TITLE 45
LEGISLATIVE RULE
DEPARTMENT OF ENVIRONMENTAL PROTECTION
AIR QUALITY

SERIES 16
STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

§45-16-1. General.

1.1. Scope. -- This rule establishes and adopts standards of performance for new stationary sources promulgated by the United States Environmental Protection Agency pursuant to section 111(b) of the federal Clean Air Act, as amended. This rule codifies general procedures and criteria to implement the standards of performance for new stationary sources set forth in 40 C.F.R. part 60. The Secretary hereby adopts these standards by reference. The Secretary also adopts associated reference methods, performance specifications and other test methods which are appended to these standards.

1.2. Authority. -- W.Va. Code § 22-5-4.

1.3. Filing date. -- ~~April 28, 2021~~.

1.4. Effective date. -- ~~June 1, 2021~~.

1.5. Sunset provision. -- Does not apply.

1.6. Incorporation by reference. -- federal counterpart regulation. The Secretary has determined that a federal counterpart rule exists, and in accordance with the Secretary's recommendation, with limited exception, this rule incorporates by reference 40 C.F.R. parts 60 and 65, to the extent referenced in 40 C.F.R. part 60, effective June 1, ~~2020~~2021.

§45-16-2. Definitions.

2.1. "Administrator" means the Administrator of the United States Environmental Protection Agency or his or her authorized representative.

2.2. "Clean Air Act" ("CAA") means the federal Clean Air Act, as amended, 42 U.S.C. § 7401, et seq.

2.3. "Secretary" means the Secretary of the Department of Environmental Protection or other person to whom the Secretary has delegated authority or duties pursuant to W.Va. Code §§ 22-1-6 or 22-1-8.

2.4. Other words and phrases used in this rule, unless otherwise indicated, shall have the meaning ascribed to them in 40 C.F.R. part 60. Words and phrases not defined therein shall have the meaning given to them in the federal Clean Air Act.

§45-16-3. Requirements.

3.1. No person may construct, reconstruct, modify, or operate or cause to be constructed, reconstructed, modified, or operated any source subject to the provisions of 40 C.F.R. part 60 which results or will result in a violation of this rule.

§45-16-4. Adoption of standards.

4.1. Standards. -- The Secretary hereby adopts and incorporates by reference the provisions of 40 C.F.R. parts 60 and 65, to the extent referenced in 40 C.F.R. part 60, including any reference methods, performance specifications and other test methods which are appended to these standards and contained in 40 C.F.R. parts 60 and 65, effective June 1, ~~2020~~2021, for the purposes of implementing a program for standards of performance for new stationary sources, except as follows:

4.1.a. 40 C.F.R. § 60.9 is amended to provide that information shall be available to the public in accordance with W.Va. Code §§ 22-5-1 et seq., 29B-1-1 et seq., and 45CSR31; and

4.1.b. Subparts B, C, Ca, Cb, Cc, Cd, Ce, Cf, Ea, Eb, Ec, WWW, XXX, AAAA, BBBB, CCCC, DDDD, EEEE, FFFF, LLLL and MMMM of 40 C.F.R. part 60 shall be excluded.

4.1.c. The following subparts of 40 C.F.R. part 60 relating to wood-burning heaters and appliances are expressly excluded and are not adopted or incorporated by reference in this rule:

4.1.c.1. Subpart AAA; and

4.1.c.2. Subpart QQQQ.

§45-16-5. Secretary.

5.1. Any and all references in 40 C.F.R. parts 60 and 65 to the "Administrator" are amended to be the "Secretary" except as follows:

5.1.a. Where the federal regulations specifically provide that the Administrator shall retain authority and not transfer authority to the Secretary;

5.1.b. Where provisions occur which refer to:

5.1.b.1. Alternate means of emission limitations;

5.1.b.2. Alternate control technologies;

5.1.b.3. Innovative technology waivers;

5.1.b.4. Alternate test methods;

5.1.b.5. Alternate monitoring methods;

5.1.b.6. Waivers/adjustments to recordkeeping and reporting;

5.1.b.7. Emissions averaging;

5.1.b.8. Applicability determinations; or

5.1.b.9. The authority to require testing under Section 114 of the Clean Air Act, as amended; or

5.1.c. Where the context of the regulation clearly requires otherwise.

§45-16-6. Permits.

6.1. Nothing contained in this adoption by reference shall be construed or inferred to mean that permit requirements in accordance with applicable rules shall be in any way be limited or inapplicable.

§45-16-7. Inconsistency between rules.

7.1. In the event of any inconsistency between this rule and any other rule of the Division of Air Quality, the inconsistency shall be resolved by the determination of the Secretary and the determination shall be based upon the application of the more stringent provision, term, condition, method or rule.

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 60, 63, 79, 80, 1042, 1043, 1065 and 1090

[EPA–HQ–OAR–2018–0227; FRL–10014–97–OAR]

RIN 2060–AT31

Fuels Regulatory Streamlining

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This action updates many of EPA's existing gasoline, diesel, and other fuel quality programs to improve overall compliance assurance and maintain environmental performance, while reducing compliance costs for industry and EPA. EPA is streamlining existing fuel quality regulations by removing expired provisions, eliminating redundant compliance provisions (*e.g.,* duplicative registration requirements that are required by every EPA fuels program), removing unnecessary and out-of-date requirements, and replacing them with a single set of provisions and definitions that applies to all gasoline, diesel, and other fuel quality programs. This action does not change the stringency of the existing fuel quality standards.

DATES: This rule is effective on January 1, 2021, except for amendatory instructions 48, 51, and 52, which are effective on December 4, 2020, and amendatory instructions 16, 18, and 19, which are effective on January 1, 2022. The incorporation by reference of certain publications listed in this regulation is approved by the Director of the Federal Register as of December 4, 2020. The incorporation by reference of ASTM D86–12, D93–13, D445–12, D613–13, D4052–11, and D5186–03 (R2009) in part 1065 was approved by the Director of the Federal Register as of June 27, 2014.

ADDRESSES: EPA has established a docket for this action under Docket ID No. EPA–HQ–OAR–2018–0227. All documents in the docket are listed on the *https://www.regulations.gov* website. 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 is not available on the internet and will be publicly available only in hard copy form. Publicly available docket materials are available electronically through *https://www.regulations.gov.*

FOR FURTHER INFORMATION CONTACT: Nick Parsons, Office of Transportation and Air Quality, Assessment and Standards Division, Environmental Protection Agency, 2000 Traverwood Drive, Ann Arbor, MI 48105; telephone number: 734–214–4479; email address: *parsons.nick@epa.gov.*

SUPPLEMENTARY INFORMATION:

Does this action apply to me?

Entities potentially affected by this final rule are those involved with the production, distribution, and sale of transportation fuels, including gasoline and diesel fuel. Potentially affected categories include:

Category	NAICS [1] code	Examples of potentially affected entities
Industry	211130	Natural gas liquids extraction and fractionation.
Industry	221210	Natural gas production and distribution.
Industry	324110	Petroleum refineries (including importers).
Industry	325110	Butane and pentane manufacturers.
Industry	325193	Ethyl alcohol manufacturing.
Industry	325199	Manufacturers of gasoline additives.
Industry	424710	Petroleum bulk stations and terminals.
Industry	424720	Petroleum and petroleum products wholesalers.
Industry	447110, 447190	Fuel retailers.
Industry	454310	Other fuel dealers.
Industry	486910	Natural gas liquids pipelines, refined petroleum products pipelines.
Industry	493190	Other warehousing and storage—bulk petroleum storage.

[1] North American Industry Classification System (NAICS).

This table is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be affected by this action. This table lists the types of entities that EPA is now aware could potentially be affected by this action. Other types of entities not listed in the table could also be affected. To determine whether your entity would be affected by this action, you should carefully examine the applicability criteria in 40 CFR part 1090. If you have any questions regarding the applicability of this action to a particular entity, consult the person listed in the **FOR FURTHER INFORMATION CONTACT** section.

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

EPA believes that this action does not have disproportionately high and adverse human health or environmental effects on minority populations, low income populations, and/or indigenous peoples, as specified in Executive Order 12898 (59 FR 7629, February 16, 1994). This action does not affect the level of protection provided to human health or the environment by applicable air quality standards. This action does not relax the control measures on sources regulated by EPA's fuel quality regulations and therefore will not cause emissions increases from these sources.

L. Congressional Review Act (CRA)

This action is subject to the CRA, and 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).

XVI. Statutory Authority

Statutory authority for this action comes from sections 202, 203–209, 211, 213, 216, and 301 of the Clean Air Act, 42 U.S.C. 7414, 7521, 7522–7525, 7541, 7542, 7543, 7545, 7547, 7550, and 7601 as well as Public Law 109–58. Additional support for the procedural and compliance related aspects of this action comes from sections 114, 208, and 301(a) of the Clean Air Act, 42 U.S.C. 7414, 7521, 7542, and 7601(a).

List of Subjects

40 CFR Parts 60, 63, 1042, and 1043

Administrative practice and procedure, Air pollution control.

40 CFR Part 79

Fuel additives, Gasoline, Motor vehicle pollution, Penalties, Reporting and recordkeeping requirements.

40 CFR Part 80

Environmental protection, Administrative practice and procedure, Air pollution control, Diesel fuel, Fuel additives, Gasoline, Imports, Oil imports, Petroleum, Renewable fuel.

40 CFR Part 1065

Administrative practice and procedure, Air pollution control, Incorporation by reference.

40 CFR Part 1090

Environmental protection, Administrative practice and procedure, Air pollution control, Diesel fuel, Fuel additives, Gasoline, Imports, Incorporation by reference, Oil imports, Petroleum, Renewable fuel.

Dated: October 15, 2020.

Andrew Wheeler,

Administrator.

For the reasons set forth in the preamble, EPA amends 40 CFR parts 60, 63, 79, 80, 1042, 1043, and 1065 and adds 40 CFR part 1090 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.*

Subpart IIII—Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

■ 2. Amend § 60.4207 by:

■ a. Removing and reserving paragraph (a);

■ b. In paragraph (b), removing ''40 CFR 80.510(b)'' and adding ''40 CFR 1090.305'' in its place; and

■ c. Revising paragraph (d).

The revision reads as follows:

§ 60.4207 What fuel requirements must I meet if I am an owner or operator of a stationary CI internal combustion engine subject to this subpart?

* * * * *

(d) Beginning June 1, 2012, owners and operators of stationary CI ICE subject to this subpart with a displacement of greater than or equal to 30 liters per cylinder must use diesel fuel that meets a maximum per-gallon sulfur content of 1,000 parts per million (ppm).

* * * * *

Subpart JJJJ—Standards of Performance for Stationary Spark Ignition Internal Combustion Engines

§ 60.4235 [Amended]

■ 3. Amend § 60.4235 by removing ''40 CFR 80.195'' and adding ''40 CFR 1090.205'' in its place.

PART 63—NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES

■ 4. The authority citation for part 63 continues to read as follows:

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

Subpart R—National Emission Standards for Gasoline Distribution Facilities (Bulk Gasoline Terminals and Pipeline Breakout Stations)

■ 5. Amend § 63.421 by revising the definitions for ''Oxygenated gasoline'' and ''Reformulated gasoline'' to read as follows:

§ 63.421 Definitions.

* * * * *

Oxygenated gasoline means the same as defined in 40 CFR 80.2.

* * * * *

Reformulated gasoline means the same as defined in 40 CFR 80.2.

* * * * *

Subpart ZZZZ—National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

§ 63.6604 [Amended]

■ 6. In § 63.6604, amend paragraphs (a), (b), and (c) by removing ''40 CFR 80.510(b)'' and adding ''40 CFR 1090.305'' in its place.

PART 79—REGISTRATION OF FUEL AND FUEL ADDITIVES

■ 7. The authority citation for part 79 continues to read as follows:

Authority: 42 U.S.C. 7414, 7524, 7545, and 7601.

Subpart A—General Provisions

■ 8. Amend § 79.5 by revising paragraph (a)(1) to read as follows:

§ 79.5 Periodic reporting requirements.

(a) * * * (1) For each calendar year (January 1 through December 31) commencing after the date prescribed for any fuel in subpart D of this part, fuel manufacturers must submit to the Administrator a report for each registered fuel showing the range of concentration of each additive reported under § 79.11(a) and the volume of such fuel produced in the year. Reports must be submitted by March 31 for the preceding year, or part thereof, on forms supplied by the Administrator. If the date prescribed for a particular fuel in subpart D of this part, or the later registration of a fuel is between October 1 and December 31, no report will be required for the period to the end of that year.

* * * * *

Subpart C—Additive Registration Procedures

■ 9. Amend § 79.21 by:

■ a. Revising paragraphs (f) and (g); and

TABLE 2—EPA-APPROVED ARIZONA REGULATIONS

State citation	Title/subject	State effective date	EPA approval date	Additional explanation
* * * * * * *				
Article 13 (State Implementation Plan Rules For Specific Locations)				
* * * * * * *				
R18–2–B1302	Limits on SO_2 from the Hayden Smelter.	July 1, 2018.	[Insert ***Federal Register*** Citation], November 5, 2020.	Submitted on April 6, 2017. EPA issued a limited approval and limited disapproval of Rule R18–2–B1302.
* * * * * * *				

* * * * *

[FR Doc. 2020–23031 Filed 11–4–20; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 60 and 63

[EPA–HQ–OAR–2014–0741; FRL–10015–72–OAR]

RIN 2060–AU53

National Emission Standards for Hazardous Air Pollutants for Chemical Recovery Combustion Sources at Kraft, Soda, Sulfite, and Stand-Alone Semichemical Pulp Mills; Standards of Performance for Kraft Pulp Mill Affected Sources for Which Construction, Reconstruction, or Modification Commenced After May 23, 2013

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: The U.S. Environmental Protection Agency (EPA) is finalizing amendments to the National Emission Standards for Hazardous Air Pollutants (NESHAP) for Chemical Recovery Combustion Sources at Kraft, Soda, Sulfite, and Stand-alone Semichemical Pulp Mills, and the New Source Performance Standards (NSPS) for Kraft Pulp Mills constructed, reconstructed, or modified after May 23, 2013. The final rule clarifies how to set operating limits for smelt dissolving tank (SDT) scrubbers used at these mills and corrects cross-reference errors in both rules.

DATES: This final rule is effective on November 5, 2020.

ADDRESSES: The EPA has established a docket for this action under Docket ID No. EPA–HQ–OAR–2014–0741. All documents in the docket are listed on the *https://www.regulations.gov/* website. Although listed, some information is not publicly available, *e.g.,* Confidential Business Information or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the internet and will be publicly available only in hard copy form. Publicly available docket materials are available electronically through *https://www.regulations.gov/.* Out of an abundance of caution for members of the public and our staff, the EPA Docket Center and Reading Room are closed to the public, with limited exceptions, to reduce the risk of transmitting COVID–19. Our Docket Center staff will continue to provide remote customer service via email, phone, and webform.

FOR FURTHER INFORMATION CONTACT: For questions about this final action, contact Dr. Kelley Spence, Sector Policies and Programs Division (E143–03), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711; telephone number: (919) 541–3158; fax number: (919) 541–0516; and email address: *spence.kelley@epa.gov.*

SUPPLEMENTARY INFORMATION:

Preamble acronyms and abbreviations. We use multiple acronyms and terms in this preamble. While this list may not be exhaustive, to ease the reading of this preamble and for reference purposes, the EPA defines the following terms and acronyms here:

ADI Applicability Determination Index
CAA Clean Air Act
CFR Code of Federal Regulations
CRA Congressional Review Act
EPA U.S. Environnemental Protection Agency
ESP electrostatic precipitator
HAP hazardous air pollutant(s)
NAICS North American Industry Classification System
NESHAP national emission standards for hazardous air pollutants
NSPS new source performance standards
NTTAA National Technology Transfer and Advancement Act
OMB Office of Management and Budget
PFLA percent full load amperage
PM particulate matter
PRA Paperwork Reduction Act
RFA Regulatory Flexibility Act
RPM revolutions per minute
SDT smelt dissolving tank
UMRA Unfunded Mandates Reform Act

Background information. On October 31, 2019, the EPA proposed revisions to the NESHAP for Chemical Recovery Combustion Sources at Kraft, Soda, Sulfite, and Stand-Alone Semichemical Pulp Mills (40 CFR part 63, subpart MM) and the NSPS for Kraft Pulp Mills Constructed, Reconstructed, or Modified After May 23, 2013 (40 CFR part 60, subpart BBa) clarifying how to set operating limits for SDT scrubbers used at these mills and correcting cross-reference errors in both rules. The rules have similar requirements for setting operating limits for SDT scrubbers, therefore, similar revisions were proposed for both rules. See 84 FR 58356. In this action, the EPA is finalizing the proposed revisions with minor edits. The preamble includes a summary of the comments the EPA received and our responses resulting in improvements to the proposed rule. A summary of all public comments on the proposal and the EPA's specific responses to those comments is provided in the memorandum, ''*Response to Comments to Proposed Rule Amending 40 CFR part 63 Subpart MM and 40 CFR part 60 Subpart BBa,*'' included in the docket for this action. Redline versions of the regulatory language for 40 CFR part 63, subpart MM, and 40 CFR part 60, subpart BBa showing the final amendments resulting from this action and are also available in the docket.

Organization of this document. The information in this preamble is organized as follows:

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J. National Technology Transfer and Advancement Act (NTTAA)
K. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations
L. Congressional Review Act (CRA)

I. General Information

A. Does this action apply to me?

Table 1 of this preamble lists the NESHAP, NSPS, and associated regulated industrial source categories that are the subject of this final rule. Table 1 is not intended to be exhaustive, but rather provides a guide for readers regarding the entities that this final action is likely to affect. The final amendments, once promulgated, will be directly applicable to the affected sources. Federal, state, local, and tribal government entities will not be affected by this action. As defined in the *Initial List of Categories of Sources Under Section 112(c)(1) of the Clean Air Act Amendments of 1990* (see 57 FR 31576, July 16, 1992) and *Documentation for Developing the Initial Source Category List, Final Report* (see EPA–450/3–91–030, July 1992), the Pulp and Paper Production source category is any facility engaged in the production of pulp and/or paper. This category includes, but is not limited to, integrated mills (where pulp alone or pulp and paper or paperboard are manufactured on-site), non-integrated mills (where paper or paperboard are manufactured, but no pulp is manufactured on-site), and secondary fiber mills (where waste paper is used as the primary raw material). Examples of pulping methods include kraft, soda, sulfite, semi-chemical, and mechanical. The pulp and paper production process units include operations such as pulping, bleaching, and chemical recovery. A kraft pulp mill is defined as a facility engaged in kraft pulping and includes digester systems, brown stock washer systems, multiple-effect evaporator systems, condensate stripper systems, recovery furnaces, SDTs, and lime kilns.

TABLE 1—REGULATIONS AND INDUSTRIAL SOURCE CATEGORIES AFFECTED BY THIS FINAL ACTION

Source category	Name of action	NAICS [1] code
Pulp and Paper Production.	Chemical Recovery Combustion Sources at Kraft, Soda, Sulfite, and Stand-Alone Semichemical Pulp Mills (40 CFR part 63, subpart MM).	32211, 32212, 32213
Kraft Pulp Mills	Standards of Performance for Kraft Pulp Mill Affected Sources for Which Construction, Reconstruction, or Modification Commenced After May 23, 2013 (40 CFR part 60, subpart BBa).	322110

[1] North American Industry Classification System.

B. Where can I get a copy of this document and other related information?

In addition to being available in the docket, an electronic copy of this action is available on the internet. Following signature by the EPA Administrator, the EPA will post a copy of the action at *https://www.epa.gov/stationary-sources-air-pollution/kraft-soda-sulfite-and-stand-alone-semichemical-pulp-mills-mact-ii* and *https://www.epa.gov/stationary-sources-air-pollution/kraft-pulp-mills-new-source-performance-standards-nsps-40-cfr-60.* Following publication in the **Federal Register**, the EPA will post the **Federal Register** version of the final rule at this same website.

C. Judicial Review and Administrative Reconsideration

Under Clean Air Act (CAA) section 307(b)(1), judicial review of this action is available only by filing a petition for review in the United States Court of Appeals for the District of Columbia Circuit (the court) by January 4, 2021. Under CAA section 307(b)(2), the requirements established by this final rule may not be challenged separately in any civil or criminal proceedings brought by the EPA to enforce the requirements.

