through (5) of this section in a format prescribed by the Administrator.

(1) Identification of the affected EGU for which the certificate of representation is submitted, including names, source category and NAICS code (or, in the absence of a NAICS code, an equivalent code), State, plant code, county, latitude and longitude, unit identification number and type,

identification number and nameplate capacity (in MWe, rounded to the nearest tenth) of each generator served by each such affected EGU, net-summer capacity, actual or projected date of commencement of commercial operation, and a statement of whether such affected EGU is located in Indian country. If a projected date of commencement of commercial operation is provided, then the actual date of commencement of commercial operation must be provided when such information becomes available.

(2) The name, address, email address (if any), telephone number, and facsimile transmission number (if any) of the designated representative and any alternate designated representative.

(3) A list of the owners and operators of the affected EGU.

(4) The following certification statements by the designated representative and any alternate designated representative:

(i) ''I certify that I was selected as the designated representative or alternate designated representative, as applicable, by an agreement binding on the owners and operators of the affected EGU'';

(ii) ''I certify that I have all the necessary authority to carry out my duties and responsibilities under the CO_2 Rate-based Trading Program on behalf of the owners and operators of the affected EGU and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions and by any decision or order issued to me by the Administrator regarding the affected EGU''; and

(iii) ''Where there are multiple holders of a legal or equitable title to, or a leasehold interest in, an affected EGU, or where a utility or industrial customer purchases power from an affected EGU under a life-of-the-unit, firm power contractual arrangement, I certify that: I have given a written notice of my selection as the 'designated representative' or 'alternate designated representative', as applicable, and of the agreement by which I was selected to each owner and operator of the affected EGU; and ERCs and proceeds of transactions involving CO_2 Rate-based Trading Program allowances will be deemed to be held or distributed in proportion to each holder's legal, equitable, leasehold, or contractual reservation or entitlement, except that, if such multiple holders have expressly provided for a different distribution of ERCs by contract, ERCs and proceeds of transactions involving CO_2 Rate-based Trading Program ERCs will be deemed to be held or distributed in accordance with the contract.''

(5) The signature of the designated representative and any alternate designated representative and the dates signed.

(b) Unless otherwise required by the Administrator, documents of agreement referred to in the certificate of representation shall not be submitted to the Administrator. The Administrator shall not be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

§ 62.16505 What is the Administrator's role in objections concerning designated representatives and alternate designated representatives?

(a) Once a complete certificate of representation under § 62.16500 has been submitted and received, the Administrator will rely on the certificate of representation unless and until a superseding complete certificate of representation under § 62.16500 is received by the Administrator.

(b) Except as provided in paragraph (a) of this section, no objection or other communication submitted to the Administrator concerning the authorization, or any representation, action, inaction, or submission, of a designated representative or alternate designated representative shall affect any representation, action, inaction, or submission of the designated representative or alternate designated representative or the finality of any decision or order by the Administrator under the CO_2 Rate-based Trading Program.

(c) The Administrator will not adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of any designated representative or alternate designated representative, including private legal disputes concerning the proceeds of ERC transfers.

§ 62.16510 What process must designated representatives and alternate designated representatives follow to delegate their authority?

(a) A designated representative may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(b) An alternate designated representative may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(c) In order to delegate authority to a natural person to make an electronic submission to the Administrator in accordance with paragraph (a) or (b) of this section, the designated representative or alternate designated representative, as appropriate, must submit to the Administrator a notice of delegation, in a format prescribed by the Administrator, that includes the following elements:

(1) The name, address, email address, telephone number, and facsimile transmission number (if any) of such designated representative or alternate designated representative;

(2) The name, address, email address, telephone number, and facsimile transmission number (if any) of each such natural person (referred to in this section as an ''agent'');

(3) For each such natural person, a list of the type or types of electronic submissions under paragraph (a) or (b) of this section for which authority is delegated to him or her; and

(4) The following certification statements by such designated representative or alternate designated representative:

(i) ''I agree that any electronic submission to the Administrator that is made by an agent identified in this notice of delegation and of a type listed for such agent in this notice of delegation and that is made when I am a designated representative or alternate designated representative, as appropriate, and before this notice of delegation is superseded by another notice of delegation under § 62.16510(d) shall be deemed to be an electronic submission by me''; and

(ii) ''Until this notice of delegation is superseded by another notice of delegation under § 62.16510(d), I agree to maintain an email account and to notify the Administrator immediately of any change in my email address unless all delegation of authority by me under § 62.16510 is terminated.''

(d) A notice of delegation submitted under paragraph (c) of this section shall be effective, with regard to the designated representative or alternate designated representative identified in such notice, upon receipt of such notice by the Administrator and until receipt by the Administrator of a superseding notice of delegation submitted by such designated representative or alternate designated representative, as appropriate. The superseding notice of delegation may replace any previously identified agent, add a new agent, or eliminate entirely any delegation of authority.

(e) Any electronic submission covered by the certification in paragraph (c)(4)(i) of this section and made in accordance with a notice of delegation effective under paragraph (d) of this section shall be deemed to be an electronic submission by the designated representative or alternate designated representative submitting such notice of delegation.

Monitoring, Recordkeeping, Reporting

§ 62.16515 How are compliance accounts and general accounts established and used, and how is ERC issuance documentation accessed?

(a) *Compliance accounts.* (1) Upon receipt of a complete certificate of representation under § 62.16500, the Administrator will establish a compliance account for the affected EGU for which the certificate of representation was submitted, unless the affected EGU already has a compliance account. The designated representative and any alternate designated representative of an affected EGU shall be the authorized account representative and the alternate authorized account representative, respectively, of the compliance account.

(2) A compliance account will hold ERCs intended for surrender by a designated representative when demonstrating an affected EGUs compliance with a CO_2 emission standard as applicable in § 62.16420. A compliance account may be established for a facility with one or more affected EGUs, provided that the account contains subaccounts for each affected EGU within the facility.

(b) *Retirement accounts.* (1) A retirement account, into which ERCs held in a compliance account for an affected EGU are surrendered by the owner or operator of an affected EGU, for use in demonstrating compliance with its emission standards. The retirement account may only be held by the Administrator, and ERCs deposited into it are permanently retired. Once an ERC is retired, the ERC shall no longer be transferable to another account in that ERC tracking system or any other ERC tracking system.

(2) [Reserved]

(c) *General accounts*—(1) *Application for a general account.* (i) Designated representatives of affected EGUs, authorized account representatives of eligible resources, and any other person may apply to open a general account, for the purpose of holding and transferring ERCs, by submitting to the Administrator a complete application for a general account. Such application must designate one and only one authorized account representative and may designate one and only one alternate authorized account representative who may act on behalf of the authorized account representative.

(A) The authorized account representative and alternate authorized account representative shall be selected by an agreement binding on the persons who have an ownership interest with respect to ERCs held in the general account.

(B) The agreement by which the alternate authorized account representative is selected must include a procedure for authorizing the alternate authorized account representative to act in lieu of the authorized account representative.

(ii) A complete application for a general account must include the following elements in a format prescribed by the Administrator:

(A) Name, mailing address, email address (if any), telephone number, and facsimile transmission number (if any) of the authorized account representative and any alternate authorized account representative;

(B) An identifying name for the general account;

(C) A list of all persons subject to a binding agreement for the authorized account representative and any alternate authorized account representative to represent their ownership interest with respect to the ERCs held in the general account;

(D) The following certification statement by the authorized account representative and any alternate authorized account representative: ''I certify that I was selected as the authorized account representative or the alternate authorized account representative, as applicable, by an agreement that is binding on all persons who have an ownership interest with respect to ERCs held in the general account. I certify that I have all the necessary authority to carry out my duties and responsibilities under the CO_2 Rate-based Trading Program on behalf of such persons and that each such person shall be fully bound by my representations, actions, inactions, or submissions and by any decision or order issued to me by the Administrator regarding the general account''; and

(E) The signature of the authorized account representative and any alternate authorized account representative and the dates signed.

(iii) Unless otherwise required by the Administrator, documents of agreement referred to in the application for a general account shall not be submitted to the Administrator. The Administrator shall not be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

(2) *Authorization of authorized account representative and alternate authorized account representative.* (i) Upon receipt by the Administrator of a complete application for a general account under paragraph (c)(1) of this section, the Administrator will establish a general account for the person or persons for whom the application is submitted, and upon and after such receipt by the Administrator:

(A) The authorized account representative of the general account shall be authorized and shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each person who has an ownership interest with respect to ERCs held in the general account in all matters pertaining to the CO_2 Rate-based Trading Program, notwithstanding any agreement between the authorized account representative and such person;

(B) Any alternate authorized account representative shall be authorized, and any representation, action, inaction, or submission by any alternate authorized account representative shall be deemed to be a representation, action, inaction, or submission by the authorized account representative; and

(C) Each person who has an ownership interest with respect to ERCs held in the general account shall be bound by any decision or order issued to the authorized account representative or alternate authorized account representative by the Administrator regarding the general account.

(ii) Except as provided in paragraph (c)(5) of this section concerning delegation of authority to make submissions, each submission concerning the general account must be made, signed, and certified by the authorized account representative or any alternate authorized account representative for the persons having an ownership interest with respect to ERCs held in the general account. Each such submission must include the following certification statement by the authorized account representative or any alternate authorized account representative: ''I am authorized to make this submission on behalf of the persons having an ownership interest with respect to the ERCs held in the general account. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.''

(iii) Except in this section, whenever the term ''authorized account representative'' is used in this subpart, the term shall be construed to include the authorized account representative or any alternate authorized account representative.

(3) Changing authorized account representative and alternate authorized account representative; changes in persons with ownership interest.

(i) The authorized account representative of a general account may be changed at any time upon receipt by the Administrator of a superseding complete application for a general account under paragraph (c)(1) of this section. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous authorized account representative before the time and date when the Administrator receives the superseding application for a general account shall be binding on the new authorized account representative and the persons with an ownership interest with respect to the ERCs in the general account.

(ii) The alternate authorized account representative of a general account may be changed at any time upon receipt by the Administrator of a superseding complete application for a general account under paragraph (c)(1) of this section. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous alternate authorized account representative before the time and date when the Administrator receives the superseding application for a general account shall be binding on the new alternate authorized account representative, the authorized account representative, and the persons with an ownership interest with respect to the ERCs in the general account.

(iii)(A) In the event a person having an ownership interest with respect to ERCs in the general account is not included in the list of such persons in the application for a general account, such person shall be deemed to be subject to and bound by the application for a general account, the representation, actions, inactions, and submissions of the authorized account representative and any alternate authorized account representative of the account, and the decisions and orders of the Administrator, as if the person were included in such list.

(B) Within 30 days after any change in the persons having an ownership interest with respect to ERCs in the general account, including the addition or removal of a person, the authorized account representative or any alternate authorized account representative must submit a revision to the application for a general account amending the list of persons having an ownership interest with respect to the ERCs in the general account to include the change.

(4) Objections concerning authorized account representative and alternate authorized account representative.

(i) Once a complete application for a general account under paragraph (c)(1) of this section has been submitted and received, the Administrator will rely on the application unless and until a superseding complete application for a general account under paragraph (c)(1) of this section is received by the Administrator.

(ii) Except as provided in paragraph (c)(4)(i) of this section, no objection or other communication submitted to the Administrator concerning the authorization, or any representation, action, inaction, or submission of the authorized account representative or any alternate authorized account representative of a general account shall affect any representation, action, inaction, or submission of the authorized account representative or any alternate authorized account representative or the finality of any decision or order by the Administrator under the CO_2 Rate-based Trading Program.

(iii) The Administrator will not adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of the authorized account representative or any alternate authorized account representative of a general account, including private legal disputes concerning the proceeds of ERCs transfers.

(5) Delegation by authorized account representative and alternate authorized account representative.

(i) An authorized account representative of a general account may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(ii) An alternate authorized account representative of a general account may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(iii) In order to delegate authority to a natural person to make an electronic submission to the Administrator in accordance with paragraph (c)(5)(i) or (ii) of this section, the authorized account representative or alternate authorized account representative, as appropriate, must submit to the Administrator a notice of delegation, in a format prescribed by the Administrator, that includes the following elements:

(A) The name, address, email address, telephone number, and facsimile transmission number (if any) of such authorized account representative or alternate authorized account representative;

(B) The name, address, email address, telephone number, and facsimile transmission number (if any) of each such natural person (referred to in this section as an ''agent'');

(C) For each such natural person, a list of the type or types of electronic submissions under paragraph (c)(5)(i) or (ii) of this section for which authority is delegated to him or her;

(D) The following certification statement by such authorized account representative or alternate authorized account representative: ''I agree that any electronic submission to the Administrator that is made by an agent identified in this notice of delegation and of a type listed for such agent in this notice of delegation and that is made when I am an authorized account representative or alternate authorized representative, as appropriate, and before this notice of delegation is superseded by another notice of delegation under § 62.16515(c)(5)(iv) shall be deemed to be an electronic submission by me''; and

(E) The following certification statement by such authorized account representative or alternate authorized account representative: ''Until this notice of delegation is superseded by another notice of delegation under § 62.16515(c)(5)(iv), I agree to maintain an email account and to notify the Administrator immediately of any change in my email address unless all delegation of authority by me under § 62.16515(c)(5) is terminated.''

(iv) A notice of delegation submitted under paragraph (c)(5)(iii) of this section shall be effective, with regard to the authorized account representative or alternate authorized account representative identified in such notice, upon receipt of such notice by the Administrator and until receipt by the Administrator of a superseding notice of delegation submitted by such authorized account representative or alternate authorized account representative, as appropriate. The superseding notice of delegation may replace any previously identified agent, add a new agent, or eliminate entirely any delegation of authority.

(v) Any electronic submission covered by the certification in paragraph (c)(5)(iii)(D) of this section and made in accordance with a notice of delegation effective under paragraph (c)(5)(iv) of this section shall be deemed to be an electronic submission by the authorized account representative or alternate authorized account representative submitting such notice of delegation.

(6) *Closing a general account.* (i) The authorized account representative or alternate authorized account representative of a general account may submit to the Administrator a request to close the account. Such request must include a correctly submitted ERC transfer under § 62.16525 for any ERCs in the account to one or more other ATCS accounts.

(ii) If a general account has no ERC transfers to or from the account for a 12-month period or longer and does not contain any ERCs, then the Administrator may notify the authorized account representative for the account that the account will be closed 30 days after the notice is sent. The account will be closed after the 30-day period unless, before the end of the 30-day period, the Administrator receives a correctly submitted ERC transfer under § 62.16525 to the account or a statement submitted by the authorized account representative or alternate authorized account representative demonstrating to the satisfaction of the Administrator good cause as to why the account should not be closed.

(d) *Account identification.* The Administrator will assign a unique identifying number to each account established under paragraphs (a) through (c) of this section.

(e) *Responsibilities of authorized account representative and alternate authorized account representative.* After the establishment of a compliance account or general account, the Administrator will accept or act on a submission pertaining to the account, including, but not limited to, submissions concerning the deduction or transfer of ERCs in the account, only if the submission has been made, signed, and certified in accordance with § 62.16490(a) and § 62.16510 or paragraphs (c)(2)(ii) and (5) of this section.

(f) *ERC identification information.* The Administrator will assign to each ERC issued in the EPA ERC tracking system a unique serial identifier that begins with the two digit postal abbreviation of the State in which it was issued and includes the year it was issued, and the eligible resource category that generated it.

(g) *Records supporting ERC issuance.* The Administrator will maintain in the EPA ERC tracking system records of, for each ERC, all of the following:

(1) Account holder names and information;

(2) Authorized account representative name and information;

(3) Qualifying eligible resource identification number, name, State, and contact information including street address, mailing address, phone number, and email;

(4) Category of qualifying eligible resource, according to the categories specified in § 62.16435(a)(4);

(5) The date the qualifying eligible resource commenced generation or saving of energy;

(6) Individual ERCs, each with a unique serial identifier that meets the requirements of paragraph (f) of this section;

(7) Records of ERC transfers among accounts, including the date of transfer and the accounts involved in the transfer;

(8) The date an ERC was surrendered for a compliance demonstration;

(9) Date an ERC was retired by the regulatory body; and

(10) Each eligibility application, EM&V plan, M&V report, and verification report associated with the issuance of each specific ERC, and each regulatory approval and any documentation that supports the issuance of each ERC by the Administrator.

(h) *Access to records supporting ERC issuance.* The Administrator will provide in the EPA ERC tracking system access and functionality to allow each ERC to be traceable by the public to the records listed in paragraph (g) of this section. This information will be accessible via an electronic, internet-based portal in the ERC tracking system searchable by, at a minimum, each eligible resource, affected EGU, eligible resource category, and ERC.

(i) *Reports.* The Administrator will provide in the EPA ERC tracking system electronic, internet-based access to enable the generation of at least the following reports, [for as long as this regulation is effective] [in perpetuity]:

(1) *Account activity reports.* By each account holder, reports based on records of their account activity, including the information listed in paragraph (g) of this section;

(2) *Public reports.* By the public, reports that include: All of the information listed in paragraph (g) of this section; a list of all registered account holders in the ERC tracking system, including compliance accounts and general accounts; a list of all eligible resources (including access to all documentation for such eligible resources); a list of all accredited independent verifiers; and aggregate ERC activity statistics on at least an annual basis, for at least the following: Issuance of ERCs, transfers among accounts, transfers in or out of the ERC tracking system to/from another approved ERC tracking system (if relevant), and ERC retirements. The ERC tracking system shall provide this functionality for as long as this regulation is effective; and

(3) *EPA reports.* For the EPA and state regulators, the information listed in paragraph (g) of this section and any other information regarding ERC issuance, transfer, surrender, and retirement for purpose of compliance with this regulation.

(j) *Interactions with other ERC tracking systems.* If approved in connection with a State plan, then an ERC tracking system may provide for transfers of ERCs to/from another ERC tracking system approved in connection with a State plan by the EPA, or provide for transfers of ERCs to/from an EPA-administered ERC tracking system used to administer a federal plan. To transfer ERCs to or from an EPA-administered ERC tracking system, the state ERC tracking system must be approved under subpart UUUU of part 60 of this chapter for such use by the EPA.

§ 62.16525 How must transfers of ERCs be submitted?

(a) An authorized account representative seeking recordation of an ERC transfer must submit the transfer to the Administrator.

(b) An ERC transfer is correctly submitted if:

(1) The transfer includes the following elements, in a format prescribed by the Administrator:

(i) The account numbers established by the Administrator for both the transferor and transferee accounts;

(ii) The serial number of each ERC that is in the transferor account and is to be transferred; and

(iii) The name and signature of the authorized account representative of the transferor account and the date signed; and

(2) When the Administrator attempts to record the transfer, the transferor account includes each ERC identified by serial number in the transfer.

§ 62.16530 When will ERC transfers be recorded?

(a) Except as provided in paragraph (b) of this section, within five business days of receiving an ERC transfer that is correctly submitted under § 62.16525, the Administrator will record an ERC transfer by moving each ERC from the transferor account to the transferee account as specified in the transfer.

(b) An ERC transfer to or from a compliance account that is submitted for recordation after the allowance transfer deadline for a compliance period and that includes any ERCs allocated for any compliance period before such allowance transfer deadline will not be recorded until after the Administrator completes the deductions from such compliance account under § 62.16535 for the compliance period immediately before such allowance transfer deadline.

(c) Where an ERC transfer is not correctly submitted under § 62.16525, the Administrator will not record such transfer.

(d) Within five business days of recordation of an ERC transfer under paragraphs (a) and (b) of the section, the Administrator will notify the authorized account representatives of both the transferor and transferee accounts.

(e) Within 10 business days of receipt of an ERC transfer that is not correctly submitted under § 62.16525, the Administrator will notify the authorized account representatives of both accounts subject to the transfer of:

(1) A decision not to record the transfer; and

(2) The reasons for such non-recordation.

§ 62.16535 How will deductions for compliance with a CO_2 emission standard occur?

For affected EGUs subject to the emission standards listed in Table 1 of this subpart, the owner or operator of an affected EGU must demonstrate compliance with its CO_2 emission standard in accordance with § 62.16420(c) and incorporate ERCs as listed in paragraphs (a) through (f) of this section.

(a) *Availability for deduction for compliance.* ERCs are available to be deducted from a compliance account and used for compliance with an affected EGU's CO_2 emissions standard for a compliance period only if the ERCs:

(1) Were allocated for a year in such compliance period or a prior compliance period; and

(2) Are held in the affected EGU's compliance account as of the allowance transfer deadline for such compliance period.

(b) *Deductions for compliance.* After the recordation, in accordance with § 62.16530, of ERC transfers submitted by the ERC transfer deadline for a compliance period, the Administrator will deduct from each affected EGU's compliance account ERCs available under paragraph (a) of this section in order to determine whether the affected EGU meets the CO_2 emission standard for such compliance period, as follows:

(1) Until the amount of ERCs deducted and subsequently added to the total MWh generated by the affected EGU adjusts the affected EGU's CO_2 emission rate to equal the CO_2 emission standard for such compliance period; or

(2) If there are insufficient ERCs to complete the deductions in paragraph (b)(1) of this section, until no more ERCs available under paragraph (a) of this section remain in the compliance account.