Section 307(d)(7)(B) of the CAA further provides that only an objection to a rule or procedure which was raised with reasonable specificity during the period for public comment (including any public hearing) may be raised during judicial review. This section also provides a mechanism for the EPA to reconsider the rule if the person raising an objection can demonstrate to the Administrator that it was impracticable to raise such objection within the period for public comment or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule. Any person seeking to make such a demonstration should submit a Petition for Reconsideration to the Office of the Administrator, U.S. Environmental Protection Agency, Room 3000, WJC South 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. Environmental Protection Agency, 1200 Pennsylvania Ave. NW, Washington, DC 20460.

II. Final Amendments

With this action, the EPA is finalizing amendments to the NESHAP for Chemical Recovery Combustion Sources at Kraft, Soda, Sulfite, and Stand-Alone Semichemical Pulp Mills (referred to hereafter as ''the NESHAP'') and the NSPS for Kraft Pulp Mills constructed, reconstructed, or modified after May 23, 2013 (referred to hereafter as ''the NSPS''). The amendments (referred to hereafter as the ''2019 proposed amendments'') were proposed on October 31, 2019 (84 FR 58356) to clarify how to set operating limits for SDT scrubbers used at these mills and correct cross-reference errors in both rules. As explained in this section, clarification was needed to address parameter monitoring issues that arose during implementation of the 2017 amendments to the NESHAP (referred to hereafter as the ''2017 NESHAP amendments'') as a result of the Agency's residual risk and technology review. See 82 FR 47328, October 11, 2017.

A. What are the final amendments to the NESHAP?

1. Alternative To Monitoring Pressure Drop for Certain SDT Scrubbers

The 2017 NESHAP amendments added fan amperage [1] to 40 CFR 63.864(e)(10)(iii) as an alternative to monitoring pressure drop for SDT dynamic scrubbers that operate at ambient pressure and low-energy entrainment scrubbers where the fan speed does not vary. Fan amperage was added as an alternative monitoring parameter based on the EPA's review of alternative monitoring requests for these types of SDT scrubbers available in the EPA's Applicability Determination Index (ADI) (81 FR 97074, December 30, 2016). In these previously approved alternative monitoring requests, the EPA acknowledged that pressure drop is not the best indicator of particulate matter (PM)/hazardous air pollutant (HAP) control device performance when the SDT scrubber is a low-energy entrainment scrubber or a dynamic scrubber that operates near atmospheric pressure. Low-energy entrainment scrubbers use the rotation of the fan blade to shatter the scrubbing liquid into fine droplets, while at the same time accelerating the particles into the airstream. The PM removal efficiency of these scrubbers is a function of the number of liquid droplets produced (to create a large contacting surface area) and the velocity of the PM imparted by the fan blade, which in turn, are functions of the amount of scrubbing liquid introduced and the tip speed of the fan blade. Therefore, the most important parameters to continuously monitor are the scrubbing liquid flow rate and the fan rotational speed (as indicated by the amperage of the fan motor or revolutions per minute (RPM)).

In addition to adding fan amperage as a monitoring parameter, the 2017 NESHAP amendments also specified a method in 40 CFR 63.864(j)(5)(i)(A) for setting the fan motor amperage operating limit, requiring that the minimum fan amperage operating limit be set as the lowest of the 1-hour average fan amperage values associated with each run demonstrating compliance with the applicable emission limit. The intent of establishing the operating limit as the lowest 1-hour average fan amperage was to demonstrate that the scrubber was operating as intended and removing HAP accordingly, because fan amperage values can be correlated with fan speed. This seemed reasonable during the development of the 2017 NESHAP amendments because the fans on these units are constant speed fans and changes in the load to the fan motor (*e.g.,* changes in gas density/pressure or fan belt issues) result in changes in the amperage needed to maintain the constant speed. For example, a scrubber operating without any scrubbing liquid or exhaust gas would pull a certain amount of amperage on the fan motor to maintain a constant speed. When the exhaust gas and scrubbing liquid are added, the fan motor amperage will increase to maintain that speed. Based on this concept, the basis for the fan motor amperage operating limit in the 2017 NESHAP amendments was that a drop in fan motor amperage below a certain point showed that the motor would no longer turn the fan properly (because, for example, the belt that connects the motor to the fan was slipping or broken), which in turn would mean the scrubber was not operating as well as it was during the emissions performance test.

As facilities began to plan their repeat performance test required by the 2017 NESHAP amendments and determine the appropriate operating parameters, they discovered that the method dictated to set the fan motor amperage did not accurately represent proper scrubber performance and submitted alternative monitoring requests. The alternative monitoring requests that EPA received explained that setting the fan amperage operating limit as outlined in the 2017 NESHAP amendments at 40 CFR 63.864(j)(5)(i)(A) could result in a minimum limit that does not correlate with scrubber emissions-reduction performance and cannot be achieved at all times, leading to deviations of the amperage operating parameter even when the fan is turning as designed and the scrubber is operating properly to achieve the required HAP reduction. More details on these alternative monitoring requests were provided in the memorandum titled, *Smelt Dissolving Tank Scrubber Operating Parameter Review,* in the docket for the 2019 proposed amendments (EPA Docket Item No. EPA–HQ–OAR–2014–0741–0277).

As explained in the preamble to the 2019 proposed amendments, after reviewing how the SDT scrubbers in question operate, the EPA agrees that use of the average fan motor amperage measured during the performance test to establish the fan amperage limit as dictated in 40 CFR 63.864(j)(5)(i)(A) of the 2017 NESHAP amendments can be problematic because it does not necessarily correlate with proper operation of the scrubber. The EPA's intent with adding the fan motor amperage alternative as part of the 2017 NESHAP amendments was to add regulatory flexibility while ensuring proper scrubber operation, not to arbitrarily set an operating limit that may not be met, even while the SDT scrubber is operating properly. The requirement for determining the fan motor amperage during the performance test to set the minimum limit was included in the 2017 NESHAP amendments (40 CFR part 63, subpart MM) which apply to new and existing sources (see 82 FR 47328, October 11, 2017) and in the NSPS promulgated in 2014 (40 CFR part 60, subpart BBa) which applies to new sources only (*see* 79 FR 18952, April 4, 2014). The issue was not identified in public comments on either rule but was discovered as existing sources began to implement the 2017 NESHAP amendments.

Upon further review of the EPA's responses to historical alternative monitoring requests included in the ADI, recent requests for alternative monitoring, and other available information, we recognize that the requirement to monitor fan amperage directly and establish a minimum fan amperage limit based on the average amperage measured during the performance test may result in deviations even when the scrubber is properly operating. Some facilities were approved by the EPA to use indicators of fan operation closely related to fan amperage (*e.g.,* RPM) and engineering design considerations when setting the site-specific fan amperage limit indicative of proper scrubber operation. For more details, see the memorandum titled *Smelt Dissolving Tank Scrubber Operating Parameter Review,* in the docket for the 2019 proposed amendments (EPA Docket Item No. EPA–HQ–OAR–2014–0741–0277).

To continue with our original intent to measure scrubber performance with an alternative method in these rules, the EPA proposed this rule to modify the language at 40 CFR 63.864(e)(10)(iii) and (j)(5)(i) to clarify how wet scrubber parameter limits are to be established and that fan amperage or RPM can be used to demonstrate compliance for the

[1] Fan amperage refers to the amperage delivered to the fan motor.

SDT scrubbers in question. Specifically, the EPA proposed to replace 40 CFR 63.864(j)(5)(i)(A) with a requirement to set the minimum scrubbing liquid flow rate operating limit as the lowest of the 1-hour average scrubbing liquid flow rate values associated with each test run demonstrating compliance with the applicable emission limit. This requirement was inadvertently left out of the 2017 NESHAP amendments but was required by other sections of the rule. Additionally, we proposed to add a new subsection, 40 CFR 63.864(j)(5)(i)(B), to clarify how wet scrubber fan amperage operating limits should be established.

The proposed text in 40 CFR 63.864(j)(5)(i)(B) included the same requirement that was previously in the 40 CFR 63.864(j)(5)(i) introductory paragraph, which stated that the scrubber pressure drop operating limit must be set as the lowest of the 1-hour average pressure drop values associated with each test run demonstrating compliance with the applicable emission limit, but also added that for dynamic or low-energy entrainment scrubbers, operating limits could be set using one of three methods specified in paragraphs 40 CFR 63.864(j)(5)(i)(B)(*1*) through (*3*).

- In 40 CFR 63.864(j)(5)(i)(B)(*1*), the EPA proposed to clarify that, for SDT dynamic wet scrubbers operating at ambient pressure or for low-energy entrainment scrubbers where fan speed does not vary, the minimum fan amperage operating limit must be set as the midpoint between the lowest of the 1-hour average fan amperage values associated with each test run demonstrating compliance with the applicable emission limit and the no-load amperage value. Additionally, the proposed regulatory text specified that the no-load amperage value must be determined using manufacturers specifications or by performing a no-load test of the fan motor, and that it must be verified that the scrubber fan is operating within 5 percent of the design RPM during the emissions performance test. A definition of ''no-load fan amperage'' was proposed in 40 CFR 63.861.
- In 40 CFR 63.864(j)(5)(i)(B)(*2*), the EPA proposed to allow use of percent full load amperage (PFLA) to demonstrate compliance and require that the minimum PFLA to the fan motor be set as the percent of full load amperage under no-load, plus 10 percent. Because the no-load value represents the amperage pulled by the motor without a fan belt (*i.e.,* the fan is not engaged), the additional 10 percent was proposed to ensure that the belt has not broken, and the fan is engaged during operation. This new subsection also proposed requiring verification that the scrubber fan is operating within 5 percent of the design RPM during the emissions performance test.
- In 40 CFR 63.864(j)(5)(i)(B)(*3*), the EPA proposed to allow use of RPM to demonstrate compliance and a requirement that the minimum RPM be set at 95 percent of the design RPM. The EPA also proposed a conforming amendment in 40 CFR 63.867(c)(3)(iii)(C)(*1*) to incorporate this language.

Commenters on the 2019 proposed amendments supported the proposed methods for setting minimum operating limits in 40 CFR 63.864(j)(5)(i)(B)(*1*) and (*2*), except for the requirement to verify that the scrubber fan is operating within 5 percent of the design RPM during the emissions performance test. Commenters strongly opposed the requirement to verify the design RPM for reasons detailed in the response-to-comments memorandum, *Response to Comments to Proposed Rule Amending 40 CFR part 63 Subpart MM and 40 CFR part 60 Subpart BBa,* in the docket for this action. In brief, the commenters explained that facilities monitoring fan amperage may not have instrumentation in place to monitor fan RPM and may not have the design RPM value available; that there are safety issues associated with attempting to obtain a one-time measurement of RPM; and that operating within 5 percent of the design RPM during the emissions performance test is irrelevant if the performance test shows compliance with the PM emission limit and fan amperage (which is proportional to RPM) is monitored. In response to these comments, the requirement to verify that the scrubber fan is operating within 5 percent of the design RPM during the emissions performance test was removed from the final rule. All other requirements in 40 CFR 63.864(j)(5)(i)(B)(*1*) and (*2*) were finalized as proposed.

One commenter requested that the EPA modify the proposed definition of ''no load fan amperage'' by adding the following language to the end of the definition, ''or the coupling to a direct drive fan was disconnected.'' The phrase was added as requested for the final rule.

Regarding the proposed 40 CFR 63.864(j)(5)(i)(B)(*2*), a commenter requested clarification on how the minimum PFLA operating limit should be calculated for an SDT scrubber fan and suggested that the EPA present an example PLFA calculation in the preamble to the final rule. In response to this request, we clarified in the final rule that the PFLA is calculated by dividing the no-load amperage value by the highest of the 1-hour average fan amperage values associated with each test run demonstrating compliance with the applicable emission limit in 40 CFR 63.862 multiplied by 100 *and then adding 10 percent* (emphasis added). We are including the following example of how to calculate the minimum PFLA. However, we are not including this equation in the final rule to avoid the need to renumber several subsequent rule equations.

Minimum PFLA = (No-load fan amperage/highest 1-hour average of fan amperages) × 100% + 10%

Where:

- The no-load fan amperage represents the amperage pulled by the fan motor when the fan is operating under no-load determined using manufacturers specifications or by performing a no-load test of the fan motor.
- The highest 1-hour average of fan amperages is the highest of the 1-hour average fan amperage values associated with each test run demonstrating compliance with the applicable emission limit in 40 CFR 63.862.

For example, assume Facility ''A'' performs a no-load test of their SDT scrubber's fan motor by running the motor without the fan belt attached. The measured fan amperage during the no-load test is 70 amperage. During a performance test of the SDT scrubber, the highest 1-hour average of the fan amperage values associated with each of the three test runs demonstrating compliance with the applicable emission limit is 179 amperage. Using these two amperage values, Facility A would calculate the PFLA alternative operating parameter limit for their SDT scrubber fan as follows:

Minimum PFLA = (70/179) × 100% + 10% = 49%

One commenter addressed the proposed 40 CFR 63.864(j)(5)(i)(B)(*3*), which would require the minimum fan RPM limit to be set as 5 percent lower than the design RPM. The commenter stated that the EPA should revise this requirement to be 5 percent lower than the lowest 1-hour average RPM measured during each test run demonstrating compliance with the applicable emission limit. The commenter explained that a facility could have modified the fan motor such that it is no longer operating at the design RPM, or it could have no documentation of the design RPM, but it is the performance of the scrubber during the stack test that matters. In response to this comment, 40 CFR

63.864(j)(5)(i)(B)(*3*) was finalized by revising it to require that the minimum RPM be set as 5 percent lower than the lowest 1-hour average RPM associated with each test run demonstrating compliance with the applicable emission limit, as requested. The EPA agrees that an operating limit based on the lowest 1-hour average RPM measured during each test run (for facilities that measure RPM) is adequate to demonstrate ongoing operation of the SDT scrubber. The 5-percent margin suggested by the commenter will allow for variability. The conforming revisions to 40 CFR 63.867(c)(3)(iii)(C)(1) that acknowledge RPM as an operating parameter for SDT dynamic or low-energy scrubbers were also finalized as proposed.

2. Other NESHAP Amendments

In addition to clarifying how to set SDT fan amperage operating limits, the EPA also proposed to correct the following cross-reference errors in the promulgated 40 CFR part 63, subpart MM NESHAP:

- An incorrect paragraph reference in the definition of ''modification'' in 40 CFR 63.861;
- An incorrect paragraph reference in 40 CFR 63.864(e)(10)(iii), referring to 40 CFR 63.864(e)(3)(i) instead of 40 CFR 63.864(e)(10)(i) as intended;
- Omission of reference to wet scrubber liquid flow rate in 40 CFR 63.864(j)(5) which specifies how to establish operating limits; and
- Incorrect paragraph references in 40 CFR 63.864(j)(1), (3), and (5) which cross-referenced requirements that were proposed (81 FR 97046, December 30, 2016) but not finalized for establishing site-specific electrostatic precipitator (ESP) operating limits for secondary voltage and secondary current (or total secondary power) for each ESP collection field. Instead of finalizing site-specific ESP operating limits, the EPA finalized a requirement to maintain proper operation of the ESP's automatic voltage control (82 FR 47328, October 11, 2017), but inadvertently kept the cross-references to the proposed ESP operating limits in the final rule.

The EPA did not receive any comments on the first three corrections noted above and is finalizing these amendments as proposed.

A comment was received regarding the EPA's proposal to eliminate the reference to 40 CFR 63.864(e)(1) in 40 CFR 63.864(j)(1), (3), and (5) which pertain to determination of operating limits. The commenter stated that the EPA should also eliminate reference to 40 CFR 63.864(e)(2) in these sections because 40 CFR 63.864(e)(2) references 40 CFR 63.864(e)(1). The EPA agrees with the commenter's suggestion and eliminated the cross-reference to 40 CFR 63.864(e)(2) in 40 CFR 63.864(j)(1), (3), and (5) for the final amendments. 40 CFR 63.864(e)(2) specifies parameter monitoring requirements for kraft or soda recovery furnaces or lime kilns using an ESP followed by a wet scrubber. 40 CFR 63.864(e)(2) refers to 40 CFR 63.864(e)(1) to require facilities to maintain proper ESP automatic voltage control and refers to 40 CFR 63.864(e)(10) to require facilities to monitor wet scrubber parameters. While 40 CFR 63.864(j)(1), (3), and (5) no longer reference 40 CFR 63.864(e)(1) and (2), these sections retain the reference to 40 CFR 63.864(e)(10) with respect to wet scrubber operating limits.

B. What are the final amendments to the NSPS?

1. Alternative To Monitoring Pressure Drop for Certain SDT Scrubbers

The EPA proposed similar amendments to the fan amperage requirements in the NSPS as discussed in section II.A of this preamble for consistency between the NESHAP and NSPS that apply to the same scrubbers. Specifically, NSPS amendments were proposed for 40 CFR 60.284a(b)(2)(iii), (c)(3)(i), (c)(4), and (d)(4)(ii) and 40 CFR 60.287a(b)(4)(i) to add RPM language. As proposed, 40 CFR 60.284a(c)(4) referred to the procedures for establishing the SDT fan amperage operating limit in the NESHAP (40 CFR 63.864(j)(5)(i)(B)). A commenter requested that 40 CFR 60.284a(c)(4) specify how scrubber fan amperage operating limits should be set rather than referencing 40 CFR 63.864(j)(5)(i)(B) of the NESHAP (as proposed). The commenter noted that incorporation of the NESHAP reference is inappropriate because it requires the operating parameter limit to be set based on a performance test that demonstrates compliance with the applicable emission limit in 40 CFR 63.862, not 40 CFR 60.282a. In response to this comment, the EPA removed the reference to 40 CFR 63.864(j)(5)(i)(B) in 40 CFR 60.284a(c)(4) and replaced it with specific language describing how to set scrubber fan amperage operating parameter limits. The procedures added to the NSPS in 40 CFR 60.284a(c)(4) are consistent with the procedures specified in the NESHAP. The EPA also added the definition of ''no-load fan amperage'' to 40 CFR 60.281a because the definition is referenced in the language added in 40 CFR 63.864(j)(5)(i)(B).

2. Other NSPS Amendments

The EPA proposed to correct a cross-reference error in the promulgated Kraft Pulp Mills NSPS (40 CFR part 60, subpart BBa). Specifically, the EPA proposed to amend incorrect paragraph references in 40 CFR 60.285a(b)(1) and 60.285a(d)(1) intended to cross-reference the rule's oxygen correction equation. No comments were received on these changes so the EPA is finalizing these amendments as proposed.

III. Summary of Cost, Environmental, and Economic Impacts

A. What are the affected sources?

The sources affected by this action are chemical pulp mills that use SDTs equipped with low-energy entrainment scrubbers or dynamic scrubbers that operate near atmospheric pressure. We estimate that there are 54 facilities that utilize these types of scrubbers.

B. What are the air quality impacts?

There are no air quality impacts associated with the final amendments.

C. What are the cost impacts?

No cost impacts are estimated to be associated with this action because the action serves only to provide regulatory clarity. This action reduces the likelihood that facilities will choose to submit site-specific alternative monitoring requests but does not change the scope of any regulatory requirements.

D. What are the economic impacts?

There are no economic impacts associated with the final amendments.

E. What are the benefits?

Because these final amendments are not considered economically significant, as defined by Executive Order 12866, and because we did not estimate any emission reductions associated with the action, we did not estimate any benefits from reducing emissions.

IV. Statutory and Executive Order Reviews

Additional information about these statutes and Executive Orders can be found at *https://www.epa.gov/laws-regulations/laws-and-executive-orders.*

A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulations and Regulatory Review

This action is not a significant regulatory action and was, therefore, not submitted to the Office of Management and Budget (OMB) for review.

B. Executive Order 13771: Reducing Regulations and Controlling Regulatory Costs

This action is not an Executive Order 13771 regulatory action because this action is not significant under Executive Order 12866.

C. Paperwork Reduction Act (PRA)

This action does not impose any new information collection burden under the PRA. OMB has previously approved the information collection activities contained in the existing regulation (40 CFR part 63, subpart MM) and has assigned OMB control number 2060–0377. This action does not change the information collection requirements.

D. 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. This action does not create any new requirements or burdens, and no costs are associated with this final action.