(c) *Identification of ERCs by serial number.* The authorized account representative for an affected EGU's compliance account may request that specific ERCs, identified by serial number, in the compliance account be deducted for emissions or excess emissions for a compliance period in accordance with paragraph (b) or (e) of this section. In order to be complete, such request must be submitted to the Administrator by the ERC transfer deadline for such compliance period and include, in a format prescribed by the Administrator, the identification of the affected EGU and the appropriate serial numbers.

(d) *First-in, first-out.* The Administrator will deduct ERCs under paragraph (b) or (e) of this section from the affected EGU's compliance account in accordance with a complete request under paragraph (c)(1) of this section or, in the absence of such request or in the case of identification of an insufficient amount of ERCs in such request, on a first-in, first-out accounting basis.

(e) *Deductions for exceeding the emission standard.* After making the deductions for compliance under paragraph (b) of this section for a compliance period in a year in which the affected EGU has exceeded its CO_2 emission standard, the Administrator will deduct from the affected EGU's compliance account an amount of ERCs, allocated for a compliance period in a prior year or the compliance period in the year of the excess emissions or in the immediately following year, equal to two times the number of ERCs of the affected EGU's excess emissions.

(f) *Recordation of deductions.* The Administrator will record in the appropriate compliance account all deductions from such an account under paragraphs (b) and (e) of this section.

§ 62.16540 What monitoring requirements must I comply with?

(a) You must follow the requirements described in paragraphs (a)(1) through (8) of this section to monitor emissions and net energy output at your affected EGU.

(1) The owner of operator of an affected EGU required to meet an emission standard must prepare a monitoring plan in accordance with the applicable provisions in § 75.53(g) and (h) of this chapter, unless such a plan is already in place under another program that requires CO_2 mass emissions to be monitored and reported according to part 75 of this chapter.

(2) Each compliance period shall include only ''valid operating hours'' in the compliance period, *i.e.,* operating hours for which:

(i) ''Valid data'' (as defined in § 62.16570) are obtained for all of the parameters used to determine the hourly CO_2 mass emissions (lbs). For the purposes of this subpart, substitute data recorded under part 75 of this chapter are not considered to be valid data; and

(ii) The corresponding hourly net energy output value is also valid data (Note: for hours with no useful output, zero is considered to be a valid value).

(3) The owner or operator of an affected EGU must measure and report the hourly CO_2 mass emissions (lbs) from each affected unit using the procedures in paragraphs (a)(3)(i) through (vii) of this section, except as provided in paragraph (a)(4) of this section.

(i) The owner or operator of an affected EGU must install, certify, operate, maintain, and calibrate a CO_2 continuous emissions monitoring system (CEMS) to directly measure and record CO_2 concentrations in the affected EGU exhaust gases emitted to the atmosphere and an exhaust gas flow rate monitoring system according to § 75.10(a)(3)(i) of this chapter. As an alternative to direct measurement of CO_2 concentration, the owner or operator of an affected EGU may use data from a certified oxygen (O_2) monitor to calculate hourly average CO_2 concentrations, in accordance with § 75.10(a)(3)(iii) of this chapter. If CO_2 concentration is measured on a dry basis, then you must also install, certify, operate, maintain, and calibrate a continuous moisture monitoring system, according to § 75.11(b) of this chapter. Alternatively, you may either use an appropriate fuel-specific default moisture value from § 75.11(b) or submit a petition to the Administrator under § 75.66 of this chapter for a site-specific default moisture value.

(ii) For each ''valid operating hour'', calculate the hourly CO_2 mass emission rate (tons/hr), either from Equation F–11 in Appendix F to part 75 of this chapter (if CO_2 concentration is measured on a wet basis), or by following the procedure in section 4.2 of Appendix F to part 75 of this chapter (if CO_2 concentration is measured on a dry basis).

(iii) Next, multiply each hourly CO_2 mass emission rate by the affected EGU or stack operating time in hours (as defined in § 72.2 of this chapter), to convert it to tons of CO_2. Multiply the result by 2000 lb/ton to convert it to lb.

(iv) The hourly CO_2 tons/hr values and affected EGU (or stack) operating times used to calculate CO_2 mass emissions are required to be recorded under § 75.57(e) of this chapter and must be reported electronically under § 75.64(a)(6). You must use these data to calculate the hourly CO_2 mass emissions.

(v) Sum all of the hourly CO_2 mass emissions values that were calculated according to procedures specified in paragraph (a)(3)(ii) of this section over the entire compliance period.

(vi) For each continuous monitoring system used to determine the CO_2 mass emissions from an affected EGU, the monitoring system must meet the applicable certification and quality assurance procedures in § 75.20 of this chapter and Appendices A and B to part 75 of this chapter.

(vii) The owner operator of an affected EGU must use only unadjusted exhaust gas volumetric flow rates to determine the hourly CO_2 mass emissions from the affected EGU; the owner or operator of an affected EGU must not apply the bias adjustment factors described in section 7.6.5 of Appendix A to part 75 of this chapter to the exhaust gas flow rate data.

(4) The owner or operator of an affected EGU that exclusively combusts liquid fuel and/or gaseous fuel may, as an alternative to complying with paragraph (a)(3) of this section, determine the hourly CO_2 mass emissions according to paragraphs (a)(4)(i) through (vi) of this section.

(i) Implement the applicable procedures in appendix D to part 75 of this chapter to determine hourly affected EGU heat input rates (MMBtu/h), based on hourly measurements of fuel flow rate and periodic determinations of the gross calorific value (GCV) of each fuel combusted.

(ii) For each measured hourly heat input rate, use Equation G–4 in Appendix G to part 75 of this chapter to calculate the hourly CO_2 mass emission rate (tons/hr).

(iii) For each valid operating hour (as defined in paragraph (a)(2) of this section, determine the hourly CO_2 mass emission rate (tons/hr) using the procedures specified in paragraph (a)(4)(ii) of this section and multiply it by the affected EGU or stack operating time in hours (as defined in § 72.2 of this chapter), to convert to tons of CO_2. Then, multiply the result by 2000 lb/ton to convert to lb.

(iv) The hourly CO_2 tons/hr values and affected EGU (or stack) operating times used to calculate CO_2 mass emissions are required to be recorded under § 75.57(e) of this chapter and must be reported electronically under § 75.64(a)(6). You must use these data to calculate the hourly CO_2 mass emissions.

(v) Sum all of the hourly CO_2 mass emissions values that were calculated according to procedures specified in paragraph (a)(4)(iii) of this section over the entire compliance period.

(vi) The owner or operator of an affected EGU may determine site-specific carbon-based F-factors (F_c) using Equation F–7b in section 3.3.6 of appendix F to part 75 of this chapter, and may use these F_c values in the emissions calculations instead of using the default F_c values in the Equation G–4 nomenclature.

(5) The owner or operator of an affected EGU must install, calibrate, maintain, and operate a sufficient number of watt meters to continuously measure and record on an hourly basis net electric output. Measurements must be performed using 0.2 accuracy class electricity metering instrumentation and calibration procedures as specified under ANSI Standards No. C12.20. Further, the owner or operator of an affected EGU that is a combined heat and power facility must install, calibrate, maintain and operate equipment to continuously measure and record on an hourly basis useful thermal output and, if applicable, mechanical output, which are used with net electric output to determine net energy output. The owner or operator must calculate net energy output according to paragraph (a)(5)(i) of this section.

(i) For each valid operating hour of a compliance period that was used in paragraph (a)(3) or (4) of this section to calculate the total CO_2 mass emissions, you must determine P_{net} (the corresponding hourly net energy output in MWh) according to the procedures in paragraphs (a)(5)(i)(A) and (B) of this section, as appropriate for the type of affected EGU(s). For an operating hour in which a valid CO_2 mass emissions value is determined according to paragraph (a)(3) or (4) of this section, if there is no gross or net electrical output, but there is mechanical or useful thermal output, then you must still determine the net energy output for that hour. In addition, for an operating hour in which a valid CO_2 mass emissions value is determined according to paragraph (a)(3) or (4) of this section, but there is no (*i.e.,* zero) gross electrical, mechanical, or useful thermal output, you must use that hour in the compliance determination. For hours or partial hours where the gross electric output is equal to or less than the auxiliary loads, net electric output shall be counted as zero for this calculation.

(A) Calculate P_{net} for your affected EGU using the following equation. All terms in the equation must be expressed in units of megawatt-hours (MWh). To convert each hourly net energy output value reported under part 75 of this chapter to MWh, multiply by the corresponding EGU or stack operating time.

$$P_{net} = \frac{(Pe)_{ST} + (Pe)_{CT} + (Pe)_{IE} - (Pe)_A}{TDF} + [(Pt)_{PS} + (Pt)_{HR} + (Pt)_{IE}]$$

Where:

P_{net} = Net energy output of your affected EGU for each valid operating hour (as defined in paragraph (a)(2) of this section) in MWh.

$(Pe)_{ST}$ = Electric energy output plus mechanical energy output (if any) of steam turbines in MWh.

$(Pe)_{CT}$ = Electric energy output plus mechanical energy output (if any) of stationary combustion turbine(s) in MWh.

$(Pe)_{IE}$ = Electric energy output plus mechanical energy output (if any) of your affected EGU's integrated equipment that provides electricity or mechanical energy to the affected EGU or auxiliary equipment in MWh.

$(Pe)_A$ = Electric energy used for any auxiliary loads in MWh.

$(Pt)_{PS}$ = Useful thermal output of steam (measured relative to SATP conditions as defined in § 62.16570, as applicable) that is used for applications that do not generate additional electricity, produce mechanical energy output, or enhance the performance of the affected EGU. This is calculated using the equation specified in paragraph (a)(5)(i)(B) of this section in MWh.

$(Pt)_{HR}$ = Non steam useful thermal output (measured relative to SATP conditions as defined in § 62.16570, as applicable) from heat recovery that is used for applications other than steam generation or performance enhancement of the affected EGU in MWh.

$(Pt)_{IE}$ = Useful thermal output (relative to SATP conditions, as applicable as defined in § 62.16570) from any integrated equipment is used for applications that do not generate additional steam, electricity, produce mechanical energy output, or enhance the performance of the affected EGU in MWh.

TDF = Electric Transmission and Distribution Factor of 0.95 for a combined heat and power affected EGU where at least on an annual basis 20.0 percent of the total net energy output consists of electric or direct mechanical output and 20.0 percent of the total net energy output consists of useful thermal output on a 12-operating month rolling average basis, or 1.0 for all other affected EGUs.

(B) If applicable to your affected EGU (for example, for combined heat and power), then you must calculate $(Pt)_{PS}$ using the following equation:

$$(Pt)_{PS} = \frac{Q_m \times H}{CF}$$

Where:

$(Pt)_{ps}$ = Useful thermal output of steam (measured relative to SATP conditions as defined in § 62.16570, as applicable) that is used for applications that do not generate additional electricity, produce mechanical energy output, or enhance the performance of the affected EGU.

Q_m = Measured steam flow in kilograms (kg) (or pounds (lb)) for the operating hour.

H = Enthalpy of the steam at measured temperature and pressure (relative to SATP conditions as defined in § 62.16570 or the energy in the condensate return line, as applicable) in Joules per kilogram (J/kg) (or Btu/lb).

CF = Conversion factor of 3.6×10^9 J/MWh or 3.413×10^6 Btu/MWh.

(C) Sum all of the values of P_{net} over the entire compliance period. Then, divide the total CO_2 mass emissions from paragraph (a)(3)(v) or (a)(4)(v) of this section, as applicable, by the sum of the P_{net} values to determine the CO_2 emission rate (lb/net MWh) for the compliance period.

(ii) [Reserved]

(6) In accordance with § 60.13(g) of this chapter, if two or more affected EGUs implementing the continuous emissions monitoring provisions in paragraph (a)(2) of this section share a common exhaust gas stack and are subject to the same emission standard, then the owner or operator may monitor the hourly CO_2 mass emissions at the common stack in lieu of monitoring each EGU separately. If an owner or operator of an affected EGU chooses this option, then the hourly net electric output for the common stack must be the sum of the hourly net electric output of the individual affected EGUs and the operating time must be expressed as ''stack operating hours'' (as defined in § 72.2 of this chapter).

(7) In accordance with § 60.13(g) of this chapter, if the exhaust gases from an affected EGU implementing the continuous emissions monitoring provisions in paragraph (a)(3)(i) of this section are emitted to the atmosphere through multiple stacks (or if the exhaust gases are routed to a common stack through multiple ducts and you elect to monitor in the ducts), then the hourly CO_2 mass emissions and the ''stack operating time'' (as defined in § 72.2 of this chapter) at each stack or duct must be monitored separately. In this case, the owner or operator of an affected EGU must determine compliance with an applicable emission standard by summing the CO_2 mass emissions measured at the individual stacks or ducts and dividing by the net energy output for the affected EGU.

(8) If two or more affected EGUs serve a common electric generator, then you must apportion the combined hourly net energy output to the individual affected EGUs according to the fraction of the total steam load contributed by each EGU. Alternatively, if the affected EGUs are identical, then you may apportion the combined hourly net electrical load to the individual EGUs according to the fraction of the total heat input contributed by each EGU.

(b) [Reserved]

§ 62.16545 May I bank CO_2 ERCs for future use or transfer?

(a) An ERC may be banked for future use or transfer in a compliance account or a general account in accordance with paragraph (b) of this section.

(b) Any ERC that is held in a compliance account or a general account will remain in such account unless and until the ERC is deducted or transferred under §§ 62.16530, 62.16535, 62.16550, or 62.16565.

§ 62.16550 How does the Administrator process account errors?

The Administrator may, at his or her sole discretion and on his or her own motion, correct any error in any ATCS account. Within 10 business days of making such correction, the Administrator will notify the authorized account representative for the account.

§ 62.16555 What are my reporting, notification and submission requirements?

You must prepare and submit reports according to paragraphs (a) through (g) of this section, as applicable.

(a)(1) You must meet all applicable reporting requirements and submit reports as required under subpart G of part 75 of this chapter and you must include the following information, as applicable in the quarterly reports:

(i) The percentage of valid operating hours in each quarter described § 62.16540(a)(2) (*i.e.,* the total number of valid operating hours) in that period divided by the total number of operating hours in that period, multiplied by 100 percent);

(ii) The hourly CO_2 mass emission rate values (tons/hr) and unit (or stack) operating times, (as monitored and reported according to part 75 of this chapter), for each valid operating hour in the compliance period;

(iii) The net electric output and the net energy output (P_{net}) values for each valid operating hour in the compliance period;

(iv) The calculated CO_2 mass emissions (lb) for each valid operating hour in the compliance period;

(v) The sum of the hourly net energy output values and the sum of the hourly CO_2 mass emissions values, for all of the valid operating hours in the compliance period;

(vi) ERC replacement generation (if any), properly justified (see paragraph (a)(1)(viii) of this section);

(vii) The calculated CO_2 mass emission rate for the compliance period (lb/net MWh); and

(viii) If the report covers the final quarter of a compliance period, then you must include the CO_2 emission standard (as identified in Table 1 of this subpart) with which your affected EGU must comply, your CO_2 emission rate calculated according to § 62.16420(c), and if an affected EGU is complying with an emission standard by using ERCs, then the designated representative must also include in the report a list of all unique ERC serial numbers retired in the compliance period, and, for each ERC, the date an ERC was surrendered and retired and eligible resource identification information sufficient to demonstrates that it meets the requirements of § 62.16435 and qualifies to be issued ERCs (including location, type of qualifying generation or savings, date commenced generating or saving, and date of generation or savings for which the ERC was issued).

(b) If any required monitoring system has not been provisionally certified by the applicable date on which emissions data reporting is required to begin under paragraph (a) of this section, then the maximum (or in some cases, minimum) potential value for the parameter measured by the monitoring system shall be reported until the required certification testing is successfully completed, in accordance with § 75.4(j) of this chapter, § 75.37(b) of this chapter, or section 2.4 of appendix D to part 75 of this chapter (as applicable). Operating hours in which CO_2 mass emission rates are calculated using maximum potential values are not ''valid operating hours'' (as defined in § 62.16540(a)), and shall not be used in the compliance determinations.

(c) The designated representative of each affected EGU at the facility must make all submissions required under the CO_2 Rate-based Trading Program, except as provided in § 62.16510. This requirement does not change, create an exemption from, or otherwise affect the responsible official submission requirements under a title V operating permit program in parts 70 and 71 of this chapter.

(d) You must submit all electronic reports required under paragraph (a) of this section using the Emissions Collection and Monitoring Plan System (ECMPS) Client Tool provided by the Clean Air Markets Division in the Office of Atmospheric Programs of EPA.

(e) For affected EGUs under this subpart that are not in the Acid Rain Program, you must also meet the reporting requirements and submit reports as required under subpart G of part 75 of this chapter, to the extent that those requirements and reports provide applicable data for the compliance demonstrations required under this subpart.

(f) If your affected EGU captures CO_2 to meet the applicable emission standard, then you must report in accordance with the requirements of part 98, subpart PP, of this chapter and either:

(1) Report in accordance with the requirements of part 98, subpart RR, of this chapter, if injection occurs on-site; or

(2) Transfer the captured CO_2 to an affected EGU or facility that reports in accordance with the requirements of part 98, subpart RR, of this chapter, if injection occurs off-site.

(g) You must prepare and submit notifications specified in § 75.61 of this chapter, as applicable to your affected EGUs.

§ 62.16560 What are my recordkeeping requirements?

(a) The owner or operator of each affected EGU must maintain the records, as described in paragraph (a)(1) of this section, for at least 5 years following the date of each compliance period, occurrence, measurement, maintenance, corrective action, report, or record.

(1) Unless otherwise provided, the owner or operator of an affected EGU must maintain the following records on site for at least 2 years after the date of each compliance period, compliance true-up period, occurrence, measurement, maintenance, corrective action, report, or record, whichever is latest, according to § 60.7 of this chapter. The owner or operator of an affected EGU may maintain the records off site and electronically for the remaining year(s). This period may be extended for cause, at any time before the end of 5 years, in writing by the Administrator.

(i) The certificate of representation under § 62.16500 for the designated representative for each affected EGU and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents must be retained on site at the affected EGU beyond such 5-year period until such certificate of representation and documents are superseded because of the submission of a new certificate of representation under § 62.16500 changing the designated representative.

(ii) All emissions monitoring information, in accordance with this subpart.

(iii) Copies of all reports, compliance certifications, documents, data files, calculations and methods, other submissions and all records made or required under, or to demonstrate compliance with an affected EGU's emission standard under § 62.16420 and any other requirements of the CO_2 Rate-based Trading Program.

(iv) Data that are required to be recorded by part 75, subpart F, of this chapter.

(v) Data with respect to any ERCs generated by the affected EGU or used by the affected EGU in its compliance demonstration including the information in paragraphs (a)(1)(v)(A) and (B) of this section.

(A) All documents related to any ERCs used in a compliance demonstration, including each eligibility application, EM&V plan, M&V report, and independent verifier verification report associated with the issuance of each specific ERC, and each regulatory approval and any documentation that supports the issuance of each ERC by the Administrator.

(B) All records and reports relating to the surrender and retirement of ERCs for compliance with this regulation, including the date each individual ERC with a unique serial identification number was surrendered and/or retired.

(2) [Reserved]

(b) [Reserved]

§ 62.16565 What actions may the Administrator take on submissions?

(a) The Administrator may review and conduct independent audits concerning any submission under the CO_2 Rate-based Trading Program and make appropriate adjustments of the information in the submission.

(b) The Administrator may deduct ERCs from or transfer ERCs to a compliance account, based on the information in a submission, as adjusted under paragraph (a) of this section, and record such deductions and transfers.

Definitions

§ 62.16570 What definitions apply to this subpart?

The terms used in this subpart have the meanings set forth in this section as follows:

Acid Rain Program means a multi-state SO_2 and NO_X air pollution control and emission reduction program established by the Administrator under title IV of the Clean Air Act and parts 72 through 78 of this chapter.

Administrator means the Administrator of the United States Environmental Protection Agency or his or her delegate, or the authorized state official under an approved state plan that incorporates this subpart.

Affected electric generating unit or *Affected EGU* means any steam generating unit, IGCC, or stationary combustion turbine that meets the applicability requirements in §§ 60.5840(b) and 60.5845 of this chapter. An affected EGU is not an eligible resource.

Allowable CO_2 emission rate means, for an affected EGU, the most stringent State or federal CO_2 emission rate limit (in lb/MWh or, if in lb/mmBtu, converted to lb/MWh by multiplying it by the affected EGU's heat rate in mmBtu/MWh) that is applicable to the affected EGU and covers the longest averaging period not exceeding 1 year.