E. Unfunded Mandates Reform Act (UMRA)

This action does not contain any unfunded mandate as described in UMRA, 2 U.S.C. 1531–1538, and does not significantly or uniquely affect small governments. The action imposes no enforceable duty on any state, local, or tribal governments or the private sector.

F. Executive Order 13132: Federalism

This action does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government.

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

This action does not have tribal implications, as specified in Executive Order 13175. The EPA does not know of any pulp mills owned or operated by Indian tribal governments or located within tribal lands. Thus, Executive Order 13175 does not apply to this action.

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

The EPA interprets Executive Order 13045 as applying to those regulatory actions that concern environmental health or safety risks that the EPA has reason to believe may disproportionately affect children, per the definition of ''covered regulatory action'' in section 2–202 of the Executive Order. This action is not subject to Executive Order 13045 because it does not concern an environmental health risk or safety risk.

I. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

This action is not subject to Executive Order 13211 because it is not a significant regulatory action under Executive Order 12866.

J. National Technology Transfer and Advancement Act (NTTAA)

This rulemaking does not involve technical standards.

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

The EPA believes that this action does not have disproportionately high and adverse human health or environmental effects on minority populations, low-income populations, and/or indigenous peoples, as specified in Executive Order 12898 (59 FR 7629, February 16, 1994). This action does not affect the level of protection provided to human health or the environment.

L. Congressional Review Act (CRA)

This action is subject to the CRA, and the EPA will submit a rule report to each House of the Congress and to the Comptroller General of the United States. This action is not a ''major rule'' as defined by U.S.C. 804(2).

List of Subjects

40 CFR Part 60

Environmental protection, Administrative practice and procedures, Air pollution control, Intergovernmental relations, Monitoring requirements.

40 CFR Part 63

Environmental protection, Administrative practice and procedures, Air pollution control, Hazardous substances, Intergovernmental relations, Reporting and recordkeeping requirements.

Andrew Wheeler,

Administrator.

For the reasons set forth in the preamble, the Environmental Protection Agency amends 40 CFR parts 60 and 63 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.*

Subpart BBa—Standards of Performance for Kraft Pulp Mill Affected Sources for Which Construction, Reconstruction, or Modification Commenced After May 23, 2013

■ 2. In § 60.281a, add in alphabetical order the definition for ''No-load fan amperage'' to read as follows:

§ 60.281a Definitions.

* * * * *

No-load fan amperage means, for the purposes of this subpart, the amperage pulled by the fan motor when the fan is operating under no-load, specifically the amperage value the motor would use if the fan belt was removed or the coupling to a direct drive fan was disconnected.

* * * * *

■ 3. In § 60.284a, revise paragraphs (b)(2)(iii), (c)(3)(i), (c)(4), and (d)(4)(ii) to read as follows:

§ 60.284a Monitoring of emissions and operations.

* * * * *

(b) * * *

(2) * * *

(iii) As an alternative to pressure drop measurement under paragraph (b)(2)(i) of this section, a monitoring device for measurement of fan amperage or revolutions per minute (RPM) may be used for smelt dissolving tank dynamic scrubbers that operate at ambient pressure or for low-energy entrainment scrubbers where the fan speed does not vary.

* * * * *

(c) * * *

(3) * * *

(i) Calculate 12-hour block averages from the recorded measurements of wet scrubber pressure drop (or smelt dissolving tank scrubber fan amperage or RPM) and liquid flow rate (or liquid supply pressure), as applicable.

* * * * *

(4) During the initial performance test required in § 60.285a, the owner or operator must establish site-specific operating limits for the monitoring parameters in paragraphs (b)(2) through (4) of this section by continuously monitoring the parameters and determining the arithmetic average value of each parameter during the performance test. The arithmetic

average of the measured values for the three test runs establishes your minimum site-specific operating limit for each wet scrubber or ESP parameter (except for smelt dissolving tank scrubber fan amperage or RPM). For smelt dissolving tank scrubber fan amperage, set the minimum operating limit using one of the methods in paragraphs (c)(4)(i) or (ii) of this section. For smelt dissolving tank scrubber RPM, the minimum RPM must be set as specified in paragraph (c)(4)(iii) of this section. Multiple performance tests may be conducted to establish a range of parameter values. The owner or operator may establish replacement operating limits for the monitoring parameters during subsequent performance tests using the test methods in § 60.285a.

(i) The minimum fan amperage operating limit must be set as the midpoint between the lowest of the 1-hour average fan amperage values associated with each test run demonstrating compliance with the applicable emission limit in § 60.282a and the no-load amperage value. The no-load amperage value must be determined using manufacturers specifications, or by performing a no-load test of the fan motor for each smelt dissolving tank scrubber; or

(ii) The minimum percent full load amperage (PFLA) to the fan motor must be set as the percent of full load amperage under no-load, plus 10 percent. The PFLA is calculated by dividing the no-load amperage value by the highest of the 1-hour average fan amperage values associated with each test run demonstrating compliance with the applicable emission limit in § 60.282a multiplied by 100 and then adding 10 percent. The no-load amperage value must be determined using manufacturers specifications, or by performing a no-load test of the fan motor for each smelt dissolving tank scrubber.

(iii) The minimum RPM must be set as 5 percent lower than the lowest 1-hour average RPM associated with each test run demonstrating compliance with the applicable emission limit.

* * * * *

(d) * * *

(4) * * *

(ii) All 12-hour block average scrubber pressure drop (or fan amperage or RPM, if used as an alternative under paragraph (b)(2)(iii) of this section) measurements below the minimum site-specific limit established during performance testing during times when BLS or lime mud is fired (as applicable), except during startup and shutdown.

* * * * *

■ 4. In § 60.285a, revise paragraphs (b)(1) and (d)(1) to read as follows:

§ 60.285a Test methods and procedures.

* * * * *

(b) * * *

(1) Method 5 of appendix A–3 of this part must be used to determine the filterable particulate matter concentration. The sampling time and sample volume for each run must be at least 60 minutes and 0.90 dscm (31.8 dscf). Water must be used as the cleanup solvent instead of acetone in the sample recovery procedure. The particulate concentration must be corrected to the appropriate oxygen concentration according to § 60.284a(c)(1)(iii).

* * * * *

(d) * * *

(1) Method 16 of appendix A–6 of this part must be used to determine the TRS concentration. The TRS concentration must be corrected to the appropriate oxygen concentration using the procedure in § 60.284a(c)(1)(iii). The sampling time must be at least 3 hours, but no longer than 6 hours.

* * * * *

■ 5. In § 60.287a, revise paragraph (b)(4)(i) to read as follows:

§ 60.287a Recordkeeping.

* * * * *

(b) * * *

(4) * * *

(i) Records of the pressure drop of the gas stream through the control equipment (or smelt dissolving tank scrubber fan amperage or RPM), and

* * * * *

PART 63—NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES

■ 6. The authority citation for part 63 continues to read as follows:

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

Subpart MM—National Emission Standards for Hazardous Air Pollutants for Chemical Recovery Combustion Sources at Kraft, Soda, Sulfite, and Stand-Alone Semichemical Pulp Mills

■ 7. In § 63.861, revise the definition for ''Modification'' and add in alphabetical order the definition for ''No-load fan amperage'' to read as follows:

§ 63.861 Definitions.

* * * * *

Modification means, for the purposes of § 63.862(a)(1)(ii)(D)(*1*), any physical change (excluding any routine part replacement or maintenance) or operational change that is made to the air pollution control device that could result in an increase in PM emissions.

* * * * *

No-load fan amperage means, for purposes of this subpart, the amperage pulled by the fan motor when the fan is operating under no-load, specifically the amperage value the motor would use if the fan belt was removed or the coupling to a direct drive fan was disconnected.

* * * * *

■ 8. In § 63.864, revise paragraphs (e)(10)(iii), (j)(1), (3), and (5) to read as follows:

§ 63.864 Monitoring requirements.

* * * * *

(e) * * *

(10) * * *

(iii) As an alternative to pressure drop measurement under paragraph (e)(10)(i) of this section, a monitoring device for measurement of fan amperage or fan revolutions per minute (RPM) may be used for smelt dissolving tank dynamic scrubbers that operate at ambient pressure or for low-energy entrainment scrubbers where the fan speed does not vary.

* * * * *

(j) * * *

(1) During the initial or periodic performance test required in § 63.865, the owner or operator of any affected source or process unit must establish operating limits for the monitoring parameters in paragraphs (e)(10) through (14) of this section, as appropriate; or

* * * * *

(3) The owner or operator of an affected source or process unit may establish expanded or replacement operating limits for the monitoring parameters listed in paragraphs (e)(10) through (14) of this section and established in paragraph (j)(1) or (2) of this section during subsequent performance tests using the test methods in § 63.865.

* * * * *

(5) New, expanded, or replacement operating limits for the monitoring parameter values listed in paragraphs (e)(10) through (14) of this section should be determined as described in paragraphs (j)(5)(i) and (ii) of this section.

(i) The owner or operator of an affected source or process unit that uses a wet scrubber must set minimum operating limits as described in paragraph (j)(5)(i)(A) and (B) of this section.

(A) Set the minimum scrubbing liquid flow rate operating limit as the lowest of the 1-hour average scrubbing liquid flow rate values associated with each test run demonstrating compliance with the applicable emission limit in § 63.862.

(B) Set the minimum scrubber pressure drop operating limit as the lowest of the 1-hour average pressure drop values associated with each test run demonstrating compliance with the applicable emission limit in § 63.862; or for a smelt dissolving tank dynamic wet scrubber operating at ambient pressure or for low-energy entrainment scrubbers where fan speed does not vary, set the minimum operating limit using one of the methods in paragraph (j)(5)(i)(B)(*1*) through (*3*) of this section.

(*1*) The minimum fan amperage operating limit must be set as the midpoint between the lowest of the 1-hour average fan amperage values associated with each test run demonstrating compliance with the applicable emission limit in § 63.862 and the no-load amperage value. The no-load amperage value must be determined using manufacturers specifications, or by performing a no-load test of the fan motor for each smelt dissolving tank scrubber; or

(*2*) The minimum percent full load amperage (PFLA) to the fan motor must be set as the percent of full load amperage under no-load, plus 10 percent. The PFLA is calculated by dividing the no-load amperage value by the highest of the 1-hour average fan amperage values associated with each test run demonstrating compliance with the applicable emission limit in § 63.862 multiplied by 100 and then adding 10 percent. The no-load amperage value must be determined using manufacturers specifications, or by performing a no-load test of the fan motor for each smelt dissolving tank scrubber; or

(*3*) The minimum RPM must be set as 5 percent lower than the lowest 1-hour average RPM associated with each test run demonstrating compliance with the applicable emission limit.

(ii) [Reserved]

* * * * *

■ 9. In § 63.867, revise paragraph (c)(3)(iii)(C)(*1*) to read as follows:

§ 63.867 Reporting requirements.

* * * * *

(c) * * *

(3) * * *

(iii) * * *

(C) * * *

(1) The operating limits established during the performance test for scrubbing liquid flow rate and pressure drop across the scrubber (or alternatively, fan amperage or RPM if used for smelt dissolving tank scrubbers).

* * * * *

[FR Doc. 2020–22938 Filed 11–4–20; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 180

[EPA–HQ–OPP–2020–0112; FRL–10015–69]

Thiamine Mononitrate; Exemption From the Requirement of a Tolerance

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This regulation establishes an exemption from the requirement of a tolerance for residues of thiamine mononitrate (CAS Reg. No. 532–43–4) when used as an inert ingredient (enzyme cofactor) in pesticide products applied to/on all growing crops pre-harvest, limited to 0.1% (by weight) in pesticide formulations. SciReg, Inc on behalf of Valagro, S.p.A submitted a petition to EPA under the Federal Food, Drug, and Cosmetic Act (FFDCA), requesting an establishment of an exemption from the requirement of a tolerance. This regulation eliminates the need to establish a maximum permissible level for residues of thiamine mononitrate when used in accordance with this exemption. Vitamin B1 is also known as thiamine mononitrate. Throughout this document and for purposes of issuing the tolerance, EPA is using the name ''thiamine mononitrate'' to be consistent with standard agency nomenclature for the identification of this substance.

DATES: This regulation is effective November 5, 2020. Objections and requests for hearings must be received on or before January 4, 2021 and must be filed in accordance with the instructions provided in 40 CFR part 178 (see also Unit I.C. of the **SUPPLEMENTARY INFORMATION**).

ADDRESSES: The docket for this action, identified by docket identification (ID) number EPA–HQ–OPP–2020–0112, 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.

Due to the public health concerns related to COVID–19, the EPA Docket Center (EPA/DC) and Reading Room is closed to visitors with limited exceptions. The staff continues to provide remote customer service via email, phone, and webform. For the latest status information on EPA/DC services and docket access, visit *https://www.epa.gov/dockets.*

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

SUPPLEMENTARY INFORMATION:

I. General Information

A. Does this action apply to me?

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

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

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

You may access a frequently updated electronic version of 40 CFR part 180 through the Government Printing Office's e-CFR site at *http://www.ecfr50/cgi-bin/text-idx?&c=ecfr&tpl=/ecfrbrowse/Title40/40tab_02.tpl.*

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

Under FFDCA section 408(g), 21 U.S.C. 346a, any person may file an objection to any aspect of this regulation and may also request a hearing on those objections. You must file your objection or request a hearing on this regulation in accordance with the instructions provided in 40 CFR part 178. To ensure proper receipt by EPA, you must identify docket ID number EPA–HQ–OPP–2020–0112 in the subject line on the first page of your submission. All objections and requests for a hearing

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[EPA–HQ–OAR–2017–0757; FRL–10013–44–OAR]

RIN 2060–AT90

Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Review

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This action finalizes amendments to the oil and natural gas new source performance standards (NSPS) promulgated in 2012 and 2016. These amendments remove sources in the transmission and storage segment from the source category, rescind the NSPS (including both the volatile organic compounds (VOC) and methane requirements) applicable to those sources, and separately rescinds the methane-specific requirements of the NSPS applicable to sources in the production and processing segments. Furthermore, the U.S. Environmental Protection Agency (EPA) adopts an interpretation of Clean Air Act (CAA) section 111 under which the EPA, as a predicate to promulgating NSPS for certain air pollutants, must determine that the pertinent pollutant causes or contributes significantly to dangerous air pollution.

DATES: This final rule is effective on September 14, 2020.

ADDRESSES: The EPA established a docket for this action under Docket ID No. EPA–HQ–OAR–2017–0757. All documents in the docket are listed on the *https://www.regulations.gov/* website. Although listed, some information is not publicly available, *e.g.,* Confidential Business Information or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the internet and will be publicly available only in hard copy form. Publicly available docket materials are available electronically through *https://www.regulations.gov/.* Out of an abundance of caution for members of the public and our staff, the EPA Docket Center and Reading Room are closed to the public, with limited exceptions, to reduce the risk of transmitting COVID–19. Our Docket Center staff will continue to provide remote customer service via email, phone, and webform. For further information and updates on EPA Docket Center services, please visit us online at *https://www.epa.gov/dockets.* The EPA continues to carefully and continuously monitor information from the Center for Disease Control, local area health departments, and our Federal partners so that we can respond rapidly as conditions change regarding COVID–19.

FOR FURTHER INFORMATION CONTACT: For questions about this final action, contact Ms. Amy Hambrick, Sector Policies and Programs Division (E143–05), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711; telephone number: (919) 541–0964; fax number: (919) 541–0516; and email address: *hambrick.amy@epa.gov.*

SUPPLEMENTARY INFORMATION: *Preamble acronyms and abbreviations.* We use multiple acronyms and terms in this preamble. While this list may not be exhaustive, to ease the reading of this preamble and for reference purposes, the EPA defines the following terms and acronyms here:

AEO Annual Energy Outlook
APA Administrative Procedure Act
BSER best system of emission reduction
CAA Clean Air Act
CFR Code of Federal Regulations
CH_4 methane
CO carbon monoxide
CO_2 carbon dioxide
CO_2 Eq. carbon dioxide equivalent
EAV equivalent annualized value
EG Emission Guidelines
EGU Electricity Generating Units
EIA U.S. Energy Information Administration
EPA Environmental Protection Agency
GHG greenhouse gases
GHGI greenhouse gas inventory
GHGRP Greenhouse Gas Reporting Program
HAP hazardous air pollutant(s)
H_2S hydrogen sulfide
ICR Information Collection Request
IR infrared
kt kilotons
MMT million metric tons
NAAQS National Ambient Air Quality Standards
NAICS North American Industry Classification System
NEI National Emissions Inventory
NEMS National Energy Modeling System
NO_X nitrogen oxides
NSPS new source performance standards
NTTAA National Technology Transfer and Advancement Act
OGI optical gas imaging
OMB Office of Management and Budget
PM particulate matter
$PM_{2.5}$ PM with a diameter of 2.5 micrometers or less
PM_{10} PM with a diameter of 10 micrometers or less
PRA Paperwork Reduction Act
PV present value
RFA Regulatory Flexibility Act
RIA Regulatory Impact Analysis
SC-CH_4 social cost of methane
SCF significant contribution finding
scfh standard cubic feet per hour
SIP state implementation plan
SO_2 sulfur dioxide
tpy tons per year
the Court United States Court of Appeals for the District of Columbia Circuit
TSD technical support document
UMRA Unfunded Mandates Reform Act
U.S. United States
VOC volatile organic compounds

Organization of this document. The information presented in this preamble is organized as follows:

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J. National Technology Transfer and Advancement Act (NTTAA)
K. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations
L. Congressional Review Act (CRA)

I. Executive Summary

A. Purpose and Summary of the Regulatory Action

The EPA is finalizing amendments to its 2012 and 2016 Rules affecting the oil and natural gas industry, titled, respectively, ''Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews; Final Rule'' (''2012 Rule'') [1] and ''Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources; Final Rule'' (''2016 Rule'').[2] Those rules established NSPS for VOC emissions from the oil and natural gas industry, and the 2016 Rule also established NSPS for greenhouse gases (GHG), in the form of limitations on methane, for that industry.[3] The amendments that the EPA is finalizing are intended to continue existing protections from emission sources within the source category that the EPA originally listed for regulation under CAA section 111—termed the Oil and Natural Gas Production Source Category—while removing regulatory duplication.

In response to President Donald J. Trump's March 2017 Executive Order on Promoting Energy Independence and Economic Growth, the EPA has reviewed the 2012 and 2016 Rules with attention to whether they ''unduly burden the development of domestic energy resources beyond the degree necessary to protect the public interest or otherwise comply with the law'' and, thus, should be ''suspend[ed], revise[d], or rescind[ed]''.[4 5] From this review, the EPA has determined that some of the requirements under those rules are inappropriate. For example, some of these requirements affect sources that are not appropriately identified as part of the regulated source category. In addition, some of the requirements under the 2016 Rule are unnecessary insofar as they impose redundant requirements. Accordingly, the EPA is acting to rescind those requirements while maintaining health and environmental protections from appropriately identified emission sources within the regulated source category.[6]

Specifically, the EPA is finalizing what it referred to as the primary proposal in the September 24, 2019, proposed action (''2019 Proposal''). Thus, this final rule contains two main actions. First, the EPA is finalizing a determination that the source category includes only the production and processing segments of the industry and is rescinding the standards applicable to the transmission and storage segment of the industry. This determination is based on the EPA's review of the original source category listing and its 2012 and 2016 Rules' interpretations of, and its 2016 Rule's revision to, the scope of the source category, which, as revised, covered sources in the transmission and storage segment. Having reexamined its prior rulemakings regarding the scope of this source category and the transmission and storage segment, the EPA has determined that the revision in the 2016 Rule of the original source category was not appropriate. Because the EPA is determining that the original source category did not cover the transmission and storage segment, and that this segment constitutes a separate source category from the production and processing segments, the EPA was authorized to list it for regulation under CAA section 111(b) only by making a cause-or-contribute-significantly and endangerment finding as required by the statute, which the EPA never did. Accordingly, in this first action, the EPA is rescinding the standards applicable to sources in the transmission and storage segment of the oil and natural gas industry.

Second, the EPA is separately rescinding the methane requirements of the NSPS applicable to sources in the production and processing segments. The EPA is concluding that those methane requirements are redundant with the existing NSPS for VOC and, thus, establish no additional health protections. The emission source control technologies that apply to the sources achieve reductions in both methane and VOC emissions, and the recordkeeping and other requirements overlap as well. Rescinding the applicability of the 2016 Rule requirements to methane emissions, while leaving the applicability to VOC emissions in place, will not affect the amount of methane emission reductions that those requirements will achieve.