Allowance system means a control program under which the owner or operator of each affected EGU is required to hold an authorization for each specified unit of carbon dioxide emitted from that facility during a specified period and which limits the total amount of such authorizations available to be held for carbon dioxide for a specified period and allows the transfer of such authorizations not used to meet the authorization-holding requirement.

Allowance Tracking and Compliance System (ATCS) means the system by which the Administrator records allocations, deductions, and transfers of ERCs under the CO_2 Rate-based Trading Program. Such allowances are allocated, recorded, held, deducted, or transferred only as whole ERCs.

Alternate designated representative means, for a CO_2 Rate-based Trading affected EGU and each affected EGU at the facility, the natural person who is authorized by the owners and operators of the affected EGU and all such affected EGUs at the affected EGU, in accordance with this subpart, to act on behalf of the designated representative in matters pertaining to the CO_2 Rate-based Trading Program. If the affected EGU is also subject to the Acid Rain Program, TR NO_X Annual Trading Program, TR NO_X Ozone Season Trading Program, TR SO_2 Group 1 Trading Program, or TR SO_2 Group 2 Trading Program, then this natural person shall be the same natural person as the alternate designated representative, as defined in the respective program.

Annual capacity factor means the ratio between the actual heat input to an EGU during a calendar year and the potential heat input to the EGU had it been operated for 8,760 hours during a calendar year at the base load rating. Also see capacity factor.

Authorized account representative means, for a general account, the natural person who is authorized, in accordance with this subpart, to transfer and otherwise dispose of ERCs held in the general account and, for a CO_2 Rate-based Trading Program affected EGU's, the designated representative of the affected EGU is the authorized account representative.

Automated data acquisition and handling system or *DAHS* means the component of the continuous emission monitoring system, or other emissions monitoring system approved for use under this subpart, designed to interpret and convert individual output signals from pollutant concentration monitors, flow monitors, diluent gas monitors, and other component parts of the monitoring system to produce a continuous record of the measured parameters in the measurement units required by this subpart.

Base load rating means the maximum amount of heat input (fuel) that an EGU can combust on a steady state basis, as determined by the physical design and characteristics of the EGU at ISO conditions. For a stationary combustion turbine, *base load rating* includes the heat input from duct burners.

Baseline means the electricity use that would have occurred without implementation of a specific EE measure.

Biomass means biologically based material that is living or dead (*e.g.,* trees, crops, grasses, tree litter, roots) above and belowground, and available on a renewable or recurring basis. Materials that are biologically based include non-fossilized, biodegradable organic material originating from modern or contemporarily grown plants, animals, or microorganisms (including plants, products, byproducts and residues from agriculture, forestry, and related activities and industries, as well as the non-fossilized and biodegradable organic fractions of industrial and municipal wastes, including gases and liquids recovered from the decomposition of non-fossilized and biodegradable organic material).

Boiler means an enclosed fossil- or other-fuel-fired combustion device used to produce heat and to transfer heat to recirculating water, steam, or other medium.

Business day means a day that does not fall on a weekend or a federal holiday.

Capacity factor means, as used for the output based set-aside, the ratio of the net electrical energy produced by a generating unit for the period of time considered to the electrical energy that could have been produced at continuous net summer capacity during the same period.

Certifying official means a natural person who is:

(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;

(2) For a partnership or sole proprietorship, a general partner or the proprietor respectively; or

(3) For a local government entity or State, federal, or other public agency, a principal executive officer or ranking elected official.

Clean Air Act means the Clean Air Act, 42 U.S.C. 7401, *et seq.*

CO_2 emissions limitation means the tonnage of CO_2 emissions authorized in a compliance period in a given year by the CO_2 allowances available for deduction for the affected EGU under § 62.16535(a) for such compliance period.

CO_2 Rate-Based Trading Program means a multi-state CO_2 air pollution control and emission reduction program established in accordance with this subpart and subpart UUUU of part 60 of this chapter (including such a program that is revised in a State plan or state allowance distribution methodology, or by the Administrator under subpart UUUU of part 60 of this chapter), as a means of controlling CO_2 emissions.

Coal means the definition as defined in subpart TTTT of part 60 of this chapter.

Combined cycle unit means an electric generating unit that uses a stationary combustion turbine from which the heat from the turbine exhaust gases is recovered by a heat recovery steam generating unit to generate additional electricity.

Combined heat and power unit or *CHP unit, (*also known as *''cogeneration''*) means an electric generating unit that uses a steam-generating unit or stationary combustion turbine to simultaneously produce both electric (or mechanical) and useful thermal output from the same primary energy affected EGU.

Common practice baseline or CPB means a baseline derived based on a default technology or condition that would have been in place at the time of implementation of an EE measure in the absence of the EE measure (for example, the standard or market-average or pre-existing equipment that a typical consumer/building owner would have continued to use or would have installed at the time of project implementation in a given circumstance, such as a given building type, EE program type or delivery mechanism, and geographic region).

Common stack means a single flue through which emissions from two or more units are exhausted.

Compliance account means an Allowance Transfer and Compliance System account, established by the Administrator for an affected EGU under this subpart, in which any ERC allocations to the affected EGUs at the affected EGU are recorded and in which are held any CO_2 allowances available for use for a compliance period in a given year in complying with the affected EGU's CO_2 emission standard in accordance with §§ 62.16420 and 62.16535.

Compliance period means the multi-year periods starting January 1 of the first calendar year of the period, except as provided in § 62.16420(c)(3), and ending on December 31 of the last calendar year, inclusive:

(1) Compliance Period 1 means the period of 3 calendar years from January 1, 2022 to December 31, 2024;

(2) Compliance Period 2 means the period of 3 calendar years from January 1, 2025 to December 31, 2027; and

(3) Compliance Period 3 means the period of 2 calendar years from January 1, 2028 to December 31, 2029.

Conservation voltage regulation (or reduction) (CVR) means an EE measure that produces electricity savings by reducing (or regulating) voltage at the electrical feeder level.

Continuous emission monitoring system or *CEMS* means the equipment required under this subpart to sample, analyze, measure, and provide, by means of readings recorded at least once every 15 minutes and using an automated data acquisition and handling system (DAHS), a permanent record of CO_2 emissions, stack gas volumetric flow rate, stack gas moisture content, and O_2 concentration (as applicable), in a manner consistent with part 75 of this chapter and § 62.16540(a)(3). The following systems are the principal types of continuous emission monitoring systems:

(1) A flow monitoring system, consisting of a stack flow rate monitor and an automated data acquisition and handling system and providing a permanent, continuous record of stack gas volumetric flow;

(2) A moisture monitoring system, as defined in § 75.11(b)(2) of this chapter and providing a permanent, continuous record of the stack gas moisture content, in percent H_2O;

(3) A CO_2 monitoring system, consisting of a CO_2 pollutant concentration monitor (or an O_2 monitor plus suitable mathematical equations from which the CO_2 concentration is derived) and an automated data acquisition and handling system and providing a permanent, continuous record of CO_2 emissions, in percent CO_2; and

(4) An O_2 monitoring system, consisting of an O_2 concentration monitor and an automated data acquisition and handling system and providing a permanent, continuous record of O_2, in percent O_2.

Control area operator means an electric system or systems, bounded by interconnection metering and telemetry, capable of controlling generation to maintain its interchange schedule with other control areas and contributing to frequency regulation of the interconnection.

Deemed savings means estimates of average annual electricity savings for a single unit of an installed demand-side EE measure that: has been developed from data sources (such as prior metering studies) and analytical methods widely considered acceptable for the measure; and is applicable to the situation and conditions in which the measure is implemented. Individual parameters or calculation methods also can be deemed, including EUL values. Common sources of deemed savings values are previous evaluations and studies that involved actual measurements and analyses. Deemed savings values are applicable for specific demand-side EE measures. A single deemed savings value may not be used for a program as a whole, nor for a multi-measure project, because of the degree of variation in how systems are used in different building types or market segments.

Demand-side energy efficiency or demand-side EE means an installed piece of equipment or system, a modification of existing equipment or system, or a strategy intended to affect consumer electricity-use behavior, that results in a reduction in electricity use (in MWh) at an end-use facility, premises, or equipment connected to the electricity grid. Demand-side EE is implemented through energy efficiency activities, projects, programs or measures

Derate means a decrease in the available capacity of an electric generating unit, due to a system or equipment modification or to discounting a portion of a generating unit's capacity for planning purposes.

Designated representative means, for a CO_2 Rate-based Trading affected EGU and each affected EGU at the affected EGU, the natural person who is authorized by the owners and operators of the affected EGU and all such affected EGUs at the affected EGU, in accordance with this subpart, to represent and legally bind each owner and operator in matters pertaining to the CO_2 Rate-based Trading Program. If the CO_2 Rate-based Trading affected EGU is also subject to the Acid Rain Program, TR NO_X Annual Trading Program, TR NO_X Ozone Season Trading Program, TR SO_2 Group 1 Trading Program, or TR SO_2 Group 2 Trading Program, then this natural person shall be the same natural person as the designated representative, as defined in the respective program.

Design efficiency means the rated overall net efficiency (*e.g.,* electric plus thermal output) on a higher heating value basis of the EGU at the base load rating and ISO conditions.

Distillate oil means the definition as defined in subpart TTTT of part 60 of this chapter.

Effective useful life (EUL) means the duration over which electricity savings from an EE measure occur, reported in years. EUL values are typically specific to individual EE projects but also may be specified by an EE program.

Electricity savings means the savings that results from a change in electricity use resulting from the implementation of demand-side EE.

Eligible resource means a resource that meets the requirements of § 62.16435 and has been registered with the EPA-administered ERC tracking system or an ERC tracking system approved in a State plan by the EPA. An eligible resource is not an affected EGU.

EM&V plan means an evaluation measurement and verification plan that meets the requirements of § 62.16455.

Emissions means air pollutants exhausted from an affected EGU into the atmosphere; emissions must be measured, recorded, and reported to the Administrator by the designated representative, and as modified by the Administrator:

(1) In accordance with this subpart; and

(2) With regard to a period before the affected EGU or facility is required to measure, record, and report such air pollutants in accordance with this subpart, in accordance with part 75 of this chapter.

Emission rate credit (ERC) means a tradable compliance instrument that meets the requirements of § 60.5790(c) of this chapter.

ERC deduction or *deduct ERCs* means the permanent withdrawal of ERCs by the Administrator from a compliance account (*e.g.,* in order to account for compliance with the applicable CO_2 emission standard).

Energy efficiency program or EE program means organized activities sponsored and funded by a particular entity to promote the adoption of one or more EE project or EE measure for the purpose of reducing electricity use.