This final rule also concludes that, as a prerequisite for newly regulating any air pollutant that the EPA did not consider when listing or initially regulating the source category, CAA section 111 requires the EPA to make a finding that emissions of that air pollutant from the source category cause or contribute significantly (which we term the significant contribution finding, or SCF) to air pollution which may reasonably be anticipated to endanger public health or welfare (which we sometimes refer to as dangerous air pollution). Further, the final rule determines that the SCF for methane that the EPA made in the alternative in the 2016 Rule was invalid and did not meet this statutory standard, for two reasons: (i) The EPA made that finding on the basis of methane emissions from the production, processing, and transmission and storage segments, instead of just the production and processing segments; and (ii) the EPA failed to support that finding with either established criteria or some type of reasonably explained and intelligible standard or threshold for determining when an air pollutant contributes significantly to dangerous air pollution. The fact that the 2016 Rule's SCF for methane was invalid provides another basis for rescinding the methane requirements for the

[1] 77 FR 49490 (August 16, 2012).

[2] 81 FR 35824 (June 3, 2016).

[3] Docket ID No. EPA–HQ–OAR–2010–0505.

[4] Executive Order 13783, ''Promoting Energy Independence and Economic Growth,'' section 1(c) (March 28, 2017); *see also* section 7(a) (specifically directing the EPA to review the 2016 Rule, ''and any rules and guidance issued pursuant to it, for consistency with the policy set forth in section 1 of this order and, if appropriate, [to], as soon as practicable, suspend, revise, or rescind the guidance, or publish for notice and comment proposed rules suspending, revising, or rescinding those rules'').

[5] 82 FR 16331 (April 4, 2017) (review of 2016 Rule pursuant to Executive Order 13783, signed by the EPA Administrator).

[6] We note that the EPA is addressing certain specific reconsideration issues—fugitive emissions requirements at well sites and compressor stations, well site pneumatic pump standards, and the requirements for certification of closed vent systems by a professional engineer (PE)—in a separate final rule. *See* Docket ID Item No. EPA–HQ–OAR–2010–0505–7730 and 82 FR 25730.

production and processing segments. While the EPA took comment in the 2019 Proposal on what criteria should inform its judgment as to whether a pollutant causes or contributes significantly to dangerous air pollution, the EPA is not taking further action on such criteria in this rulemaking.

B. Costs and Benefits

The EPA has projected the compliance cost reductions, emissions changes, and forgone benefits that may result from the final rule for the years of analysis, 2021 to 2030. The projected cost reductions and forgone benefits are presented in detail in the Regulatory Impact Analysis (RIA) accompanying this final rule. The EPA notes that the projected cost reductions and forgone benefits are directly associated with the rescission of the NSPS applicable to sources in the transmission and storage segment of the source category and not the rescission of methane from the production and processing segments.

A summary of the key results of this final rule is presented in Table 1.[7] Table 1 presents the present value (PV) and equivalent annualized value (EAV), estimated using discount rates of 7 and 3 percent, of the changes in benefits, costs, and net benefits, as well as the change in emissions under the final rule. Here, the EPA refers to the cost reductions as the ''benefits'' of this rule and the forgone benefits as the ''costs'' of this rule in Table 1. The net benefits are the benefits (cost reductions) minus the costs (forgone benefits).

TABLE 1—COST REDUCTIONS, FORGONE BENEFITS, AND FORGONE EMISSIONS REDUCTIONS OF THE FINAL RULE, 2021 THROUGH 2030

[Millions 2016$]

	7-Percent discount rate		3-Percent discount rate	
	PV	EAV	PV	EAV
Benefits (Total Cost Reductions)	$31	$4.1	$38	$4.3
Costs (Forgone Benefits)	17	2.2	63	7.2
Net Benefits [1]	14	1.9	−25	−2.9
Emissions	Forgone Reductions			
Methane (short tons)	400,000			
VOC (short tons)	11,000			
Hazardous Air Pollutant(s) (HAP) (short tons)	330			
Methane (million metric tons carbon dioxide equivalent (CO_2 Eq.))	9			

[1] **Note:** Estimates may not sum due to independent rounding.

This final rule is expected to result in benefits (compliance cost reductions) for affected owners and operators. The PV of these benefits (cost reductions), discounted at a 7-percent rate, is estimated to be about $31 million, with an EAV of about $4.1 million (Table 1). Under a 3-percent discount rate, the PV of cost reductions is $38 million, with an EAV of $4.3 million (Table 1).

The estimated costs (forgone benefits) include the monetized climate effects of the projected increase in methane emissions under the final rule. The PV of these climate-related costs (forgone benefits), discounted at a 7-percent rate, is estimated to be about $17 million, with an EAV of about $2.2 million (Table 1). Under a 3-percent discount rate, the PV of the climate-related costs (forgone benefits) is about $63 million, with an EAV of about $7.2 million (Table 1). The EPA also expects that there will be increases in VOC and HAP emissions as a result of this final rule. While the EPA expects that the forgone VOC emission reductions may also degrade air quality and adversely affect health and welfare effects associated with exposure to ozone, particulate matter with a diameter of 2.5 micrometers or less ($PM_{2.5}$), and HAP, we are unable to quantify these effects at this time. This omission should not imply that these forgone benefits do not exist. To the extent that the EPA were to quantify these ozone and particulate matter (PM) impacts, the Agency would estimate the number and value of avoided premature deaths and illnesses using an approach detailed in the Particulate Matter National Ambient Air Quality Standards (NAAQS) and Ozone NAAQS RIA (U.S. EPA, 2012; U.S. EPA, 2015).

The PV of the net benefits of this rule, discounted at a 7-percent rate, is estimated to be about $14 million, with an EAV of about $1.9 million (Table 1). Under a 3-percent discount rate, the PV of net benefits is about $−25 million, with an EAV of about $−2.9 million (Table 1).

II. General Information

A. Does this action apply to me?

Categories and entities potentially affected by this action include:

TABLE 2—INDUSTRIAL SOURCE CATEGORIES AFFECTED BY THIS ACTION

Category	NAICS code [1]	Examples of regulated entities
Industry	211120	Crude Petroleum Extraction.
	211130	Natural Gas Extraction.
	221210	Natural Gas Distribution.
	486110	Pipeline Distribution of Crude Oil.
	486210	Pipeline Transportation of Natural Gas.
Federal Government		Not affected.

[7] In a separate action, the EPA is finalizing technical reconsideration amendments to 40 CFR part 60, subpart OOOOa (EPA–HQ–OAR–2017–0483; FRL–10013–60–OAR; FR Doc. 2020–18115). These technical amendments where proposed in October 2018. 83 FR 52056. Please reference that final rule for the summary and rationale of those technical changes. Please refer to the RIA for both rules to see the combined impacts.

TABLE 2—INDUSTRIAL SOURCE CATEGORIES AFFECTED BY THIS ACTION—Continued

Category	NAICS code [1]	Examples of regulated entities
State/local/tribal government		Not affected.

[1] North American Industry Classification System (NAICS).

This table is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be affected by this action. Other types of entities not listed in the table could also be affected by this action. To determine whether your entity is affected by this action, you should carefully examine the applicability criteria found in the final rule. If you have questions regarding the applicability of this action to a particular entity, consult the person listed in the **FOR FURTHER INFORMATION CONTACT** section, your air permitting authority, or your EPA Regional representative listed in 40 CFR 60.4 (General Provisions).

B. How do I obtain a copy of this document, background information, and other related information?

In addition to being available in the docket, an electronic copy of the final action is available on the internet. Following signature by the Administrator, the EPA will post a copy of this final action at *https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry.* Following publication in the **Federal Register**, the EPA will post the **Federal Register** version of the final rule and key technical documents at this same website. A redline version of the regulatory language that incorporates the final changes in this action is available in the docket for this action (Docket ID No. EPA–HQ–OAR–2017–0757). Additional background information about this final rule, including industry and emissions information, regulatory history, litigation background, other notable events, related Federal actions, and a comprehensive summary and rationale of the proposed options can be found at 84 FR 50244 (September 24, 2019).

C. 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 United States Court of Appeals for the District of Columbia Circuit (''the Court'') by November 13, 2020. 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 for the EPA to convene a proceeding for reconsideration, ''[i]f the person raising an objection can demonstrate to the EPA that it was impracticable to raise such objection within [the period for public comment] or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule.'' Any person seeking to make such a demonstration to us should submit a Petition for Reconsideration to the Office of the Administrator, U.S. Environmental Protection Agency, Room 3000, WJC South 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. Environmental Protection Agency, 1200 Pennsylvania Ave. NW, Washington, DC 20460.

III. Background

The EPA reviewed the relevant background in the 2019 Proposal, including discussing the oil and natural gas industry and its emissions, 84 FR 50247 through 50; the statutory background, *Id.* at 50251; the regulatory history and litigation background regarding performance standards for the oil and natural gas industry, *Id.* at 50251 and 52; other notable events, including the March 28, 2017, Executive Order that led the EPA to initiate this rulemaking, *Id.* at 50252 and 53; and related state and Federal regulatory actions, *Id.* at 50253 and 54. The EPA incorporates that information by reference and will not repeat it here.

Since the 2019 Proposal, the EPA has updated information on the oil and natural gas industry emissions inventories based on the recently released Inventory of United States Greenhouse Gas Emissions and Sinks: 1990–2018 (published April 13, 2020) and the 2017 National Emissions Inventory (NEI) (released February 2020). In Tables 3 to 7 below, the EPA provides the updated estimate of emissions of methane, VOC, and sulfur dioxide (SO_2) from oil and natural gas industry sources.

Methane emissions in the U.S. and from the oil and natural gas industry. Official U.S. estimates of national level GHG emissions and sinks are developed by the EPA for the U.S. GHG Inventory (GHGI) to comply with commitments under the United Nations Framework Convention on Climate Change. The U.S. GHGI, which includes recent trends, is organized by industrial sectors. The oil and natural gas production, natural gas processing, and natural gas transmission and storage sectors emit 25 percent of U.S. anthropogenic methane. Table 3 below presents total U.S. anthropogenic methane emissions for the years 1990, 2008, and 2018.

TABLE 3—U.S. METHANE EMISSIONS BY SECTOR

[Million metric ton carbon dioxide equivalent (MMT CO_2 eq.)]

Sector	1990	2008	2018
Oil and Natural Gas Production, and Natural Gas Processing and Transmission and Storage	185	185	163
Oil and Natural Gas Production, and Natural Gas Processing	128	153	129
Oil and Natural Gas Transmission and Storage	57	32	34
Landfills	180	125	111

TABLE 3—U.S. METHANE EMISSIONS BY SECTOR—Continued

[Million metric ton carbon dioxide equivalent (MMT CO_2 eq.)]

Sector	1990	2008	2018
Enteric Fermentation	164	174	178
Coal Mining	97	76	53
Manure Management	37	54	62
Other Oil and Gas Sources	44	18	13
Wastewater Treatment	15	15	14
Other Methane Sources [8]	57	51	57
Total Methane Emissions	779	698	650

Emissions from the Inventory of United States Greenhouse Gas Emissions and Sinks: 1990–2018 (published April 13, 2020), calculated using global warming potential (GWP) of 25. *Note:* Totals may not sum due to rounding.

Table 4 below presents total methane emissions from natural gas production through transmission and storage and petroleum production, for years 1990, 2008, and 2018, in MMT CO_2 Eq. (or million metric tonnes CO_2 Eq.) of methane.

TABLE 4—U.S. METHANE EMISSIONS FROM NATURAL GAS AND PETROLEUM SYSTEMS

[MMT CO_2 eq.]

Sector	1990	2008	2018
Oil and Natural Gas Production and Natural Gas Processing and Transmission (Total)	185	185	163
Natural Gas Production	61	100	82
Natural Gas Processing	21	11	12
Natural Gas Transmission and Storage	57	32	34
Petroleum Production	45	42	35

Emissions from the Inventory of United States Greenhouse Gas Emissions and Sinks: 1990–2018 (published April 13, 2020), calculated using GWP of 25. *Note:* Totals may not sum due to rounding.

VOC and SO_2 emissions in the U.S. and from the oil and natural gas industry. Official U.S. estimates of national level VOC and SO_2 emissions are developed by the EPA for the NEI, for which states are required to submit information under 40 CFR part 51, subpart A. Data in the NEI may be organized by various data points, including sector, NAICS code, and Source Classification Code. The oil and natural gas sources emit 5.8 and 2.4 percent of U.S. VOC and SO_2, respectively. Tables 5 and 6 below present total U.S. VOC and SO_2 emissions by sector, respectively, for the year 2017, in kilotons (kt) (or thousand metric tons).

TABLE 5—U.S. VOC EMISSIONS BY SECTOR

[kt]

Sector	2017
Biogenics—Vegetation and Soil	25,823
Fires—Wildfires	4,578
Oil and Natural Gas Production, and Natural Gas Processing and Transmission	2,504
Fires—Prescribed Fires	2,042
Solvent—Consumer and Commercial Solvent Use	1,610
Mobile—On-Road non-Diesel Light Duty Vehicles	1,507
Mobile—Non-Road Equipment—Gasoline	1,009
Other VOC Sources [9]	4,045
Total VOC Emissions	43,118

Emissions from the 2017 NEI (released April 2020). *Note:* Totals may not sum due to rounding.

TABLE 6—U.S. SO_2 EMISSIONS BY SECTOR

[kt]

Sector	2017
Fuel Combustion—Electric Generation—Coal	1,319
Fuel Combustion—Industrial Boilers, Internal Combustion Engines—Coal	212
Mobile—Commercial Marine Vessels	183

[8] Other sources include rice cultivation, forest land, stationary combustion, abandoned oil and natural gas wells, abandoned coal mines, mobile combustion, composting, and several sources emitting less than 1 MMT CO_2 Eq. in 2018.

TABLE 6—U.S. SO_2 EMISSIONS BY SECTOR—Continued

[kt]

Sector	2017
Industrial Processes—Not Elsewhere Classified	138
Fires—Wildfires	135
Industrial Processes—Chemical Manufacturing	123
Oil and Natural Gas Production and Natural Gas Processing and Transmission	65
Other SO_2 Sources [10]	551
Total SO_2 Emissions	2,726

Emissions from the 2017 NEI (released April 2020). *Note:* Totals may not sum due to rounding.

Table 7 below presents total VOC and SO_2 emissions from oil and natural gas production through transmission and storage, for the year 2017, in kt (or thousand metric tons).

TABLE 7—U.S. VOC AND SO_2 EMISSIONS FROM NATURAL GAS AND PETROLEUM SYSTEMS

[kt]

Sector	VOC	SO_2
Oil and Natural Gas Production and Natural Gas Processing and Transmission (Total)	2,504	65
Oil and Natural Gas Production	2,478	41
Natural Gas Processing	12	23
Natural Gas Transmission and Storage	14	1

Emissions from the 2017 NEI, (published April 2020), in kt (or thousand metric tons). *Note:* Totals may not sum due to rounding.

IV. 2019 Proposal

On September 24, 2019, the EPA issued a proposed rulemaking (2019 Proposal) to amend the 2012 Rule and 2016 Rule for the oil and natural gas industry that would remove regulatory duplication and save the industry millions of dollars in compliance costs each year, while maintaining health and environmental protections from oil and natural gas sources that the Agency considers appropriate to regulate in this rule.[11] The EPA issued the proposal in response to President Trump's Executive Order on Promoting Energy Independence and Economic Growth. Generally speaking, that order directs agencies to review existing regulations that potentially ''burden the development or use of domestically produced energy resources,'' including oil and natural gas, and to suspend, revise, or rescind such regulatory requirements if appropriate. The proposal included a primary regulatory option and an alternative regulatory option. The primary option proposed to remove all sources in the transmission and storage segment of the oil and natural gas industry from regulation under the NSPS, both for VOC and for GHG. The primary option separately proposed to rescind the methane requirements in the 2016 Rule that apply to sources in the production and processing segments of the industry. The alternative option proposed to rescind the methane requirements that apply to all sources in the oil and natural gas industry, without removing any sources from the source category as defined in the 2016 Rule. The EPA additionally solicited comment on alternative interpretations of the EPA's legal authority to regulate pollutants under CAA section 111.

CAA section 111 requires the EPA to set NSPS for categories of stationary sources that the EPA has listed (''source categories'') because they cause, or significantly contribute to, air pollution that may reasonably be anticipated to endanger public health or welfare. The Agency's original source category listing for the oil and natural gas industry, issued in 1979, included only the crude oil and natural gas production and natural gas processing segments of the industry. However, in the 2012 Rule and 2016 Rule, the EPA interpreted the 1979 listing to have established the scope of the source category as including the industry's transmission and storage segment. In the 2016 Rule, the EPA also, as an alternative, expanded the source category to include the transmission and storage segment. In the 2019 Proposal, the EPA proposed to remove sources in the transmission and storage segment from the Oil and Natural Gas Production source category on the grounds that the Agency had erred in the 2012 and 2016 Rules when it had interpreted or expanded the source category, because the transmission and storage segment of the industry is functionally separate from the production and processing segment. The EPA further stated that a separate SCF would be necessary for that segment to be listed as a source category for regulation. The proposal further stated that the emissions limits that apply to sources in the transmission and storage segment in the 2012 Rule and 2016 Rule would be rescinded because that segment would be removed from the source category. Finally, the EPA proposed to rescind emissions requirements for methane for sources located in the production and processing segments on grounds that those requirements are redundant to the requirements for VOC. The proposal made clear that the emissions limits for VOC would remain for the production and processing segments.

In the alternative proposal, the EPA proposed to rescind the methane requirements in the 2016 Rule for all oil and natural gas sources, without removing the transmission and storage sources from the source category. Under this alternative, the rule would retain VOC standards for the production, processing, and transmission and storage segments of the industry. As with the primary proposal, the alternative proposal is based on the view that because the controls to reduce VOC emissions also reduce methane, separate methane requirements for the industry are redundant.

The EPA further stated that the proposed amendments would remove the Agency's obligation to develop emission guidelines (EG) to address methane emissions from existing sources under section 111(d) of the CAA. The EPA stated its belief that not

[9] Other sources include remaining sources emitting less than 1,000 kt VOC in 2017.

[10] Other sources include remaining sources emitting less than 100 kt SO_2 in 2017.

[11] 84 FR 50244.

regulating existing sources would have limited environmental impact, because some existing sources will ''modify'' such that they will become subject to requirements for new sources, and because the number of remaining sources may decline over time as they are shut down or become obsolete.

The EPA also took comment on an alternative interpretation of its legal authority to regulate pollutants under CAA section 111. In the 2016 Rule, the EPA took the position that the law did not require the Agency, as a prerequisite to regulating methane as part of the NSPS, to first make a separate determination that GHG emissions from the oil and natural gas industry cause, or significantly contribute to, dangerous air pollution (a pollutant-specific SCF). However, the Agency also made a finding in the alternative that if the CAA were interpreted to require a pollutant-specific SCF, then GHG emissions from the Oil and Natural Gas source category do cause or contribute significantly to dangerous air pollution. The 2019 Proposal solicited comment on three issues: (1) Whether the Agency should revise the interpretation it took in the 2016 Rule, so that CAA section 111 requires the EPA to make a pollutant-specific SCF for GHG emissions from the oil and natural gas industry as a predicate to regulation; (2) whether, if CAA section 111 does require a pollutant-specific SCF, whether the finding in the alternative in the 2016 Rule satisfied that requirement; and (3) what, if any, specific criteria the EPA should use to make a pollutant-specific SCF.

The EPA solicited comments on all aspects of the proposal during a 60-day public comment period. The EPA held a public hearing in Dallas, Texas, in October 2019; 105 speakers provided oral testimony and 32 observers attended. The EPA received almost 300,000 public comments on the proposed rule. The EPA is not responding to any late comment received.

V. Final Action and Rationale

A. Summary of Final Action

The EPA is finalizing what was referred to as the primary proposal in the 2019 Proposal. First, the final rule removes all sources in the transmission and storage segment of the oil and natural gas industry from regulation under the NSPS and removes all emissions limitations for both VOC and GHG for sources in the transmission and storage segment. Second, the final rule separately rescinds the standards for methane emissions in the 2016 Rule that apply to sources in the production and processing segments of the industry. Third, the final rule articulates the EPA's interpretation that under CAA section 111(b)(1)(A), as a prerequisite for newly regulating any air pollutant, the Agency is required to make a finding that emissions of the air pollutant, from the source category, cause or contribute significantly to air pollution which may reasonably be anticipated to endanger public health or welfare. Further, the final rule concludes that the alternative SCF made by the EPA in the 2016 Rule was invalid and did not meet this statutory standard.

B. Rationale

1. Revision of the Source Category To Remove Transmission and Storage Segment

As noted above, the EPA is finalizing its proposal to remove the transmission and storage segment entirely from the source category and rescind the NSPS requirements applicable to sources within that segment. This final action is based on the EPA's determination that its 2012 and 2016 rulemakings that interpreted or expanded the source category to include sources in that segment were improper. The following discussion provides background on CAA section 111, the history of the Oil and Natural Gas Production source category, and the rationale for this final decision.

Under CAA section 111(b)(1)(A), the EPA must ''publish . . . a list of categories of stationary sources, emissions from which, in the judgment of the Administrator, cause[ ], or contribute[ ] significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare.'' Further, CAA section 111(b)(1)(A) directs that ''from time to time thereafter'' the EPA ''shall revise'' this ''list'' of categories of stationary sources. Following the ''inclusion of a category of stationary sources in a list,'' the EPA then proposes and promulgates ''standards of performance for new sources within such category.'' CAA Section 111(b)(1)(B). Thereafter, the EPA ''shall . . . review and, if appropriate, revise such standards.'' *Id.*

CAA section 111(b)(1)(A) does not include any specific criteria for determining the reasonable scope of a given ''category'' of ''stationary sources'' beyond the requirement that the Administrator make a finding that, in his or her ''judgment,'' emissions from the ''category of sources . . . cause[ ], or contribute[ ]significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare.'' Accordingly, the EPA is afforded some measure of discretion in determining at the outset the scope of a source category.

In 1978, the EPA published ''Priorities for New Source Performance Standards Under the Clean Air Act Amendments of 1977.''[12] The purpose of this document was to implement the requirements of CAA section 111(f) to develop and apply a methodology for identifying, establishing, and prioritizing the source categories that should be considered first for in-depth analysis prior to NSPS promulgation under CAA section 111. For purposes of the 1978 analysis, the EPA aggregated emissions from ''oil and gas production fields'' and ''natural gas processing'' as part of the ''Crude Oil and Natural Gas Production Plant'' source category. The EPA identified this aggregated source category as a major source of hydrocarbon (HC) and SO_2 emissions. When the EPA finalized the priority list in 1979, it revised the name of the source category as ''Crude Oil and Natural Gas Production.'' 49 FR 49222 (August 21, 1979).

In 1985, the EPA promulgated two rulemakings establishing NSPS for the Crude Oil and Natural Gas Production source category. These were 40 CFR part 60, subpart KKK—Standards of Performance for Equipment Leaks of VOC from Onshore Natural Gas Processing Plants (50 FR 26124, June 23, 1985); and subpart LLL—Standards of Performance for SO_2 Emissions from Onshore Natural Gas Processing (50 FR 40160, October 1, 1985). When it first proposed 40 CFR part 60, subpart KKK, the EPA noted that the ''crude oil and natural gas production industry encompasses the operations of exploring for crude oil and natural gas products, removing them from beneath the earth's surface, and processing these products for distribution to petroleum refineries and gas pipelines.''[13] The EPA repeated that description of the identified source category when it proposed 40 CFR part 60, subpart LLL, explaining that the ''crude oil and natural gas production industry encompasses not only processing of the natural gas (associated or not associated with crude oil) but operations of exploration, drilling, and subsequent removal of the gas from porous geologic formations beneath the earth's surface.''[14]

In 2012, the EPA reviewed the VOC and SO_2 standards and at the same time

[12] Priorities for New Source Performance Standards Under the Clean Air Act Amendments of 1977. April 1978. EPA–450/3–78–019.

[13] 49 FR 2637 (January 20, 1984).

[14] 49 FR 2658 (January 20, 1984).

established new requirements for additional stationary sources of VOC emissions that had not been regulated in the 1985 rulemaking (*e.g.,* well completions, pneumatic controllers, storage vessels, and compressors)—''Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews—Final Rule'' (77 FR 49490, August 16, 2012). In the preamble of the 2011 proposal for the 2012 Rule, the EPA interpreted the 1979 listing as indicating that ''the currently listed Oil and Natural Gas source category covers all operations in this industry (*i.e.,* production, processing, transmission, storage and distribution).'' ''Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews—Proposed Rule,'' 76 FR 52738, 52745 (August 23, 2011). Further, the EPA stated that ''[t]o the extent there are oil and gas operations not covered by the currently listed Oil and Natural Gas source category. . . ., we hereby modify the category list to include all operations in the oil and natural gas sector.'' *Id.* The stated basis for that proposed decision was that ''[s]ection 111(b) of the CAA gives the EPA the broad authority and discretion to list and establish NSPS for a category that, in the Administrator's judgment, causes or contributes significantly to air pollution which may reasonably be anticipated to endanger public health or welfare.'' *Id.* No additional discussion of this listing position was provided in the 2011 proposal.

In the 2012 final rulemaking, the EPA promulgated NSPS for emission sources in the production, processing, and transmission and storage segments, 77 FR 49492, and stated that ''[t]he listed Crude Oil and Natural Gas Production source category covers, at a minimum, those operations for which we are establishing standards in this final rule.'' *Id.* at 49496. In responding to comments, the EPA took the position that it was not actually revising the source category to include emission sources in the transmission and storage segment, but rather, was interpreting the 1979 listing to be ''broad,'' and interpreting the 1985 rulemaking as ''view[ing] this source category listing very broadly,'' *Id.* at 49514, so that, in the EPA's view, the source category was already sufficiently broad to include that segment.[15]

In 2016, the EPA promulgated additional NSPS (40 CFR part 60, subpart OOOOa) for the Crude Oil and Natural Gas Production source category (81 FR 35824, June 3, 2016). As the EPA did in the 2012 Rule, the EPA took the position that the 1979 listing was broad enough to encompass the transmission and storage segment and that the 1985 rulemakings confirmed that broad listing. 81 FR 35832 (''The scope of the 1978 Priority List is further demonstrated by the Agency's pronouncements during the NSPS rulemaking that followed the listing.''). The EPA stated that the inclusion of the transmission and storage segment into the original 1979 source category was warranted because equipment and operations at production, processing, transmission and storage facilities are a sequence of functions that are interrelated and necessary for getting the recovered gas ready for distribution. Nevertheless, the EPA recognized that the scope of the prior listing may have had some ambiguity. Accordingly, ''as an alternative,'' the EPA finalized a revision of the category to broaden it, so that ''[a]s revised, the listed oil and natural gas source category includes oil and natural gas production, processing, transmission, and storage'' and the EPA changed the source category name to be ''Crude Oil and Natural Gas source category.'' (81 FR 35840).

a. Scope of 1979 Listing Action

For this final rule, the EPA has reviewed the original 1979 listing of the Crude Oil and Natural Gas Production source category and the associated background materials and now finds that its 2012 and 2016 interpretation of the 1979 listing (*i.e.,* that the 1979 listing included natural gas transmission and storage) was erroneous. *See F.C.C.* v. *Fox Television Stations, Inc.,* 556 U.S. 502 (2009) (an agency may revise its policy, but must demonstrate that the new policy is permissible under the statute and is supported by good reasons, taking into account the record of the previous rule). The EPA received comments on the 2019 Proposal concerning this issue and the associated rationale. These comments are provided, along with the EPA's responses, in section VIII.A of this preamble and in Chapter 5 of the Response to Comments Document for this action. None of the comments received resulted in a change in the EPA's rationale and conclusions from proposal. The following explains our decision.[16]

While the EPA has listed source categories that are broad,[17] the silence of the 1979 listing as to the transmission and storage segment suggests that the segment was *not* considered for inclusion at the time of the listing. Principles of administrative law require that in order for something (in this case, the transmission and storage segment) to be subject to regulation, the EPA should provide for and explain such regulation clearly. Moreover, where the EPA has remained silent on any explanation for its choice of regulation, the Court has held, ''a rule without a stated reason is necessarily arbitrary and capricious.'' *Small Refiner Lead Phase-Down Task Force* v. *U.S. EPA,* 705 F.2d 506, 551 (1983). Accordingly, if the EPA had intended for the 1979 listing to include the transmission and storage segment, the Agency's failure to explain that decision would have rendered it arbitrary and capricious. It is reasonable to presume that the Agency did not act arbitrarily and capriciously, and, therefore, that its silence regarding the transmission and storage segment indicated that it did not intend to cover that segment in the 1979 listing.

Additionally, to the extent there was ambiguity in the original 1979 listing, the EPA made clear its interpretation in 1984, when the EPA proposed to set the first standards of performance for sources within the Crude Oil and Natural Gas Production source category (*i.e.,* 40 CFR part 60, subpart KKK). The views the Agency expressed concerning the scope of the source category are particularly relevant because this rulemaking was conducted shortly after the listing and because it established the initial NSPS. In this proposal, the EPA described the category as ''encompass[ing] the operations of exploring for crude oil and natural gas products, removing them from beneath the earth's surface and processing these products for distribution to petroleum refineries and gas pipelines,'' but this description made no reference to the subsequent activities of transmission

[15] In the 2012 Rule rulemaking, the EPA referred to the distribution segment of the oil and natural gas industry, which entails transporting natural gas to the end user. 76 FR 52738, 52745 (August 23, 2011) (proposed rule); 77 FR 49514, 77 FR 49493 (Table 2) (August 16, 2012) (final rule). However, in the 2016 Rule, the EPA clarified that the scope of the Oil and Natural Gas Production and Processing source category includes the transmission and storage segment, but not the distribution segment. In addition, the EPA has never treated any sources in the distribution segment as subject to the requirements of NSPS subpart OOOO or OOOOa.

[16] In 1979, the EPA named the source category ''Crude Oil and Natural Gas Production source category.'' In 2016, the EPA changed the source category name to be ''Crude Oil and Natural Gas source category.'' Because this final rule rescinds the 2016 expansion, the EPA is finalizing the source category's name back to how it read in 1979.

[17] The EPA also has listed narrow source categories, as noted in section VIII.A of this preamble.

and storage of crude oil and natural gas products.[18] This description is reasonably read to establish that sources in the transmission and storage segment were not included in the Crude Oil and Natural Gas Production source category as listed in 1979.

Similarly, in the same sentence, the EPA defined the scope of the source category as encompassing oil operations up to the point of distribution to petroleum refineries, which are a separate source category. In this manner, the EPA indicated that the Crude Oil and Natural Gas Production source category includes operations from well sites (exploration, drilling, and removal) and natural gas processing plants (processing). While gathering and boosting compressor stations were not specified, it is reasonable to conclude that they are also included because they are located between two covered sites, the well site and the processing plant. However, to reiterate, subsequent operations, such as transmission and storage, and distribution were not included.

In the 1984 proposal, the EPA added that ''there are several VOC emission points within this industry,'' which the Agency categorized as process, storage, and equipment leaks. 49 FR 2637. In the 2016 NSPS, the EPA used this description of the three sets of emission points as support for the proposition that the Agency previously intended the source category to include transmission and storage. Specifically, the EPA stated that ''these emissions can be found throughout the various segments of the natural gas industry.'' 81 FR 35832. The EPA has closely reexamined the language of the 1984 proposal and found that, importantly, in the descriptions of these three categories of emission points, it is clear that the EPA considered these emission sources only in the production and processing segments. Therefore, while it is true that there are process, storage, and equipment leak emissions throughout the oil and natural gas sector, the discussion in the 1984 proposal entirely focused on these sources in the production and processing segments, and made no reference to the transmission and storage segment. The following discusses each of those three sets of sources in more detail.

With respect to process sources, the 1984 proposal states that they include well systems, field oil and natural gas separators, wash tanks, settling tanks, and other sources. The proposal further states that process sources remove the crude oil and natural gas from beneath the earth and separate gas and water from the crude oil. 49 FR 2637. This description of the process emission point clearly refers to the production and processing segments and is silent concerning the transmission and storage segment.

For the second set of emission points, storage sources, the 1984 proposal states that they include field storage tanks, condensate tanks, and cleaned oil tanks. These tanks emit VOC, the pollutant addressed in the 1984 proposal. These three types of tanks are common in the production segment and/or at natural gas processing plants; as gas is separated from oil, condensate and impurities, these tanks are used to store oil and condensate, which contain VOC. As such, these tanks are storage sources of VOC emissions. In contrast, storage at natural gas transmission and storage facilities refers to storage of gas, mostly in the underground storage reservoirs. Because the gas stored in underground reservoirs is pipeline quality natural gas (95–98 percent methane), these storage facilities in the transmission and storage segment are not emission points of concern for VOC, or any of the other pollutants identified in the 1984 proposal as being emitted from the oil and gas industry. Additionally, the cited discussion in the proposal made no explicit mention of transmission and storage facilities. Furthermore, there are no oil tanks or field tanks in the transmission and storage segment. As for condensate tanks, these tanks are rarely used at the transmission and storage segment because, as mentioned above, the gas that enters this segment is pipeline quality gas and, therefore, contains little to no condensate. Given the reference in the 1984 proposal to two other types of tanks that are also commonly found in the production and processing segments but absent in the transmission and storage segment, it is reasonable to conclude that the proposal's reference to condensate tanks was also intended to be limited to the production and processing segments. For all of these reasons, the better reading of the 1984 proposal discussion on storage tanks is that it was limited only to such tanks located in the production and processing segments, and was not intended to encompass tanks located in the transmission and storage segment.

Similarly, the 1984 proposal describes the equipment leak emission points as referring to the production and processing segments of the Oil and Natural Gas source category and is silent concerning the transmission and storage segment. The proposal explains that equipment leaks of VOC can occur from ''pumps, valves, compressors, open ended lines or valves, and pressure relief devices used in onshore crude oil and natural gas *production* (emphasis added).'' *Id.* Additionally, the preamble acknowledges that there is equipment used in crude oil and natural gas production and distinguishes this from equipment used in natural gas processing. The EPA examined the use of leak detection and repair work practices for equipment leaks of VOC at natural gas processing plants and explained in the preamble that the costs and emission reduction numbers for the application of these techniques at the ''widely dispersed'' crude oil and natural gas production sites were not known at that time. In this manner, the EPA clearly acknowledged the existence of equipment leaks at both the production and processing segments. In contrast, although equipment leaks do occur in the transmission and storage segment, the proposal makes no mention of leaks in that segment. Thus, each of the three sets of emission sources under consideration in the 1984 proposal clearly is in the production and processing segments, and the proposal is silent about the transmission and storage segment.

Another indicator that the 1984 proposal did not consider transmission and storage lies in the fact that this proposal addressed VOC emissions. As discussed below, the composition of the natural gas in the transmission and storage segment is significantly different than in the production and processing segments, as the transmission and storage segment contains considerably less VOC, and as a result, sources in that segment emit low amounts of VOC. In many areas of the country, particularly those that produce liquids and associated gas, the production and processing segments have high VOC-content gases, but the transmission and storage operations have substantially lower VOC-content gases. In light of the fact that the 1979 listing concerned VOC content (termed, at that time, HC), this difference between the segments further supports the view that the EPA would not have included transmission and storage in the 1979 listing. This corroborates that the proposal did not consider emission sources related to the transmission and storage of natural gas. Thus, although process, storage, and equipment leaks are emission sources that are present across the industry, including in natural gas transmission and storage, additional examination of the 1984 proposal makes it clear that it considered process, storage, and equipment leaks in only the production

[18] 49 FR 2637; *see* also 49 FR 2658.

and processing segments of the oil and natural gas industry.

For the reasons noted above, the EPA concludes that its statements in the 2012 and 2016 Rules that the 1979 listing of the Crude Oil and Natural Gas Production source category included the transmission and storage segment, and that the 1984 proposal confirmed that action, were in error. Rather, the record of the 1979 action indicates that the source category did not include that segment, and the Agency confirmed that narrower scope of the source category in its 1984 proposal to promulgate the initial set of NSPS.

b. Operations in the Transmission and Storage Segment Are Distinctly Different

As noted above, the 2016 Rule stated that the ''1979 listing of [the Crude Oil and Natural Gas Production] source category provides sufficient authority for this action'' to promulgate NSPS for sources in the transmission and storage segment, but then added that, ''to the extent that there is ambiguity in the prior listing, the EPA hereby . . ., as an alternative, . . . revis[es] . . . the category listing to broadly include the oil and natural gas industry.'' [19] ''As revised,'' the 2016 Rule continued, ''the listed oil and natural gas category includes oil and natural gas production, processing, transmission, and storage.'' [20] As discussed in the following paragraphs, the EPA is concluding, in line with the 2019 Proposal, that this alternative approach of revising the scope of the source category to include sources within the transmission and storage segment was also in error and should be rejected.

The EPA received comments on this issue, including the associated rationale. These comments are provided, along with the EPA's responses, in section VIII.A of this preamble and in Chapter 5 of the Response to Comments Document for this action. None of the comments received resulted in a change in the EPA's rationale and conclusions from proposal.

While CAA section 111(b)(1)(A) and (B) respectively authorize the EPA to ''revise,'' where warranted, both the ''list of source categories'' and ''standards of performance'' that the EPA has promulgated, nothing in CAA section 111 expressly authorizes or directs the EPA to ''revise'' a particular ''source category'' by altering its scope once the EPA has listed that source category. However, the EPA has inherent authority to reconsider, repeal, or revise past decisions, to the extent permitted by law, so long as the Agency provides a reasoned explanation. *See Sang Seup Shin* v. *INS,* 750 F.2d 122, 130 (D.C. Cir. 1984) (in absence of specific statutory prohibition, an agency has inherent authority to reconsider its decisions). The CAA complements the EPA's inherent authority to reconsider prior rulemakings by providing the Agency with broad authority to prescribe regulations as necessary, under CAA section 301(a). Even so, the authority to revise the scope of a source category must be exercised within reasonable boundaries and cannot be employed in a way that results in an unreasonable expansion of an existing source category. For the reasons discussed below, the EPA is not authorized to expand the scope of a listed source category to cover a new set of sources that are not sufficiently related to the sources in the pre-existing category, so that they constitute a separate source category for which the EPA would be required to make a new SCF and endangerment finding under CAA section 111(b)(1)(A) as a prerequisite to regulating them. Otherwise, expanding the source category by including new sources could be used to circumvent that requirement.

The EPA proposed to determine that the operations in the transmission and storage segment are not sufficiently related to the production and processing segments that were included in the original source category listing. In the 2016 Rule, the EPA held that the source category should be expanded because equipment and operations at production, processing, and transmission and storage facilities are a sequence of functions that are interrelated and necessary for getting the gas ready for distribution. In the 2019 Proposal, the EPA proposed to determine that this 2016 finding was unreasonable and proposed that transmission and storage operations are distinct from production and processing operations because (among other things) the natural gas that enters the transmission and storage segment has different composition and characteristics than the natural gas that enters the production and processing segments. 84 FR 50257.

While CAA section 111 does not define the term ''source category'' or use the phrase ''sufficiently related,'' this concept is inherent in the everyday definition of ''category.'' Merriam-Webster defines ''category'' as ''any of several fundamental and distinct classes to which entities or concepts belong,'' [21] and it defines a ''class[ ]'' as ''a group, set, or kind sharing *common* attributes'' (emphasis added).[22] Commenters point out what they view as commonalities among both the production and processing and transmission and storage segments. These comments implicitly acknowledge that, to be a ''category,'' the associated sources must have something in common, that is, they must be sufficiently related to merit being associated as part of the same category. The EPA may not have articulated the ''sufficiently related'' test in those terms in prior actions, but, again, that test is implicit in the everyday meaning of ''category.'' That is, for items to be part of a ''category'' they must have key things in common, and if they have substantial differences, they should not be included in the same category. Without this test, it would be difficult to develop a basis for ascertaining the scope of a category. For this reason, the EPA has in effect regularly applied this test. For example, fugitive VOC emissions from leaking equipment occurs across several industries, including the synthetic organic chemical manufacturing industry and the petroleum refinery industry, but there are substantial enough differences between those industries to warrant putting them in separate source categories, notwithstanding the fact that some of their equipment is similar. For another example, when proposing to expand the original Asphalt Roofing Plants source category listing to include other locations where the preparation of asphalt for roofing may take place, such as oil refineries, the EPA stated that, ''the emissions, processes, and applicable controls for blowing stills and asphalt storage tanks at oil refineries and asphalt processing plants are the same as those at asphalt roofing plants. It is therefore reasonable to treat the asphalt processing and roofing manufacture industry as a single category of sources for the purposes of establishing standards of performance.'' 45 FR 76428. By finding commonality in emissions, processes, and applicable controls for these otherwise different sources, the EPA determined that they should be part of the same source category.