Energy efficiency project or EE project means a combination of multiple technologies, energy-use practices or behaviors implemented at a single facility or premises for the purpose of reducing electricity use; EE projects may be implemented as part of an EE program or as an independent privately-funded action.

Energy efficiency measure or EE measure means a single technology, energy-use practice or behavior that, once implemented or adopted, reduces electricity use of a particular end-use, facility, or premises; EE measures may be implemented as part of an EE program or as an independent privately-funded action.

ERC held or *hold ERCs* means the ERCs treated as included in an ATCS account as of a specified point in time because at that time they:

(1) Have been recorded by the Administrator in the account or transferred into the account by a correctly submitted, but not yet recorded, ERC transfer in accordance with this subpart; and

(2) Have not been transferred out of the account by a correctly submitted, but not yet recorded, ERC transfer in accordance with this subpart.

ERC transfer deadline means, for a compliance period in a given year, midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after such compliance period and is the deadline by which an ERC transfer must be submitted for recordation in a affected EGU's compliance account in order to be available for use in complying with the affected EGU's CO_2 emission standard for such compliance period in accordance with §§ 62.16420 and 62.16535.

Essential generating characteristics means any characteristic that affects the eligibility of the qualifying energy generating resource for generating ERCs pursuant to this regulation, including the type of resource.

Excess emissions means any ton of emissions from the affected EGUs at an affected EGU during a compliance period that exceeds the CO_2 emissions limitation for the affected EGU for such compliance period.

Existing state program, requirement, or measure means, in the context of a State plan, a regulation, requirement, program, or measure administered by a state, utility, or other entity that is currently established. This may include a regulation or other legal requirement that includes past, current, and future obligations, or current programs and measures that are in place and are anticipated to be continued or expanded in the future, in accordance with established plans. An existing state program, requirement, or measure may have past, current, and future impacts on EGU CO_2 emissions.

Facility means all buildings, structures, or installations located in one or more contiguous or adjacent properties under common control of the same person or persons. This definition does not change or otherwise affect the definition of ''major source'', ''stationary source'', or ''source'' as set forth and implemented in a title V operating permit program or any other program under the Clean Air Act.

Final compliance period means a compliance period within the final period, each being 2 calendar years (with a calendar year beginning on January 1 and ending on December 31), and the first final compliance period beginning on January 1, 2030 and ending December 31, 2031.

Final period means the period that begins on January 1, 2030 and continues thereafter. The final period is comprised of final compliance periods, each of which is 2 calendar years (with a calendar year beginning on January 1 and ending on December 31).

Fossil fuel means the definition as defined in subpart TTTT of part 60 of this chapter.

Fossil-fuel-fired means, with regard to an affected EGU, combusting any amount of fossil fuel.

Gaseous fuel means the definition as defined in subpart TTTT of part 60 of this chapter.

General account means an ATCS account established under this subpart that is not a compliance account.

Generator means a device that produces electricity.

Gross electrical output means, for an affected EGU, electricity made available for use, including any such electricity used in the power production process (which process includes, but is not limited to, any on-site processing or treatment of fuel combusted at the affected EGU and any on-site emission controls).

GS–ERC means an ERC issued for net energy output MWh of gas shift to, but which may not be used for compliance by, an affected EGU that is a stationary combustion turbine. Aside from this restriction on use for compliance, GS–ERCs are subject to all other provisions of this subpart related to ERCs.

Heat input means, for an affected EGU for a specified period of time, the product (in mmBtu/time) of the gross calorific value of the fuel (in mmBtu/lb) fed into the affected EGU multiplied by the fuel feed rate (in lb of fuel/time), as measured, recorded, and reported to the Administrator by the designated representative and as modified by the Administrator in accordance with this subpart and excluding the heat derived from preheated combustion air, recirculated flue gases, or exhaust.

Heat input rate means, for an affected EGU, the amount of heat input (in mmBtu) divided by affected EGU operating time (in hr) or, for an affected EGU and a specific fuel, the amount of heat input attributed to the fuel (in mmBtu) divided by the affected EGU operating time (in hr) during which the affected EGU combusts the fuel.

Heat rate means, for an affected EGU, the affected EGU's maximum design heat input (in Btu/hr), divided by the product of 1,000,000 Btu/mmBtu and the affected EGU's maximum hourly load.

Heat recovery steam generating unit (HRSG) means a unit in which hot exhaust gases from the combustion turbine engine are routed in order to extract heat from the gases and generate useful output. Heat recovery steam generating units can be used with or without duct burners.

Indian country means ''Indian country'' as defined in 18 U.S.C. 1151.

Integrated gasification combined cycle facility or *IGCC facility* means a combined cycle facility that is designed to burn fuels containing 50 percent (by heat input) or more solid-derived fuel not meeting the definition of natural gas plus any integrated equipment that provides electricity or useful thermal output to either the affected facility or auxiliary equipment. The Administrator may waive the 50 percent solid-derived fuel requirement during periods of the gasification system construction, startup and commissioning, shutdown, or repair. No solid fuel is directly burned in the unit during operation.

Interim period means the period of 8 calendar years from January 1, 2022 to December 31, 2029. The interim period is comprised of three compliance periods, compliance period 1, compliance period 2, and compliance period 3.

ISO conditions means 288 Kelvin (15 °C), 60 percent relative humidity and 101.3 kilopascals pressure.

Liquid fuel means the definition as defined in subpart TTTT of part 60 of this chapter.

M&V report means a monitoring and verification report that meets the requirements of § 62.16460.

Maximum design heat input means, for an affected EGU, the maximum amount of fuel per hour (in Btu/hr) that the affected EGU is capable of combusting on a steady state basis as of the initial installation of the affected EGU as specified by the manufacturer of the affected EGU.

Mechanical output means the useful mechanical energy that is not used to operate the affected facility, generate electricity and/or thermal output, or to enhance the performance of the affected facility. Mechanical energy measured in horsepower hour should be converted into MWh by multiplying it by 745.7 then dividing by 1,000,000.

Monitoring system means any monitoring system that meets the requirements of this subpart, including a continuous emission monitoring system, an alternative monitoring system, or an excepted monitoring system under part 75 of this chapter.

Nameplate capacity means, starting from the initial installation of a generator, the maximum electrical generating output (in MWe, rounded to the nearest tenth) that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings) of such installation as specified by the manufacturer of the generator or, starting from the completion of any subsequent physical change in the generator resulting in an increase in the maximum electrical generating output that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings), such increased maximum amount (in MWe, rounded to the nearest tenth) of such completion as specified by the person conducting the physical change.

Natural gas means the definition as defined in subpart TTTT of part 60 of this chapter.

Net-electric output means the amount of gross generation the generator(s) produce (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)), as measured at the generator terminals, less the electricity used to operate the plant (*i.e.,* auxiliary loads); such uses include fuel handling equipment, pumps, fans, pollution control equipment, other electricity needs, and transformer losses as measured at the transmission side of the step up transformer (*e.g.,* the point of sale).

Net energy output means:

(1) The net electric or mechanical output from the affected facility, plus 100 percent of the useful thermal output measured relative to SATP conditions that is not used to generate additional electric or mechanical output or to enhance the performance of the affected EGU (*e.g.,* steam delivered to an industrial process for a heating application); and

(2) For combined heat and power facilities where at least 20.0 percent of the total net energy output consists of electric or direct mechanical output and at least 20.0 percent of the total net energy output consists of useful thermal output on a 12-operating month rolling average basis, the net electric or mechanical output from the affected EGU divided by 0.95, plus 100 percent of the useful thermal output (*e.g.,* steam delivered to an industrial process for a heating application).

Net summer capacity means the maximum output, commonly expressed in megawatts (MW), that generating equipment can supply to system load, as demonstrated by a multi-hour test, at the time of summer peak demand (period of June 1 through September 30.) This output reflects a reduction in capacity due to electricity use for station service or auxiliaries.

Operate or *operation* means, with regard to an affected EGU, to combust fuel.

Operator means, for a CO_2 Rate-based Trading affected EGU or an affected EGU at an affected EGU respectively, any person who operates, controls, or supervises an affected EGU at the affected EGU or the affected EGU and includes, but is not limited to, any holding company, utility system, or plant manager of such affected EGU or affected EGU.

Owner means, for a CO_2 Rate-based Trading affected EGU or an affected EGU at an affected EGU respectively, any of the following persons:

(1) Any holder of any portion of the legal or equitable title in an affected EGU at the affected EGU or the affected EGU;

(2) Any holder of a leasehold interest in an affected EGU at the affected EGU or the affected EGU, provided that, unless expressly provided for in a leasehold agreement, ''owner'' shall not include a passive lessor, or a person who has an equitable interest through such lessor, whose rental payments are not based (either directly or indirectly) on the revenues or income from such affected EGU; and

(3) Any purchaser of power from a affected EGU at the affected EGU or the affected EGU under a life-of-the-unit, firm power contractual arrangement.

Permanently retired means, with regard to an affected EGU, that an affected EGU is unavailable for service and the affected EGU's owners and operators: have taken on as enforceable obligations in the operating permit that covers the affected EGU the conditions of § 62.16415; or rescinded or otherwise terminated all permits required for construction or operation of the affected EGU under the Clean Air Act. Cessations in operations that do not meet this definition do not constitute permanent retirements.

Petroleum means the definition as defined in subpart TTTT of part 60 of this chapter.

Qualified biomass means a biomass feedstock that is demonstrated to qualify as a method to control increases of CO_2 levels in the atmosphere.

Random error means errors occurring by chance that may cause electricity savings values to be inconsistently overestimated or underestimated, and may result from a change in electricity use due to unaccounted-for factors that affect electricity use. The magnitude of random error can be quantified based on the variations observed across different units.

Receive or *receipt of* means, when referring to the Administrator, to come into possession of a document, information, or correspondence (whether sent in hard copy or by authorized electronic transmission), as indicated in an official log, or by a notation made on the document, information, or correspondence, by the Administrator in the regular course of business.

Recordation, record, or *recorded* means, with regard to ERCs, the moving of ERCs by the Administrator into, out of, or between ATCS accounts, for purposes of allocation, transfer, or deduction.

Reference method means any direct test method of sampling and analyzing for an air pollutant as specified in § 75.22 of this chapter.

Replacement, replace, or *replaced* means, with regard to an affected EGU, the demolishing of an affected EGU, or the permanent retirement and permanent disabling of an affected EGU, and the construction of another affected EGU (the replacement affected EGU) to be used instead of the demolished or retired affected EGU (the replaced affected EGU).

Solid fuel means the definition as defined in subpart TTTT of part 60 of this chapter.

Solid waste incineration unit means a stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine that is a ''solid waste incineration unit'' as defined in section 129(g)(1) of the Clean Air Act.