[19] 81 FR 35833.

[20] *Id.* (footnote omitted).

[21] ''Category.'' *Merriam-Webster.com Dictionary,* Merriam-Webster, *https://www.merriam-webster.com/dictionary/category.* Accessed 21 May, 2020.

[22] ''Class.'' *Merriam-Webster.com Dictionary,* Merriam-Webster, *https://www.merriam-webster.com/dictionary/class.* Accessed 19 May, 2020.

In contrast, based on a reexamination of the processes and operations found in the transmission and storage segment, the EPA is finalizing its determination that transmission and storage sources are, in fact, sufficiently distinct from production and processing sources so that the Agency erred when, in the 2016 Rule, it revised the source category to include sources in the transmission and storage segment. Specifically, the EPA now concludes that the processes and operations found in the transmission and storage segment are distinct from those found in the production and processing segments because the purposes of the operations are different and because the natural gas that enters the transmission and storage segment has different composition and characteristics than the natural gas that enters the production and processing segments.

The primary operations of the production and processing segments are exploring crude oil and natural gas products beneath the earth's surface, drilling wells to extract these products, and processing the crude oil and field gas for distribution to petroleum refineries and natural gas pipelines. As stated previously in this section, the EPA described this source category's operations similarly when proposing 40 CFR part 60, subpart KKK, in 1984. 49 FR 2637. The primary purpose of these segments is to obtain the product and then, in the case of natural gas, to remove impurities from the extracted product. At a well site (production segment), crude oil and natural gas are extracted from the ground. Some processing can take place at the well site, such as the physical separation of gas, production fluids, and condensate. Of these products, crude oil and natural gas undergo successive, separate processing. Crude oil is separated from water and other impurities and transported to a refinery via truck, railcar, or pipeline. The EPA treats oil refineries as a separate source category, accordingly, for present purposes, the oil component of the production segment ends at the point of custody transfer at the refinery.[23] The separated gas (''field gas'') is then sent through gathering pipelines to the natural gas processing plant (processing segment).[24] At the processing plant, the field gas is converted to sales gas or pipeline quality gas. This involves several steps, including the extraction of natural gas liquids (*e.g.,* a mixture of propane, butane, pentane) from the field gas, the fractionation of these natural gas liquids into individual products (*e.g.,* liquid propane), or both extraction and fractionation. The final natural gas that exits in the processing plant is sales gas, which is predominantly methane. In these segments, the field gas has physically changed such that it is a usable product.

The operations of the production and processing segments differ from the transmission and storage segment operations because in the latter, the natural gas does not undergo changes in composition, except for some limited removal of liquids that condensed during the temperature and pressure changes as the natural gas moves through the pipeline. Therefore, the natural gas that enters the transmission and storage segment has approximately the same composition and characteristics as the natural gas that leaves the segment for distribution. The segment includes natural gas transmission compressor stations, whose primary operation is to move the natural gas through transmission pipelines by increasing the pressure. Dehydration, which can also occur at compressor stations, is a secondary operation used when the natural gas has collected water during transmission. As discussed in the 2019 Proposal, this differs from the significant natural gas processing in the production and processing segments, which involves a series of processing steps dependent on factors such as the type of natural gas (*e.g.,* wet or dry gas), market conditions, and company contract specifications. 84 FR 50258. At storage facilities, natural gas is injected into underground storage for use during peak seasons.[25] When demand increases, the natural gas is extracted from the underground storage, dehydrated to remove water that has entered during storage, compressed, and moved through distribution pipelines.

Analysis of the composition of natural gas on a nationwide basis in the various industry segments confirms the different character of the segments. In 2011 and subsequently in 2018, the EPA conducted an analysis of the composition, expressed in percent volume, of natural gas based on the methane, VOC, and HAP content across the various industry segments.[26] [27] For example, in 2011, the nationwide composition for the production segment, which included wells and unprocessed natural gas, consisted of approximately 83-percent methane, 4-percent VOC, and less than 1-percent HAP. In contrast, the transmission segment, which included pipeline and sales gas (*i.e.,* post processing), consisted of approximately 93-percent methane, 1-percent VOC, and less than 0.01-percent HAP. In 2018, the EPA reviewed new studies available and found similar results for the production segment. The nationwide composition for the production segment consisted of approximately 88-percent methane and 4-percent VOC. At proposal in 2019, we concluded that these differences in the gas composition demonstrated that the emissions profile is different following gas processing. After proposal in 2019, the EPA conducted a comprehensive analysis of data reported directly to the Greenhouse Gas Reporting Program (GHGRP) for reporting years 2015 through 2018 to determine whether the composition of natural gas, in terms of methane content, is statistically different between industry segments.[28] In order to determine whether the methane content is statistically different between industry segments, the analysis evaluated the average methane concentration for each segment based on the 2015–2018 GHGRP reporting data.[29]

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[23] *See* 40 CFR part 60, subparts J and Ja, and 40 CFR part 63, subparts CC and UUU.

[24] Natural gas with high methane content is referred to as ''dry gas,'' while natural gas with significant amounts of ethane, propane, or butane is referred to as ''wet gas.'' The degree and location of processing is dependent on various factors, one being the type of natural gas (*e.g.,* wet or dry gas). In some ''dry gas'' areas, the field gas, with naturally higher methane content, may go from the well site directly into the transmission and storage segment without processing in a gas processing plant. The fact that some produced natural gas does not require processing and can be transported directly into the transmission and storage segment does not diminish the differences between the production and processing segments, on the one hand, and the transmission and storage segment, on the other. Rather, it just means that some gas does not need to go through the processing segment.

[25] Storage can also take place in above ground storage vessels; however, it is the EPA's understanding that these are more commonly used after the local distribution company custody transfer (LDC) or commonly ''city gate,'' which has not been included in the source category at any point. The term ''local distribution company custody transfer,'' defined in 40 CFR part 60, subpart OOOOa, means a metering station where the LDC receives a natural gas supply from an upstream supplier, which may be an interstate transmission pipeline or a local natural gas producer, for delivery to customers through the LDC's intrastate transmission or distribution lines. This final rule adds the definition of LDC to 40 CFR part 60, subpart OOOO.

[26] Memorandum to Bruce Moore, U.S. EPA from Heather Brown, EC/R. ''Composition of Natural Gas for use in the Oil and Natural Gas Sector Rulemaking.'' July 2011. Docket ID Item No. EPA–HQ–OAR–2010–0505–0084.

[27] Memorandum to U.S. EPA from Eastern Research Group. ''Natural Gas Composition.'' November 13, 2018. Docket ID No. EPA–HQ–OAR–2017–0757.

[28] Memorandum. Analysis of Average Methane Concentrations in the Oil and Gas Industry Using Data Reported Under 40 CFR part 98 Subpart W. April 9, 2020. Included in Docket ID No. EPA–HQ–OAR–2017–0757.

[29] See Table 17 of Memorandum. Analysis of Average Methane Concentrations in the Oil and Gas

For oil and natural gas production, the analysis estimated an average methane content of 69 and 83 percent, respectively. For gathering and boosting,[30] the analysis estimated an average methane content of 81 percent, and for gas processing, an average methane content of 78 percent. The analysis estimated an average methane content of 94 percent for transmission and 95 percent for storage. The analysis performed additional calculations and statistical assessments to generate the final statistical analysis and subsequent conclusions.

This analysis found that there is a substantial difference in methane concentrations between (1) gas production, gathering and boosting, and gas processing and (2) transmission and storage. This agrees with earlier data and analyses and the conclusion that there is a difference in the emissions profile between the production and processing segments and the transmission and storage segment.

It should be noted that in regulating HAP from the oil and natural gas industry, the EPA created separate source categories for the production and processing segments, regulated under subpart HH of 40 CFR part 63; and the transmission and storage segment, regulated under subpart HHH of 40 CFR part 63. *See* 64 FR 32610, June 17, 1999. In addition, the EPA has made a similar distinction between other source categories with segments that handle the production and processing of a material and subsequent transport of the product. As the EPA noted in the 2019 Proposal, 84 FR 50258, one example is the petroleum industry, in which production facilities,[31] refineries,[32] and bulk gasoline terminals [33] all have operational differences, and the EPA placed them in three different source categories. Those operational differences are similar to the operational differences between the production and processing segments and the transmission and storage segment at issue in this final rule.

It should be noted that in the 2016 Rule, the EPA justified including the transmission and storage segment in the Crude Oil and Natural Gas source category partly because some similar equipment (*e.g.,* storage vessels, pneumatic pumps, compressors) is used across the industry. While that is true, the differences in the operations of, and the differences in emission profiles of, the different segments support excluding the transmission and storage segment from the source category. A review of 2016 Rule compliance reports from sources in the EPA Regions (3, 6, 8, 9, and 10) with the greatest oil and natural gas activity indicates that there were no storage vessels emitting more than 6 tons per year (tpy) VOC reported in the transmission and storage segment.[34] Therefore, even though there are storage vessels in the transmission and storage segment, the liquids (condensate) stored and the throughputs are such that the VOC emissions are significantly different. This supports our understanding that VOC emissions are lower in the transmission and storage segment and that any gas processing that occurs in the transmission and storage segment generally is limited to removing liquids that condensed during the temperature and pressure changes as the gas moves through the pipeline. In addition, there are types of equipment present in the production segment (*e.g.,* oil tanks, three-phase separators) and processes at natural gas processing plants (*e.g.,* natural gas liquid extraction, natural gas liquids fractionation, sulfur and CO_2 removal) that are either not present or uncommon at natural gas transmission and storage facilities.

In summary, there are distinct differences in the operations between oil and natural gas production and natural gas processing, on the one hand, and natural gas transmission and storage, on the other. The primary operations of the production and processing segments are exploring crude oil and natural gas products beneath the earth's surface, drilling wells that are used to extract these products, and processing the crude oil and field gas for distribution to petroleum refineries and natural gas pipelines. The operations of the production and processing segments differ from the transmission and storage segment operations because in the latter, the natural gas does not undergo changes in composition, except for some limited removal of liquids that condensed during the temperature and pressure changes as the natural gas moves through the pipeline. Second, there are statistically significant differences in the emissions profiles between the production and processing segments and the transmission and storage segment. Third, there are equipment types and processes present in the oil and natural gas production and processing segments that are not present, or not common, at natural gas transmission and storage facilities. The EPA is, therefore, finalizing a revised source category which excludes transmission and storage sources from the Crude Oil and Natural Gas Production source category.

As the EPA stated in the 2019 Proposal, the 2016 Rule's expansion of the source category to include sources in the transmission and storage segment did, in fact, exceed the reasonable boundaries of the EPA's authority to revise source categories. 81 FR 35833. The 2016 Rule also erred in purporting to list, under CAA section 111(b)(1)(A), the source category, as expanded to include transmission and storage sources, for regulation on grounds that it causes or contributes significantly to air pollution which may reasonably be anticipated to endanger public health or welfare. *Id.* Rather, in order to include the transmission and storage segment on the CAA section 111(b)(1)(A) list for regulation, the EPA is required to treat it as a separate source category and determine that in and of itself it causes or contributes significantly to air pollution which may reasonably be anticipated to endanger public health or welfare. The EPA did not make that determination in the course of promulgating the 2016 Rule. 81 FR 35833.

2. Rescission of the NSPS for Sources in Transmission and Storage Segment

A prerequisite for the EPA to promulgate an NSPS applicable to new sources is that the new sources must be in a source category that the EPA has listed under CAA section 111(b)(1). As stated in section V.B.1 of this preamble, the EPA is removing the transmission and storage segment from the source category. Accordingly, the promulgation of NSPS for transmission and storage sources was contrary to law, and as a result, the EPA is also rescinding the standards for both VOC and GHG emissions in the 2012 Rule and the 2016 Rule for emission sources located in the transmission and storage segment. Specifically, we are rescinding the requirements for compressor affected facilities, pneumatic controller affected facilities, storage vessel affected facilities, and the affected facility that is the collection of fugitive emissions components located at a compressor

Industry Using Data Reported Under 40 CFR part 98 Subpart W. April 9, 2020. Included in Docket ID No. EPA–HQ–OAR–2017–0757.

[30] Gathering and boosting is located between well sites and natural gas processing plants in the Oil and Natural Gas Production source category.

[31] U.S. EPA. ''Revised Prioritized List of Source Categories for NSPS Promulgation.'' March 1979. EPA–450/3–79–023.

[32] 38 FR 15406 (May 4, 1973); 39 FR 9315 (March 8, 1974).

[33] 45 FR 83126 (December 12, 1980); 48 FR 37578 (August 18, 1983).

[34] These reports have since been made available for public viewing at *https://www.foiaonline.gov/foiaonline/action/public/submissionDetails?trackingNumber=EPA-HQ-2018-001886&type=request.*

station, where these affected facilities are located downstream of the natural gas processing plant or, if no gas processing plant is present, after the point of custody transfer. To further clarify that the requirements do not apply to these units, we are adding a definition of ''natural gas transmission and storage segment'' which describes the boundaries of the segment. The definitions of ''natural gas processing plant'' and ''custody transfer'' are unchanged.

3. Status of Sources in Transmission and Storage Segment

The result of this final rule, as it relates to the transmission and storage segment, is that these sources are not part of a listed source category under CAA section 111(b)(1)(A) and, thus, are not subject to regulation under CAA section 111(b) (for new sources) or CAA section 111(d) (for existing sources that emit certain air pollutants). This is consistent with the treatment of emissions sources in other industries that the EPA has not listed as a source category under CAA section 111(b)(1)(A). In the future, the EPA may evaluate these emissions more closely and determine whether the transmission and storage segment should be listed as a source category under CAA section 111(b)(1)(A).[35]

4. Rescission of the Limitations on Methane for Sources in the Production and Processing Segments

As the second of the two main actions of this final rule, the EPA is also rescinding the limits on methane emissions for the NSPS applicable to sources in the production and processing segments. The EPA finds that, in the specific circumstances presented here, the EPA erred in establishing the methane NSPS because those requirements are redundant with the NSPS for VOC, establish no additional health protections, and are, thus, unnecessary. Even if the 2016 Rule's establishment of limits on methane emissions is not considered to be, the EPA would exercise its discretion to rescind them on those same grounds. Rescinding the applicability of the 2016 Rule requirements to methane emissions, while maintaining the applicability of those requirements to VOC emissions, will not affect the amount of methane reductions that those requirements will achieve, because the controls that reduce VOC emissions simultaneously reduce methane emissions.

Comments were received on both sides of this proposed decision and the rescission of the requirements for methane and the associated rationale. We respond to some of the major comments in the discussion immediately below and in section VIII.B of this preamble, and to the rest in Chapter 6 of the Response to Comments Document. None of the comments received have led the EPA to materially change its views from the proposal, and as a result, the EPA is rescinding the methane NSPS. The following is the rationale for this decision.

In the 2016 Rule, the EPA justified regulating methane for the following reasons: At the outset, the EPA noted that methane is a GHG, that the EPA has determined that GHG pollution endangers public health and welfare, and that the Crude Oil and Natural Gas Production source category is one of the nation's largest industrial emitters of methane. 81 FR 35825. The EPA also noted that ''[r]educing methane emissions . . . will contribute to efforts to reduce global background ozone concentrations that contribute to the incidence of ozone-related health effects.'' *Id.* at 35837. The EPA went on to determine that the amounts of emissions of methane from the source category were sufficiently large that it was rational to regulate them under CAA section 111, and that, in the alternative, assuming that it was necessary to determine that those emissions cause or contribute significantly to dangerous GHG air pollution, the EPA made that determination as well. *Id.* at 35841–43.

The EPA recognized that the controls that facilities use to meet the VOC NSPS ''also reduce methane emissions incidentally.'' *Id.* at 35841. However, the Agency added that ''in light of the current and projected future GHG emissions from the oil and natural gas industry, reducing GHG emissions from this source category should not be treated simply as an incidental benefit to VOC reduction; rather, it is something that should be directly addressed through GHG standards in the form of limits on methane emissions under CAA section 111(b) based on direct evaluation of the extent and impact of GHG emissions from this source category and the emission reductions that can be achieved through the best system for their reduction.'' *Id.* The Agency added, ''The standards detailed in this final action will achieve meaningful GHG reductions and will be an important step towards mitigating the impact of GHG emissions on climate change.'' *Id.*

The EPA further justified methane requirements by noting that ''there are cost-effective controls that can simultaneously reduce both methane and VOC emissions from these equipment across the industry, and in many instances, they are cost effective even if all the costs are attributed to methane reduction.'' *Id.* In addition, the EPA noted that ''establishing both GHG and VOC standards for equipment across the industry will also promote consistency by providing the same regulatory regime for this equipment throughout the oil and natural gas source category for both VOC and GHG, thereby facilitating implementation and enforcement.'' *Id.* The Agency added that, ''[w]hile this final rule will result in additional reductions [of GHG] . . ., the EPA often revises standards even where the revision will not lead to any additional reductions of a pollutant because another standard regulates a different pollutant using the same control equipment. For example, in 2014, the EPA revised the Kraft Pulp Mill NSPS in 40 CFR part 60 subpart BB published at 70 FR 18952 (April 4, 2014) to align the NSPS standards with the National Emission Standards for Hazardous Air Pollutants (NESHAP) standards for those sources in 40 CFR part 63, subpart S. Although no previously unregulated sources were added to the Kraft Pulp Mill NSPS, several emission limits were adjusted downward. The revised NSPS did not achieve additional reductions beyond those achieved by the NESHAP, but aligning the NSPS with the NESHAP eased the compliance burden for the sources.'' *Id.* n.60.

In *F.C.C.* v. *Fox Television Stations, Inc.,* 556 U.S. 502 (2009), the U.S. Supreme Court described the type of reasoning an agency must provide to justify changing a rule it has previously adopted:

> We find no basis in the Administrative Procedure Act or in our opinions for a requirement that all agency change be subjected to more searching review. The Act mentions no such heightened standard. And our opinion in *Motor Vehicle Mfrs. Assn. of United States, Inc.* v. *State Farm Mut. Automobile Ins. Co.,* 463 U.S. 29 (1983)

[35] Methane emissions from the transmission and storage segment are 34 MMT CO_2 Eq. (1,355 kt methane) per the Inventory of United States Greenhouse Gas Emissions and Sinks: 1990–2018 (published April 13, 2020), which amounts to 5 percent of United States methane emissions and 0.6 percent of total U.S. GHG emissions on a CO_2 equivalent basis (using a GWP of 25 for methane). With respect to VOC emissions, the transmission and storage segment emitted 14 kt in 2017, which amounts to just 5.8 percent of national VOC emissions from that year. With respect to SO_2 emissions, there were 1 kt emitted from the transmission and storage segment in 2017, or just 1.8 percent of national SO_2 emissions. For HAP emissions, the transmission and storage segment emitted 1,143 tons in 2014, or just 0.01 percent of national HAP emissions for that year.

neither held nor implied that every agency action representing a policy change must be justified by reasons more substantial than those required to adopt a policy in the first instance. . . . The statute makes no distinction, however, between initial agency action and subsequent agency action undoing or revising that action.

To be sure, the requirement that an agency provide reasoned explanation for its action would ordinarily demand that it display awareness that it *is* changing position. . . . And of course the agency must show that there are good reasons for the new policy. But it need not demonstrate to a court's satisfaction that the reasons for the new policy are *better* than the reasons for the old one; it suffices that the new policy is permissible under the statute, that there are good reasons for it, and that the agency *believes* it to be better, which the conscious change of course adequately indicates. This means that the agency need not always provide a more detailed justification than what would suffice for a new policy created on a blank slate. Sometimes it must—when, for example, its new policy rests upon factual findings that contradict those which underlay its prior policy; or when its prior policy has engendered serious reliance interests that must be taken into account. *Smiley* v. *Citibank (South Dakota), N. A.,* 517 U.S. 735, 742, 116 S.Ct. 1730, 135 L.Ed.2d 25 (1996). It would be arbitrary or capricious to ignore such matters. In such cases it is not that further justification is demanded by the mere fact of policy change; but that a reasoned explanation is needed for disregarding facts and circumstances that underlay or were engendered by the prior policy.

Id. at 514–16.

In the 2019 Proposal, the EPA acknowledged that in the 2016 Rule, it decided to add methane requirements even though it was aware that the VOC requirements would, by themselves, achieve the same reductions in methane. 84 FR 50259–60 and n.64 (citing 81 FR 35841). However, in that proposal, the EPA nevertheless stated that upon further review, it was proposing that it erred in 2016 by including methane requirements and explained that those requirements were redundant to the VOC requirements. *Id.* The EPA is finalizing this position for several reasons, which meet the requirements of *Fox Television* for reversing the 2016 Rule and rescinding the methane requirements.

In the 2016 Rule, the EPA justified regulating methane on grounds that methane emissions from this source category are great enough to provide a rational basis for regulation in light of the dangers of GHG air pollution and, in fact, if it were necessary, the Agency would determine that those emissions contribute significantly to GHG air pollution. However, in the present action, the EPA is determining that its rational basis finding and alternative SCF in the 2016 Rule were invalid because they included emissions from the transmission and storage segment, as discussed in section VI of this preamble. Accordingly, this basis [36] in the 2016 Rule for regulating methane is invalid.

Considering only the production and processing segments, the 2016 rational basis determination was incorrect because the methane NSPS was redundant on the grounds that it does not achieve any additional methane reductions beyond what sources achieve by implementing the VOC NSPS.[37] The EPA explained its basis for this view at length in the 2019 Proposal, noting that ''for each emission source in the source category subject to the NSPS, the requirements overlap completely.'' 84 FR 50259. The EPA explained that each emission source in the source category emits methane and VOC as co-pollutants through the same emission points and processes. The requirements of the NSPS, including the emission limits, required controls or changes in operations, monitoring, recordkeeping, reporting, and all other requirements, apply to each emission source's emission points and processes and, therefore, to each emission source's methane and VOC emissions, in precisely the same way. The capture and control devices used to meet the NSPS requirements are the same for these co-pollutants and are not selective with respect to either VOC or methane emissions. *Id.* In the proposal, the EPA gave several examples of how the VOC and methane requirements are duplicative of each other. Some examples include the requirements for well affected facilities, pneumatic controllers, pneumatic pumps, and compressors. For each of these emission points, the applicability requirements in NSPS subpart OOOOa are entirely ''pollutant-blind.'' That is, the requirement to control is based on applicability criteria that are not specific to VOC. For example, a pneumatic controller affected facility is a controller operating at a natural gas bleed rate of greater than 6 standard cubic feet per hour (scfh). The ''natural gas'' bleed rate is based on total gas and does not consider the amount of VOC in the gas. In fact, the VOC content could be zero. Similarly, pneumatic pumps are affected facilities if they are ''natural gas driven.'' All reciprocating and wet-sealed compressors, except those at well sites, are affected facilities. Rescission of the methane standards will have no impact on the number of affected facilities that will be subject to the control requirements in NSPS subpart OOOOa. Further, for well completions, pneumatic controllers, reciprocating compressors, and pneumatic pumps at natural gas processing plants, the control requirements are either equipment standards or work practices that do not distinguish between VOC and methane. For pneumatic pumps, the requirement is a 95-percent reduction in ''natural gas emissions.'' Finally, for wet-sealed centrifugal compressors, the requirement is the only one that specifically mentions VOC or methane, as it requires a 95-percent reduction in VOC and methane. However, removal of ''methane'' will not result in any change in methane reduction as the test method required to demonstrate this level of reduction (EPA Method 25A) measures the reduction of total organic carbon, which includes methane.

Thus, after the rescission of the methane standards, there will be no change in the number of affected facilities subject to the rule. There will also be no impact in the methane emission reductions achieved from those sources. While commenters recognized this fact, some raised concerns that in the future, advances in leak measurement technology may result in situations where VOC and methane controls are not redundant. The EPA points out that any future request for an alternative means of emissions limitation must include a demonstration that the alternative identifies emissions for repair that are at least equivalent to the visible emissions observed (and repaired) using optical gas imaging (OGI) with the current levels of sensitivity to methane, especially where the technology speciates emissions. Section VIII.B of this preamble, as well as Chapter 6 of the Response to Comments Document, includes comments and responses on this topic. Because methane reductions occur anyway as a result of the same controls required under the VOC requirements, the benefits of the methane reductions in protecting public health or welfare do not justify regulation of methane under CAA section 111. By the same token, the fact that the controls are cost effective—even, in many cases, when all of the costs are assigned to the methane requirements—does not justify those requirements. Again, the controls, imposed to reduce VOC, would result in the same amount of methane reductions, even without the methane requirements.

Nor can the methane requirements be justified on grounds that their overlap with VOC requirements is a means to

[36] 81 FR 35833.

[37] The same is true for methane reductions that reduce global ozone levels.

promote consistency by providing the same regulatory regime for this equipment throughout the Oil and Natural Gas source category for both VOC and methane, thereby facilitating implementation and enforcement. Although, as noted above, the EPA regulates the same sources/same pollutants at kraft mills under two differing rules, the requirements were established under two different CAA regulatory programs (*i.e.,* under CAA sections 111 and 112) (two different regulatory regimes). The pollutants regulated under CAA section 111(b) for new, modified, or reconstructed emission units at kraft pulp mills are filterable PM and total reduced sulfur compounds. Opacity is regulated to ensure proper operation and maintenance of the electrostatic precipitator used to control PM emissions. Particulate matter emissions and opacity are also regulated under a separate Federal standard, the subpart MM NESHAP for chemical recovery combustion sources at kraft, soda, sulfite, and stand-alone semichemical pulp mills (40 CFR part 63).

It is rational for the EPA to determine that requirements that are redundant to other requirements are not necessary because they do not result in emission reductions beyond what would otherwise occur. As the EPA noted in the 2019 Proposal, the rulemaking to promulgate NSPS for lime manufacturing plants provides another example of the Agency determining not to promulgate a NSPS for an air pollutant, SO_2, on grounds that the emissions were adequately controlled by emissions controls required under a NSPS for another air pollutant, PM. Standards of Performance for New Stationary Sources Lime Manufacturing Plants, 42 FR 22506 (May 3, 1977). Although in that rulemaking, the EPA did not explicitly state that SO_2 controls would have been redundant and, thus, were unnecessary, the Agency's reasoning was fully consistent with that characterization. Specifically, the EPA noted that the controls it was requiring for PM (a baghouse or an electrostatic precipitator) would achieve 85- to 90-percent reductions in SO_2, and that although the EPA could impose further controls to achieve another 7 percent reduction in SO_2, based on the use of a scrubber, the cost would be too high and the environmental benefits too little for that approach to be appropriate. *Id.* at 22507. Accordingly, the EPA prescribed standards for PM but not for SO_2. *Id.* at 22509 (40 CFR 60.342). That is, it appears that the EPA could have promulgated standards for SO_2 that required the same 85- to 90-percent level of control achieved through compliance with the PM standards (and not the additional 7 percent that would have necessitated installation of a scrubber), but the Agency declined to do so. Even though the EPA did not explicitly describe the potential SO_2 NSPS as redundant and, therefore, unnecessary, the fact that it did not promulgate any standards for SO_2 coupled with its explanation that PM controls reduced SO_2 by 85 to 90 percent make clear that the rulemaking serves as a precedent for the present rulemaking and the Agency's present position that the methane NSPS is redundant to the VOC NSPS. By the same token, in the Lime Manufacturing Plants rule, the EPA declined to promulgate NSPS for (1) nitrogen oxides (NO_X) because they are emitted in low concentrations or (2) CO because, among other things, regulation would produce little environmental benefit. *Id.* at 22507. These rationales for not adopting controls for those air pollutants are similar to the redundancy rationale—the essential point in all cases is that any controls would not result in meaningful emission reductions.

In a more recent rulemaking, under the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), the EPA also declined to promulgate requirements that it considered to be redundant, and the Court upheld that action. Under 42 U.S.C. 9608(b)(1), the EPA is required to ''promulgate requirements . . . that classes of facilities establish and maintain evidence of financial responsibility consistent with the degree and duration of risk associated with the production, transportation, treatment, storage, or disposal of hazardous substances.'' In 2018, the EPA took an action in which it declined to issue financial responsibility regulations for the hardrock mining industry. Financial Responsibility Requirements Under CERCLA Section 108(b) for Classes of Facilities in the Hardrock Mining Industry (Final Action), 83 FR 7556, 7556 (February 21, 2018). As summarized by the Court, the EPA stated that ''existing federal and state programs as well as modern mining practices reduced the risk that the EPA would be required to use the Superfund to finance response actions at currently active mines.'' *Idaho Conservation League* v. *Wheeler,* 930 F.3d 494, 501 (D.C. Cir. 2019) (citing 83 FR 7556). The Court upheld that determination, stating that 42 U.S.C. 9608(b)(1) ''does not place any obligation on the EPA to issue redundant financial responsibility requirements.'' *Id.* at 504–5.[38] [39]

One commenter cites two Court cases that it asserts support the view that the EPA must regulate a source's emissions of a particular pollutant under CAA section 111 even where the source already controls those emissions because of other legal obligations. In *New York* v. *Reilly,* 969 F.2d 1147, 1153 (D.C. Cir. 1992), the Court rejected the EPA's argument that it need not ban the burning of lead-acid vehicle batteries under the NSPS for municipal waste combustors because the Resource Conservation and Recovery Act precludes the burning of lead-acid batteries. The Court responded that ''the mere existence of other statutory authority which might undergird EPA's final stance is insufficient to justify the omission of the battery ban.'' In *Portland Cement Ass'n* v. *EPA,* 665 F.3d 177, 191 (D.C. Cir. 2011), the Court rejected legal challenges to an NSPS limit for PM that tracked a concurrently issued PM standard adopted under CAA section 112. The Court explained that, ''[a]lthough both the NSPS and NESHAP rulemaking resulted in a PM emissions limit of 0.01 pounds per ton, EPA arrived at that limit using two different mechanisms,'' and added that ''the final rule . . . noted that kilns would have to install fabric filter technology to comply

[38] In addition, as the EPA noted in the 2019 Proposal, it ''ha[s] 'historically declined to propose standards for a pollutant [that] is emit[ted] in low amounts . . . .' '' 80 FR 56599 (quoting 75 FR 54970, 54997 (September 9, 2010). This situation is similar to the present situation in which a pollutant (methane) is fully controlled by requirements applicable to a second pollutant (VOC).

[39] The EPA notes that removing the applicability of the NSPS to methane emissions does not alter the basis for the applicability of the NSPS to VOC emissions for affected sources in the source category, which for some affected sources have been regulated since the 2012 Rule. To determine the best system of emission reduction (BSER), the EPA assesses a set of factors, which include the amount of emissions reduction, costs, energy requirements, non-air quality impacts, and the advancement of particular types of technology or other means of reducing emissions, and retains discretion to weight the factors differently in any case. In the 2016 NSPS subpart OOOOa, the EPA gave primary weight to the amount of emission reductions and cost. The EPA describes this analysis in depth in the 2015 NSPS subpart OOOOa proposal at 80 FR 56618 through 56620 and 80 FR 56625 through 56627. For the source types in the production and processing segments, the NSPS requirements, considered on a VOC-only basis, are cost effective (relatively low cost and relatively high emissions reductions). *See* memorandum titled ''Control Cost and Emission Changes under the Amendments to 40 CFR part 60, subpart OOOOa Under Executive Order 13783,'' in the public docket for this action. The EPA provides this information for the benefit of the public and is not reopening the above-described determination in the 2016 NSPS subpart OOOOa that the VOC-only requirements for sources in the production and processing segments meet the requirements of CAA section 111.

with NESHAP, . . . and the parallel NSPS rule would therefore have no additional cost.'' The commenter states that, similarly, while the EPA set the same BSER for methane and VOC in the 2016 Rule, the considerations underlying the BSER analysis differs significantly for these pollutants, which cause distinct harms. However, these cases are distinguishable because they stand for the proposition that when two separate statutory requirements apply, each must be given effect, and compliance with one does not obviate the other. In the present rulemaking, only one statutory requirement is applicable—the CAA section 111(b)(1)(B) requirement to promulgate standards of performance—and the EPA has determined that promulgating a standard of performance for VOC emissions obviates the need for a standard of performance for methane emissions from the same sources. Further, as the EPA noted in the 2019 Proposal, the EPA has historically declined to propose standards for a pollutant that is emitted in small amounts. 84 FR 50260. In the case of the Oil and Natural Gas Production source category, there are no methane emissions from the sources subject to the NSPS beyond those emissions already subject to control by the provisions to control VOC in the NSPS. Accordingly, there is no need to add NSPS requirements applicable to methane.

The EPA recognizes that in rescinding one set of standards in part for its redundancy with another set, the EPA is choosing to rescind the applicability of those standards to methane emissions and not VOC emissions, rather than vice-versa. Rescinding the methane-specific standards is reasonable because the requirements for VOC and correspondingly, sources' compliance with those requirements, are longer established than those for methane. As described earlier, the EPA regulated VOC first, beginning in 1985 and continuing in 2012, and then added regulation of methane for some sources in 2016.

Additionally, redundancy is not uniform across affected facilities in the production and processing segments. All sources in the segments are subject to VOC requirements and many are subject to methane requirements as well. However, some sources, such as storage vessels, are subject only to VOC requirements and not methane requirements. For those sources, it cannot be said that regulation of VOC is redundant to regulation of methane because the EPA has not regulated methane from them. In addition, there are no sources that are subject to only methane requirements. For these reasons, in choosing between the two requirements, the EPA considers it appropriate and less disruptive to rescind the methane standards.

Commenters asserted that the methane NSPS are not redundant to the VOC NSPS because the former trigger the requirements in CAA section 111(d) to regulate methane from existing sources, but the VOC NSPS do not trigger CAA section 111(d) requirements to regulate VOC from existing sources. The commenters noted that the EPA must consider emissions from existing sources when determining whether to list the source category, which is the predicate to regulating a given pollutant under CAA section 111.

The commenters are correct that methane NSPS, but not VOC NSPS, would trigger the CAA section 111(d) requirements for existing sources,[40] but the fact that the methane NSPS carries with it a trigger for CAA section 111(d) regulation of existing sources is simply a legal consequence of the requirements of CAA section 111, and does not undermine the EPA's conclusion that methane NSPS are redundant. Nor does the fact that the EPA considers emissions from existing sources in listing the source category. These conclusions are supported by the structure of CAA section 111. This provision establishes a multi-step process for regulation. Section 111(b)(1)(A) of the CAA directs the EPA to list source categories for regulation, CAA section 111(b)(1)(B) directs the EPA then to promulgate standards of performance for pollutants emitted from new sources, and CAA section 111(d)(1) directs the EPA then to promulgate guidelines for states to adopt standards of performance for certain of those pollutants emitted by existing sources. As explained above and in responses to comments, the basis for rescinding the applicability of the standards of performance for methane emissions is that those NSPS are redundant with the VOC NSPS. The legal consequence of that rescission is that the EPA is not authorized to promulgate CAA section 111(d) guidelines for existing sources. That consequence does not negate the fact that the methane NSPS is redundant with the VOC NSPS.

As discussed in section VII.B of this preamble, the EPA believes that the impact of not regulating existing oil and natural gas sources under CAA section 111(d) will be limited due to existing factors that encourage or require control of emissions from oil and natural gas existing sources. For comments on that view, and the EPA's response to those comments, see section X.B of this preamble.

Additional comments and responses by the EPA on the rescission of the applicability to methane are provided in section VIII.B of this preamble and in Chapter 6 of the Response to Comments Document.

In the next section, the EPA concludes that the 2016 Rule's determination that methane emissions from the source category contribute significantly to dangerous air pollution was erroneous and must be rescinded. Rescinding that determination also requires rescinding the methane NSPS. The redundancy of the methane requirements and the inadequacy of the 2016 Rule's SCF for methane are separate and independent reasons for rescinding the methane NSPS, and, thus, are severable from each other.

VI. Significant Contribution

The EPA is finalizing the position that the Administrator is required to determine that methane emissions from the Crude Oil and Natural Gas Production source category cause or contribute significantly to GHG air pollution as a predicate for promulgating standards of performance for methane. The EPA solicited comment on this position in the 2019 Proposal, based on an interpretation of section 111 of the CAA, and the EPA bases this final action on a refinement of that interpretation. Specifically, the EPA interprets the requirement of CAA section 111(b)(1)(B) that the Administrator propose to ''establish[ ] . . . standards of performance'' and then finalize ''such standards''—together with the CAA section 111(a)(1) definition of ''standard of performance'' as a ''standard for emissions of air pollutants''—to limit the standards of performance to only those air pollutants that the Administrator determined cause or contribute significantly to dangerous air pollution when listing the source category under CAA section 111(b)(1)(A). If the Administrator did not, when listing the source category, determine that a particular air pollutant causes or contributes significantly to dangerous air pollution, then the Administrator must do so as a predicate to promulgating standards of performance for that air pollutant.

Section VI.A of this preamble, immediately below, discusses that interpretation of CAA section 111. In section VI.B of this preamble, we explain how this interpretation applies

[40] In section VII below, we finalize our proposal that VOC NSPS do not trigger CAA section 111(d) requirements.

to the regulation of methane from the Crude Oil and Natural Gas Production source category. In section VI.C of this preamble, we briefly discuss criteria for making a SCF under CAA section 111.

A. Legal Interpretation Concerning the Air Pollutants That Are Subject to CAA Section 111

1. 2019 Proposal

As noted above, CAA section 111 establishes a process for the EPA to regulate air pollutants from industrial source categories. Section 111(b)(1)(A) of the CAA requires the first step: the Administrator must list a particular category of stationary sources that ''causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare,'' and then, under CAA section 111(b)(1)(B), the Administrator must proceed to promulgate standards of performance for that source category. For convenience, we refer to ''air pollution which may reasonably be anticipated to endanger public health or welfare'' as dangerous air pollution, and we refer to the reference to ''causes or contributes significantly'' as the SCF. In the 2019 Proposal, we solicited comment on whether CAA section 111(b)(1)(A) must be read, or reasonably could be read, to require the Administrator to make not only a SCF to list the source category, but also a SCF for a particular air pollutant as a predicate to promulgating a standard of performance for that pollutant under CAA section 111(b)(1)(B).

The EPA supported this interpretation with a detailed discussion of the relevant statutory provisions, their context, and purpose, as well as past administrative practice. At the outset, the EPA acknowledged that CAA section 111(b)(1)(A) by its terms requires that the Administrator make a SCF for the source category, and is silent on individual air pollutants.[41] However, the EPA noted that CAA section 111(b)(1)(A) should be read in conjunction with CAA sections 111(b)(1)(B) and 111(a)(1), which require the Administrator to promulgate ''standards of performance,'' defined as ''standard[s] for emissions of air pollutants.'' The EPA posited that those provisions, read together, by virtue of their focus on emissions of air pollutants, could be interpreted to require or authorize the EPA to require a pollutant-specific SCF as a predicate for promulgating a standard of performance. 84 FR 50263. The EPA acknowledged that in the past it has not promulgated a pollutant-specific SCF, and instead has taken the position that it may promulgate a standard of performance for a pollutant not previously regulated under CAA section 111 as long as it simply has a rational basis for doing so. In the 2019 Proposal, the EPA explained that this approach is flawed because it is vague and not guided by any statutory criteria, and that as a result, it could result in the Agency promulgating standards for air pollutants that are emitted in relatively minor amounts. 84 FR 50263. The Agency stated that interpreting CAA section 111 to require a pollutant-specific SCF as a predicate to regulating the pollutant would guard against this possibility.[42]

2. Comments

The EPA received comment on all aspects of its solicitation of comment. Some commenters supported the EPA's arguments and urged the Agency to finalize an interpretation that requires the Administrator to make a pollutant-specific SCF as a predicate to promulgating standards of performance for that pollutant from a source category. Other commenters opposed this interpretation and sought to counter the support for it that the EPA offered. They argued that under CAA section 111(b)(1)(A), the SCF applies only to source categories. They further argued that the references in CAA sections 111(b)(1)(B) and 111(a)(1) to air pollutants are unremarkable because standards of performance necessarily apply to particular air pollutants, and should not be read to elucidate the meaning of CAA section 111(b)(1)(A) in the manner the EPA suggested.[43] These comments are discussed in more detail in section IX of this preamble and in Chapter 8 of the Response to Comments Document located in the docket for this rulemaking.