Standard ambient temperature and pressure (SATP) conditions means 298.15 Kelvin (25 °C, 77 °F) and 100.0 kilopascals (14.504 psi, 0.987 atm) pressure. The enthalpy of water at SATP conditions is 50 Btu/lb.

State agent means an entity acting on behalf of the State, with the legal authority of the State.

State measures means measures that the State adopts and implements as a matter of state law. Such measures are enforceable only per state law, and are not included in and codified as part of the federally enforceable State plan.

Stationary combustion turbine means all equipment, including but not limited to the turbine engine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), heat recovery system, fuel compressor, heater, and/or pump, post-combustion emissions control technology, and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any combined cycle combustion turbine, and any combined heat and power combustion turbine based system plus any integrated equipment that provides electricity or useful thermal output to the combustion turbine engine, heat recovery system or auxiliary equipment. Stationary means that the combustion turbine is not self-propelled or intended to be propelled while performing its function. It may, however, be mounted on a vehicle for portability. If a stationary combustion turbine burns any solid fuel directly then it is considered a steam generating unit.

Steam generating unit means any furnace, boiler, or other device used for combusting fuel and producing steam (nuclear steam generators are not included) plus any integrated equipment that provides electricity or useful thermal output to the affected facility or auxiliary equipment.

Submit or *serve* means to send or transmit a document, information, or correspondence to the person specified in accordance with the applicable regulation:

(1) In person;

(2) By United States Postal Service; or

(3) By other means of dispatch or transmission and delivery;

(4) Provided that compliance with any ''submission'' or ''service'' deadline shall be determined by the date of dispatch, transmission, or mailing and not the date of receipt.

Systematic error means inaccuracies in the same direction, causing electricity savings values to be consistently either overestimated or underestimated, and may result from factors such as incorrect assumptions, a methodological issue, or a flawed reporting system.

Transmission and distribution loss means the difference between the quantity of electricity that serves a load (measured at the busbar of the generator) and the actual electricity use at the final distribution location (measured at the on-site meter).

Transmission and distribution measures or T&D measures means EE measures intended to improve the efficiency of the electrical transmission and distribution system by decreasing electricity loses on the system.

Unit operating day means, with regard to an affected EGU, a calendar day in which the affected EGU combusts any fuel.

Unit operating hour or *hour of unit operation* means, with regard to an affected EGU, an hour in which the affected EGU combusts any fuel.

Uprate means an increase in available electric generating unit power capacity due to a system or equipment modification.

Useful thermal output means the thermal energy made available for use in any heating application (*e.g.,* steam delivered to an industrial process for a heating application, including thermal cooling applications) that is not used for electric generation, mechanical output at the affected EGU, to directly enhance the performance of the affected EGU (*e.g.,* economizer output is not useful thermal output, but thermal energy used to reduce fuel moisture is considered useful thermal output), or to supply energy to a pollution control device at the affected EGU. Useful thermal output for affected EGU(s) with no condensate return (or other thermal energy input to the affected EGU(s)) or where measuring the energy in the condensate (or other thermal energy input to the affected EGU(s)) would not meaningfully impact the emission rate calculation is measured against the energy in the thermal output at SATP conditions. Affected EGU(s) with meaningful energy in the condensate return (or other thermal energy input to the affected EGU) must measure the energy in the condensate and subtract that energy relative to SATP conditions from the measured thermal output.

Utility power distribution system means the portion of an electricity grid owned or operated by a utility and dedicated to delivering electricity to customers.

Valid data means quality-assured data generated by continuous monitoring systems that are installed, operated, and maintained according to part 75 of this chapter. For CEMS, the initial certification requirements in § 75.20 of this chapter and appendix A to part 75 of this chapter must be met before quality-assured data are reported under this subpart; for on-going quality assurance, the daily, quarterly, and semiannual/annual test requirements in sections 2.1, 2.2, and 2.3 of appendix B to part 75 of this chapter must be met and the data validation criteria in sections 2.1.5, 2.2.3, and 2.3.2 of appendix B to part 75 of this chapter apply. For fuel flow meters, the initial certification requirements in section 2.1.5 of appendix D to part 75 of this chapter must be met before quality-assured data are reported under this subpart (except for qualifying commercial billing meters under section 2.1.4.2 of appendix D), and for on-going quality assurance, the provisions in section 2.1.6 of appendix D to part 75 of this chapter apply (except for qualifying commercial billing meters).

Verification report means a report that meets the requirements of § 62.16465.

Waste-to-Energy means a process or unit (*e.g.,* solid waste incineration unit) that recovers energy from the conversion or combustion of waste stream materials, such as municipal solid waste, to generate electricity and/ or heat.

§ 62.16575 What measurements, abbreviations, and acronyms apply to this subpart?

The measurements, abbreviations, and acronyms used in this subpart are defined as follows:

ADR—alternated designated representative
Btu—British thermal unit
CPP—clean power plan
CO_2—carbon dioxide
COI—conflict of interest
CVR—conservative voltage regulation
DR—designated representative
EE—energy efficiency
EGU—electric generating unit
EM&V—evaluation, measurement, and verification
ERC—emission rate credit
GCV—gross calorific value
GJ—giga joule
H_2O—water
hr—hour
IGCC—integrated gasification combined cycle
kg—kilogram
kW—kilowatt electrical
kWh—kilowatt hour
lb—pound
M&V—measurement and verification
mmBtu—million Btu
MWe—megawatt electrical
MWh—megawatt hour
T&D—transmission and distribution
O_2—oxygen
PSD—prevention of significant deterioration
yr—year

TABLE 1 TO SUBPART NNN OF PART 62—CO_2 EMISSION STANDARDS (POUNDS OF CO_2 PER NET MWH)

Compliance period	Affected steam generating unit or integrated gasification combined cycle (IGCC) emission standards	Affected stationary combustion turbine emission standard
Compliance Period 1 (2022–2024)	1,671	877
Compliance Period 2 (2025–2027)	1,500	817
Compliance Period 3 (2028–2029)	1,380	784
Final Compliance Periods	1,305	771

TABLE 2 TO SUBPART NNN OF PART 62—INCREMENTAL GENERATION FACTOR FOR EMISSION RATE CREDITS (DIMENSIONLESS)

Compliance period	Incremental Generation Factor
Compliance Period 1 (2022–2024)	.22
Compliance Period 2 (2025–2027)	.32
Compliance Period 3 (2028–2029)	.28
Final Compliance Periods	.26

PART 78—APPEAL PROCEDURES

■ 6. The authority citation for Part 78 continues to read as follows:

Authority: 42 U.S.C. 7401, 7403, 7410, 7411, 7426, 7601, and 7651 *et seq.*

■ 7. Section 78.1 is amended by revising paragraph (a)(1) and adding paragraphs (b)(18) and (19) to read as follows:

§ 78.1 Purpose and scope.

(a)(1) This part shall govern appeals of any final decision of the Administrator under subparts MMM and NNN of part 62 of this chapter, part 72, 73, 74, 75, 76, or 77 of this chapter, subparts AA through II of part 96 of this chapter or State regulations approved under § 51.123(o)(1) or (2) of this chapter, subparts AAA through III of part 96 of this chapter or State regulations approved under § 51.124(o)(1) or (2) of this chapter, subparts AAAA through IIII of part 96 of this chapter or State regulations approved under § 51.123(aa)(1) or (2) of this chapter, part 97 of this chapter, or subpart RR of part 98 of this chapter; provided that matters listed in § 78.3(d) and preliminary, procedural, or intermediate decisions, such as draft Acid Rain permits, may not be appealed. All references in paragraph (b) of this section and in § 78.3 to subparts AA through II of part 96 of this chapter, subparts AAA through III of part 96 of this chapter, and subparts AAAA through IIII of part 96 of this chapter shall be read to include the comparable provisions in State regulations approved under § 51.123(o)(1) or (2) of this chapter, § 51.124(o)(1) or (2) of this chapter, and § 51.123(aa)(1) or (2) of this chapter, respectively.

* * * * *

(b) * * *

(18) Under subpart MMM of part 62 of this chapter,

(i) The decision on allocation of CO_2 allowances under § 62.16240 of this chapter.

(ii) The decision on allocation of CO_2 allowances from set-asides under § 62.16245 of this chapter.

(iii) The decision on the transfer of CO_2 allowances under § 62.16330 of this chapter.

(iv) The decision on the deduction of CO_2 allowances under § 62.16340 of this chapter.

(v) The correction of an error in an ATCS account under § 62.16355 of this chapter.

(vi) The adjustment of information in a submission and the decision on the deduction and transfer of CO_2 allowances based on the information as adjusted under § 62.16370 of this chapter.

(vii) The finalization of compliance period emissions data, including retroactive adjustment based on audit.

(19) Under subpart NNN of part 62 of this chapter,

(i) The decision on emission rate credit issuance, adjustment, and revocation under § 62.16435.

(ii) The decision on qualification status of eligible resources to receive emission rate credits under § 62.16460.

(iii) The decision on revocation of qualification status of an eligible resource under § 62.16440.

(iv) The decision on Adjustments for error or misstatement, suspension of ERC issuance under § 62.16450.

(v) The decision on accreditation of independent verifiers under § 62.16470.

(vi) The decision on revocation of accreditation status under § 62.16480.

(vii) The decision on the transfer of emission rate credits under § 62.16530 of this chapter.

(viii) The decision on the deduction of emission rate credits under § 62.16535 of this chapter.

(ix) The correction of an error in an ATCS account under § 62.16550 of this chapter.

(x) The adjustment of information in a submission and the decision on the deduction and transfer of emission rate credits based on the information as adjusted under § 62.16565 of this chapter.

(xi) The finalization of compliance period emissions data, including retroactive adjustment based on audit.

* * * * *

[FR Doc. 2015–22848 Filed 10–22–15; 8:45 am]

BILLING CODE 6560–50–P

FEDERAL REGISTER

Vol. 80 Friday,
No. 205 October 23, 2015

Part V

The President

Notice of October 21, 2015—Continuation of the National Emergency With Respect to the Situation in or in Relation to the Democratic Republic of the Congo

Federal Register

Vol. 80, No. 205

Friday, October 23, 2015

Presidential Documents

Title 3—

The President

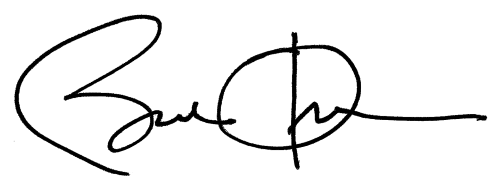
Notice of October 21, 2015

Continuation of the National Emergency With Respect to the Situation in or in Relation to the Democratic Republic of the Congo

On October 27, 2006, by Executive Order 13413, the President declared a national emergency with respect to the situation in or in relation to the Democratic Republic of the Congo and, pursuant to the International Emergency Economic Powers Act (50 U.S.C. 1701–1706), ordered related measures blocking the property of certain persons contributing to the conflict in that country. The President took this action to deal with the unusual and extraordinary threat to the foreign policy of the United States constituted by the situation in or in relation to the Democratic Republic of the Congo, which has been marked by widespread violence and atrocities that continue to threaten regional stability. I took additional steps pursuant to this national emergency in Executive Order 13671 of July 8, 2014.

This situation continues to pose an unusual and extraordinary threat to the foreign policy of the United States. For this reason, the national emergency declared in Executive Order 13413 of October 27, 2006, as amended by Executive Order 13671 of July 8, 2014, and the measures adopted to deal with that emergency, must continue in effect beyond October 27, 2015. Therefore, in accordance with section 202(d) of the National Emergencies Act (50 U.S.C. 1622(d)), I am continuing for 1 year the national emergency with respect to the situation in or in relation to the Democratic Republic of the Congo declared in Executive Order 13413, as amended by Executive Order 13671.

This notice shall be published in the *Federal Register* and transmitted to the Congress.



THE WHITE HOUSE,

October 21, 2015.

[FR Doc. 2015–27275

Filed 10–22–15; 11:15 am]

Billing code 3295–F6–P

Reader Aids

Federal Register

Vol. 80, No. 205

Friday, October 23, 2015

CUSTOMER SERVICE AND INFORMATION

Federal Register/Code of Federal Regulations	
General Information, indexes and other finding aids	**202–741–6000**
Laws	**741–6000**
Presidential Documents	
Executive orders and proclamations	**741–6000**
The United States Government Manual	**741–6000**
Other Services	
Electronic and on-line services (voice)	**741–6020**
Privacy Act Compilation	**741–6064**
Public Laws Update Service (numbers, dates, etc.)	**741–6043**

ELECTRONIC RESEARCH

World Wide Web

Full text of the daily Federal Register, CFR and other publications is located at: **www.fdsys.gov.**

Federal Register information and research tools, including Public Inspection List, indexes, and Code of Federal Regulations are located at: **www.ofr.gov.**

E-mail

FEDREGTOC-L (Federal Register Table of Contents LISTSERV) is an open e-mail service that provides subscribers with a digital form of the Federal Register Table of Contents. The digital form of the Federal Register Table of Contents includes HTML and PDF links to the full text of each document.

To join or leave, go to **http://listserv.access.gpo.gov** and select *Online mailing list archives, FEDREGTOC-L, Join or leave the list (or change settings);* then follow the instructions.

PENS (Public Law Electronic Notification Service) is an e-mail service that notifies subscribers of recently enacted laws.

To subscribe, go to **http://listserv.gsa.gov/archives/publaws-l.html** and select *Join or leave the list (or change settings);* then follow the instructions.

FEDREGTOC-L and **PENS** are mailing lists only. We cannot respond to specific inquiries.

Reference questions. Send questions and comments about the Federal Register system to: **fedreg.info@nara.gov**

The Federal Register staff cannot interpret specific documents or regulations.

CFR Checklist. Effective January 1, 2009, the CFR Checklist no longer appears in the Federal Register. This information can be found online at **http://bookstore.gpo.gov/.**

FEDERAL REGISTER PAGES AND DATE, OCTOBER

CFR PARTS AFFECTED DURING OCTOBER

At the end of each month the Office of the Federal Register publishes separately a List of CFR Sections Affected (LSA), which lists parts and sections affected by documents published since the revision date of each title.

361 ... 62443
600 ... 60275
1026 ... 59944
Proposed Rules:
Ch. I ... 60075
Ch. II ... 60075
Ch. III ... 60075
703 ... 63932

13 CFR

Proposed Rules:
107 ... 60077
115 ... 59667
120 ... 59667
121 ... 59667, 60300
123 ... 63715
125 ... 60300

14 CFR

Ch. I ... 60033, 63912
21 ... 59021, 61975
25 ... 60027, 60028, 60275
39 ... 59032, 59568, 59570, 60030, 60281, 60284, 60795, 61088, 61091, 61093, 61098, 61717, 61719, 61720, 61722, 61725, 63079, 63080, 63083, 63420, 63422, 64312, 64314
45 ... 59021
71 ... 59035, 59036, 60286, 60289, 60290, 62445, 62446, 62447, 62449, 62450, 62451, 63084, 63085, 63087, 63088, 63089, 63090, 63091, 63425, 63426, 64316, 64317, 64318
73 ... 60528, 61727
97 ... 61975, 61978, 62452, 62455
Proposed Rules:
39 ... 59081, 59672, 60303, 60307, 61131, 61133, 61327, 61330, 63132, 63134, 63136, 63141, 63145, 63147, 63151, 64371, 64373, 64375
71 ... 62509, 63473
73 ... 60573, 63153
93 ... 60310
147 ... 59674
1214 ... 63474

15 CFR

730 ... 61100
744 ... 60529, 61100
902 ... 59037, 60533
950 ... 63914
Proposed Rules:
774 ... 61137

16 CFR

4 ... 60797
1109 ... 61729
1500 ... 61729
Proposed Rules:
1109 ... 61773
1112 ... 63155, 63168
1130 ... 63155
1229 ... 63164
1232 ... 63155
1500 ... 61773

17 CFR

15 ... 59575
18 ... 59575
36 ... 59575
40 ... 59575
140 ... 59575
232 ... 59578
Proposed Rules:
201 ... 60082, 60091
210 ... 59083, 61332, 62274
270 ... 62274
274 ... 62274

18 CFR

11 ... 63667

19 CFR

4 ... 61278
7 ... 61278
10 ... 61278
12 ... 60292, 61278
18 ... 61278
19 ... 61278
24 ... 61278
54 ... 61278
102 ... 61278
113 ... 61278
123 ... 61278
125 ... 61278
128 ... 61278
132 ... 61278
134 ... 61278
141 ... 61278
142 ... 61278
143 ... 61278
144 ... 61278
145 ... 61278
146 ... 61278
148 ... 61278
151 ... 61278
152 ... 61278
158 ... 61278
163 ... 61278
174 ... 61278
181 ... 61278
191 ... 61278

20 CFR

404 ... 63092
416 ... 63092
422 ... 61733
655 ... 62958
Proposed Rules:
404 ... 63717
416 ... 63717

21 CFR

107 ... 61293
510 ... 61293
520 ... 61293
522 ... 61293
524 ... 61293
556 ... 61293
558 ... 61293, 61298
870 ... 63671
890 ... 61298
Proposed Rules:
101 ... 63477
880 ... 60809

22 CFR

11 ... 64319
Proposed Rules:
21 ... 61138

23 CFR

625 ... 61302

24 CFR

203 ... 61980
Proposed Rules:
60 ... 59092
100 ... 63720
203 ... 62510
291 ... 59690

25 CFR

81 ... 63094
82 ... 63094

26 CFR

1 ... 60293, 61308
Proposed Rules:
1 ... 61332, 64378
20 ... 64378
25 ... 64378
26 ... 64378
31 ... 64378
301 ... 64378

27 CFR

555 ... 59580

28 CFR

2 ... 63115

29 CFR

20 ... 60797
1625 ... 60539
1910 ... 60033
1926 ... 60033
4022 ... 61981

30 CFR

917 ... 63117
935 ... 63120
938 ... 63125
Proposed Rules:
901 ... 60107
946 ... 63933

31 CFR

Proposed Rules:
1010 ... 60575

32 CFR

236 ... 59581
1701 ... 63427
Proposed Rules:
188 ... 61997

33 CFR

100 ... 63674, 63676, 63916
117 ... 60293, 60294, 61750, 62456, 62457, 63428, 63674, 63676, 63677, 63918, 63919, 64324
147 ... 63674, 63676
165 ... 59049, 60802, 60803, 61309, 61983, 63674, 63676, 63678, 63919, 63921, 63923, 63926

34 CFR

Proposed Rules:
Ch. VI ... 63478

36 CFR

13 ... 64325

37 CFR

380 ... 59588

38 CFR

Proposed Rules:
17 ... 63480

39 CFR

Proposed Rules:
3050 ... 63482

40 CFR

9 ... 59593, 64064
30 ... 61087
31 ... 61087
33 ... 61087
35 ... 61087
40 ... 61087
45 ... 61087
46 ... 61087
47 ... 61087
52 ... 59052, 59055, 59610, 59611, 59615, 59620, 59624, 60040, 60043, 60045, 60047, 60049, 60295, 60540, 60541, 60805, 61101, 61107, 61109, 61111, 61112, 61311, 61751, 61752, 62457, 63429, 63431, 63436, 63451, 64344, 64346
60 ... 64510, 64662
63 ... 62390
70 ... 64510
71 ... 64510
81 ... 59624, 60049
82 ... 61985
98 ... 64262, 64510
122 ... 64064
123 ... 64064
124 ... 64064
127 ... 64064
180 ... 59627, 60545, 61118, 61122, 61125, 62462, 63680, 63683, 63686
228 ... 61757
261 ... 60052
271 ... 63691
403 ... 64064
501 ... 64064
503 ... 64064
721 ... 59593
Proposed Rules:
Ch. I ... 60577, 60584
51 ... 61139
52 ... 59094, 59695, 59703, 59704, 60108, 60109, 60110, 60314, 60318, 60576, 61140, 61141, 61774, 61775, 62003, 62511, 63185, 63483, 63640, 64160, 64381
56 ... 63935
60 ... 61139, 64966
61 ... 61139
62 ... 64966
63 ... 61139
70 ... 60110
78 ... 64966
81 ... 61775, 63640
180 ... 63731
260 ... 63284
261 ... 63284
262 ... 63284
263 ... 63284
264 ... 63284
265 ... 63284
266 ... 63284
267 ... 63284
271 ... 63284, 63734
273 ... 63284
372 ... 60818

41 CFR

Proposed Rules:
102–117 ... 59094

LIST OF PUBLIC LAWS

Note: No public bills which have become law were received by the Office of the Federal Register for inclusion in today's **List of Public Laws**.

Last List October 22, 2015

Public Laws Electronic Notification Service (PENS)

PENS is a free electronic mail notification service of newly enacted public laws. To subscribe, go to *http://listserv.gsa.gov/archives/publaws-l.html*

Note: This service is strictly for E-mail notification of new laws. The text of laws is not available through this service. **PENS** cannot respond to specific inquiries sent to this address.