3. Final Action

The EPA is finalizing the position that CAA section 111 requires, or at least authorizes the Administrator to require a pollutant-specific SCF as a predicate for promulgating a standard of performance for that air pollutant. The EPA bases this position primarily on a refinement of the interpretation of CAA section 111, described above, on which it solicited comment. Specifically, the EPA interprets the CAA section 111(b)(1)(B) requirement that the Administrator propose to ''establish[ ] . . . standards of performance'' and then finalize ''such standards with such modifications as he deems appropriate,'' in light of both the CAA section 111(a)(1) definition of ''standard of performance'' as a ''standard for emissions of air pollutants,'' and CAA section 111(b)(1)(A), which requires the Administrator to list a source category only ''if in his judgment it causes, or contributes significantly to [dangerous] air pollution.'' Read in this context, CAA section 111(b)(1)(B) is best understood *not* to require the Administrator to promulgate standards for emissions of *all* air pollutants but only to require him or her to promulgate standards for the emissions of air pollutants that the Administrator has determined ''cause or contribute significantly'' to the ''air pollution'' that the Administrator determined to be dangerous when listing the source category. Under this interpretation, if the Administrator did not, in listing the source category, determine that a particular air pollutant causes or contributes significantly to the dangerous air pollution, section 111 requires the Administrator to make—or, at least, authorizes the Administrator to require—a pollutant-specific SCF as a predicate to regulating that air pollutant.[44]

[41] It should be noted that even though CAA section 111(b)(1)(A) is clear in requiring a SCF for the source category, its silence as to individual air pollutants, which of course are what causes or contributes significantly to dangerous air pollution and are the subject of regulation, leaves to the EPA the task of addressing individual air pollutants.

[42] The EPA went on to review other provisions in the CAA that explicitly require a pollutant-specific SCF; the legislative history accompanying these provisions; the references in another CAA section 111 provision, CAA section 111(f)(2)(A) and (B), to the impacts of particular pollutants on dangerous air pollution; and previous interpretations that the EPA had made of the CAA section 111 requirements concerning individual air pollutants. 84 FR 50263–67.

[43] The commenters objected to the EPA's interpretation of other CAA provisions, of legislative history, and of other provisions of CAA section 111, as well as the EPA's interpretations of CAA section 111 in earlier administrative actions. We discuss these comments in the Response to Comments Document located in the public docket of this final rulemaking.

[44] Although this interpretation is a refinement of the interpretation for which the EPA solicited comment in the 2019 Proposal, it is rooted in the Proposal. As noted in the summary above, in supporting the interpretation that CAA section 111(b)(1)(A) requires or authorizes the EPA to require a pollutant-specific SCF, the EPA made numerous references to CAA sections 111(a)(1) and 111(b)(1)(B), and made clear that those three provisions must be read together. The EPA made other references as well to the need to make a pollutant-specific SCF in order to promulgate standards of performance, which is the thrust of the interpretation described in this final action. *See Id.* at 50262–63. The rational basis approach was an interpretation of CAA section 111(b)(1)(B). That is, under this approach, the EPA interpreted that provision to authorize standards of performance for those air pollutants for which the EPA had a rational basis, but not necessarily standards for all air pollutants. *See* 81 FR 35842 (2016 Rule), *cited*

4. Legal Interpretation of CAA Sections 111(a)(1), (b)(1)(B), and (b)(1)(A) and the Pollutants Subject to Regulation

The EPA interprets CAA sections 111(b)(1)(B), in light of CAA sections (b)(1)(A) and (a)(1), to require, or at least to authorize the Administrator to require, a pollutant-specific SCF as a predicate for promulgating a standard of performance for that air pollutant. The EPA bases this interpretation on a close reading of these provisions in the context of CAA section 111. CAA section 111 directs the EPA to regulate, through a multi-step process, air pollutants from categories of stationary sources. CAA section 111(b)(1)(A) requires the initial action, which is that the Administrator must ''publish . . . a list of categories of stationary sources. He shall include a category of sources in such list if in his judgment it causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare.'' This provision does not by its terms require the Administrator, in listing a source category, to identify particular air pollutants of concern that are emitted from the source category, but it does make clear that the Administrator must identify air pollution that is of concern and must make a finding that this air pollution, in our shorthand, is dangerous.

CAA section 111(b)(1)(B) then directs the EPA to propose regulations ''establishing Federal standards of performance'' for new sources within the source category, then to allow public comment, and then to ''promulgate . . . such standards with such modifications as he deems appropriate.'' CAA section 111(a)(1) defines the term ''standard of performance'' as ''a standard for emissions of air pollutants which [the Administrator is required to determine through a specified methodology].'' This definition makes clear that the standards of performance that CAA section 111(b)(1)(A) directs the Administrator to promulgate must concern air pollutants emitted from the sources in the source category. However, industrial sources of the type subject to CAA section 111(b)(1)(A) invariably emit more than one air pollutant and neither CAA section 111(b)(1)(B) nor 111(a)(1) by its terms specifies for which of those air pollutants the EPA must promulgate standards of performance.

But the statute does provide guidance as to the class of air pollutants for which the EPA must promulgate standards of performance. Section 111(b)(1)(A) of the CAA demonstrates that the statutory scheme of CAA section 111 is aimed at controlling ''air pollution which may reasonably be anticipated to endanger public health or welfare.'' It follows that the air pollutants for which the Administrator must establish standards must, or at least may reasonably, be limited to those air pollutants which contribute to this dangerous air pollution.

The Administrator's discretion to limit the class of air pollutants for which he promulgates standards is supported by his statutory discretion under CAA section 111(b)(1)(B) to finalize standards ''with such modifications as he deems appropriate.'' In an exercise of this discretion, the Administrator deems it appropriate to limit the standards of performance to those air pollutants that contribute to dangerous air pollution.

Several other provisions in CAA section 111 also refer to air pollutants, including CAA section 111(b)(3), which requires the Administrator to, ''from time to time, issue information on pollution control techniques for categories of new sources and air pollutants subject to the provisions of this section.'' This reference to ''air pollutants *subject to the provisions of this section*'' (emphasis added) implies that some air pollutants may not be subject to CAA section 111; otherwise, the emphasized phrase would be superfluous.[45]

As noted in the 2019 Proposal, in the past, the EPA has interpreted CAA section 111(b)(1)(B) to authorize it to promulgate standards of performance for any air pollutant that the EPA identified in listing the source category and any additional air pollutant for which the EPA has identified a rational basis for regulation. 81 FR 35843 (2016 Oil & Gas Methane Rule); ''Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units—Final Rule,'' 80 FR 64510 (October 23, 2015) (EGU CO_2 NSPS Rule). Inherent in this approach is the recognition that CAA section 111(b)(1)(A) does not, by its terms, necessarily require the EPA to promulgate standards of performance for all air pollutants emitting from the source category. Citizen group stakeholders and some states have endorsed the rational basis approach. Some industry stakeholders and other states, however, have advocated a narrower approach with respect to, at least, the GHG for which the EPA promulgated standards of performance for the Fossil Fuel-Fired Electric Utility Generating Units source category and the Crude Oil and Natural Gas Production source category. The stakeholders argued that under this narrower approach, the EPA is not authorized to promulgate NSPS for at least GHG unless it first makes a SCF with respect to that pollutant.

The EPA interprets the phrase at issue in CAA section 111(b)(1)(B), ''standards of performance,'' and the associated phrase in CAA section 111(a)(1), ''emissions of air pollutants,'' by analogy to the similar phrase, ''any air pollutant,'' found in the CAA permitting provisions that the U.S. Supreme Court considered in *Utility Air Regulatory Group* v. *EPA,* 573 U.S. 302 (2014) (*UARG*). In *UARG,* the Court interpreted CAA section 169(1), which provides construction and modification permitting requirements under the Prevention of Significant Deterioration (PSD) program, and CAA sections 501(2)(B) and 302(j), which provide the operating permit requirements of the title V program. The Court concluded that when read in the context of the permitting provisions, the phrase ''any air pollutant'' did not encompass GHG, even though they are air pollutants. The EPA considers that the analytical approach that the Court adopted in *UARG* also applies to CAA section 111(b)(1)(B). Under this approach, the provisions in that section that direct the Administrator to establish ''standards of performance'' for new sources in the source category, require, or at least reasonably allow, the Administrator to promulgate standards for only those air pollutants for which the EPA has made a SCF.

The EPA considers the same analytical approach to support interpreting ''emissions of air pollutants'' in CAA section 111(a)(1) to encompass only those air pollutants for which the EPA has made a SCF. Under the PSD requirements, no ''major emitting facility'' may be constructed or

in 84 FR 50262 (2019 Proposal). This approach is similar to the pollutant-specific SCF approach. By the same token, the EPA's discussions in the 2019 Proposal of the legislative history, CAA section 111(f), and previous statements the EPA made in support documents all contain references to a pollutant-specific SCF as a predicate for promulgating standards of performance. 84 FR 50263 through 67.

[45] Similarly, CAA section 111(d)(1)(A) makes clear by its terms that ''a standard of performance under this section'' need not govern *all* pollutants emitted from a regulated source to give effect to Congress's purpose. The requirements of CAA section 111(d)(1)(A) apply to only a subset of air pollutants, that is, ''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 but . . . to which a standard of performance under this section would apply if such existing source were a new source.''

modified in certain areas of the U.S. unless it has received a permit that includes certain conditions and emission limits. CAA section 165(a)(1). In the PSD definitional provisions, CAA section 169(1) defines the term ''major emitting facility'' as any stationary source of air pollutants that emits, or has the potential to emit, at least 100 or 250 tpy (depending on the source) of ''any air pollutant.'' *See* CAA sections 169(2)(C), 111(a)(4) (defining ''construction'' to include ''modification,'' which in turn is defined to mean, in relevant part, a certain type of change that increases the amount of ''any air pollutant'' emitted by the source). Title V makes it unlawful to operate a ''major source'' without an operating permit that includes all applicable CAA requirements. Title V defines a ''major source'' by incorporating the CAA-wide definition of ''major stationary source:'' A stationary source that emits or has the potential to emit at least 100 tons per year of ''any air pollutant.'' CAA section 501(2)(B), 302(j).

In a 2010 rule, ''Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule,'' 75 FR 31514 (June 3, 2010) (Tailoring Rule), the EPA took the position that the phrase ''any air pollutant'' in these provisions necessarily included GHG, based on the 2007 decision by the U.S. Supreme Court that the CAA-wide definition of ''air pollutant,'' CAA section 302(g), encompasses GHG. *Massachusetts* v. *EPA,* 549 U.S. 497 (2007). The EPA's interpretation, however, created practical problems, which the Agency recognized in the Tailoring Rule: It would cause numerous commercial and small industrial sources to become subject to the permitting requirements, which were burdensome and which Congress designed to apply only to large industrial sources that were equipped to carry those burdens. *UARG,* 573 U.S. at 310–11 (citing 73 FR 44355, 44498 and 99).

UARG held that the EPA's interpretation of the PSD and title V provisions was unreasonable, and that the phrase ''any air pollutant'' in these provisions did not include GHG. The Court adopted a two-step analysis. First, the Court found that the fact that the CAA-wide definition of ''air pollutant'' included GHG did not mean that all the references to ''air pollutant'' in the CAA's operative provisions necessarily include GHG; rather, whether the term included GHG was dependent on the context of the particular operative provision. 573 U.S. at 316. The Court found support for this position in the fact that ''where the term 'air pollutant' appears in the Act's operative provisions, EPA has routinely given it a narrower, context-appropriate meaning.'' *Id.* The Court explained that the EPA had already interpreted ''any air pollutant'' in the permitting provisions to be limited to ''regulated'' air pollutants, which the Court described as ''a reasonable, context-appropriate meaning.'' *Id.* at 316–17. The Court identified several other provisions ''where EPA has inferred from statutory context that a generic reference to air pollutants does not encompass every substance falling within the Act-wide definition.'' For example, and of particular significance here, the Court noted that CAA section 111(a)(4), read together with CAA sections 111(a)(2) and (b)(1)(B), applies NSPS requirements to a source that undergoes a physical or operational change that increases its emission of ''any air pollutant,'' but the EPA interprets this provision as limited to air pollutants for which the EPA has promulgated standards of performance. 573 U.S. at 317. Similarly, the Court noted that CAA sections 169A(b)(2)(A) and (g)(7) require a certain type of source that interferes with visibility to retrofit if it has the potential to emit 250 tpy of ''any pollutant,'' but that the EPA interprets this provision as limited to visibility-impairing air pollutants. 573 U.S. at 318. The Court emphasized that *Massachusetts* did not call these interpretations into question; rather, according to the Court, ''*Massachusetts* does not foreclose the Agency's use of statutory context to infer that certain of the Act's provisions use 'air pollutant' to denote not every conceivable airborne substance, but only those that may sensibly be encompassed within the particular regulatory program.'' 573 U.S. at 319. Therefore, in this first step, the Court concluded that the CAA did not compel the EPA to interpret the phrase ''any air pollutant'' in the permitting provisions to include GHG.

Second, the Court found that the EPA did not have the discretion to interpret this phrase to include GHG, because it was unreasonable to do so in light of the permitting provisions. The Court explained that including GHG would expand the permitting programs to large numbers of small sources, but that ''a brief review of the relevant statutory provisions leaves no doubt that the PSD program and Title V are designed to apply to, and cannot rationally be extended beyond, a relative handful of large sources capable of shouldering heavy substantive and procedural burdens.'' *Id.* at 322. The Court went on to describe the various PSD and title V statutory requirements that are resource-intensive and time-consuming, and, therefore, incompatible with application to large numbers of small sources. *Id.* at 322–23.

The EPA is adopting *UARG's* two-step analytical approach to conclude that, in light of its context, CAA section 111(b)(1)(B) does not mandate, and cannot reasonably be read to authorize, the EPA to promulgate standards of performance for an air pollutant for which the EPA has not made a SCF. At a minimum, even if these provisions are not read to preclude the EPA from promulgating standards of performance without first making a pollutant-specific SCF, it is reasonable to interpret these provisions as authorizing the EPA to decline to promulgate standards without first making such a SCF. *UARG* was explicit that provisions of CAA section 111 are subject to its analytical approach. As noted above, the Court endorsed the EPA's interpretation that, notwithstanding the reference to ''any air pollutant'' in CAA section 111(a)(4), the requirements concerning a ''modification'' in CAA section 111(b)(1)(B), which is at issue here, and CAA sections 111(a)(2) and (4) do not require the EPA to promulgate standards for every pollutant that a modified source emits, because those provisions must be understood in context to embrace a limited set of air pollutants. 573 U.S. at 317.

As is clear from the EPA's summary above of the CAA section 111 rulemaking process, the first action that the EPA must take, specified in CAA section 111(b)(1)(A), is to list a source category for regulation on the basis of a determination that the category contributes significantly to dangerous air pollution, and it is this provision that establishes the context that is relevant for present purposes. This provision makes clear that although Congress designed CAA section 111 to apply broadly to source categories of all types wherever located, Congress also imposed a constraint: The EPA is authorized to regulate only sources that it finds cause or contribute significantly to air pollution that the EPA finds to be dangerous.

Congress' direction to EPA to promulgate standards of performance for the sources in the category, under CAA section 111(b)(1)(B), must be viewed in this context. Congress did not specify which air pollutants the standards of performance must address, stating only, as noted above, in the definitional provisions of CAA section 111 that the term ''standard of performance'' means a standard for ''emissions of air pollutants.'' This phrase is substantially similar to the phrase ''any air pollutant'' in the PSD and Title V provisions addressed in *UARG.* In fact, ''emissions of air pollutants'' appears to be less encompassing than ''any air pollutant.'' As the U.S. Supreme Court has noted, ''Read naturally, the word 'any' has an expansive meaning, that is, 'one or some indiscriminately of whatever kind.' Webster's Third New International Dictionary 97 (1976).'' *United States* v. *Gonzales,* 520 U.S. 1, 4, 1997), *quoted in Department of Housing and Urban Development* v. *Rucker,* 535 U.S. 125, 131 (2002), *cited in Massachusetts,* 549 U.S. at 529 n.25.

Under the analytical approach of *UARG,* because the regulatory scope of the CAA's ''operative provisions,'' such as CAA sections 111(b)(1)(B) and 111(a)(1), must be understood in context, their reference to ''standards of performance'' and ''emissions of air pollutants'' cannot be read to mandate promulgation of standards of performance for each and every air pollutant emitted from the source category. In addition, because Congress limited the EPA to regulating only stationary sources in a category that the Administrator must first determine to cause or contribute significantly to dangerous air pollution, it is not reasonable to read ''air pollutants'' to refer to any of the source category's air pollutants for which the EPA has not made a SCF. At the very least, it is reasonable to interpret that phrase more narrowly. As noted in the 2019 Proposal, interpreting the CAA section 111 provisions to authorize the EPA to regulate any air pollutant, even ones that the EPA did not consider in listing the source category, creates the risk that the EPA may regulate air pollutants emitted in small quantities or otherwise having little adverse effect.[46]

It is true that, recently, the EPA has adopted the approach of regulating additional air pollutants that it did not address in the listing determination only after determining that it has a rational basis for doing so, and in making that determination, has considered the same factors as it would in making a SCF. 81 FR 35843 (2016 Rule). However, this approach is a creature of Agency practice and, therefore, is not as firmly established as statutory requirements. As noted in the 2019 Proposal, interpreting CAA section 111 to require only a pollutant-specific rational basis standard, and not a SCF, could lead to potentially anomalous results when the Agency, after listing a source category on grounds that its emissions taken together contribute significantly to dangerous air pollution, proceeds to promulgate NSPS for individual air pollutants. EPA stated that, as an example, under the rational basis interpretation, the EPA could list a source category on grounds that it emits numerous air pollutants that, taken together, significantly contribute to air pollution that may reasonably be anticipated to endanger public health or welfare, and proceed to regulate each of those pollutants, without ever finding that each (or any) of those air pollutants by itself causes or contributes significantly to—or, in terms of the text of other provisions, causes or contributes to—air pollution that may reasonably be anticipated to endanger public health or welfare. 84 FR 50263. As further noted in the 2019 Proposal, CAA section 111(b)(1)(A) does not provide or suggest any criteria to define the rational basis approach, the EPA has not articulated any criteria in its previous applications in the EGU CO_2 NSPS and the 2016 subpart OOOOa rules, and in instances before those rules in which the EPA has relied on the ''rational basis'' approach, the EPA has done so to justify not setting a standard for a given pollutant, rather than to justify setting such a standard. *Id.* Thus, the rational basis test allows the EPA virtually unfettered discretion in determining which air pollutants to regulate. As a result, the rational basis standard creates the possibility that the EPA could seek to promulgate NSPS for pollutants that may be emitted in relatively minor amounts, as the EPA noted in the 2019 Proposal. 84 FR 50263. As noted in section IX below, numerous commenters reiterated these concerns.

In contrast, CAA section 111(b)(1)(A) is clear that the EPA may list a source category for regulation only if the EPA determines that the source category ''causes or contributes *significantly*'' (emphasis added) to dangerous air pollution. In light of the stringency of this statutory requirement for listing a source category, it would be unreasonable to interpret CAA section 111(b)(1)(B) to allow the Agency to regulate air pollutants from the source category merely by making an administrative determination under the open-ended and undefined rational basis test. Rather, it is logical to interpret CAA section 111(b)(1)(B) to require that the Agency apply the same degree of rigor in determining which air pollutants to regulate as it does in determining which source categories to list for regulation.

For these reasons, the EPA concludes that in the context of CAA section 111, the requirement that the EPA promulgate ''standards of performance,'' (CAA section 111(b)(1)(B)), defined as ''standard[s] for emissions of air pollutants'' (CAA section 111(a)(1)), must be interpreted to require a pollutant-specific SCF (CAA section 111(b)(1)(A)) as a predicate for promulgating standards of performance. At a minimum, the Agency considers this interpretation to be reasonable and, accordingly, adopts it. Requiring a pollutant-specific SCF establishes a clearer framework for assessing which air pollutants merit regulatory attention that will require sources to bear control costs. This promotes regulatory certainty for stakeholders and consistency in the EPA's identification of which air pollutants to regulate and reduces the risk that air pollutants that do not merit regulation will nevertheless become subject to regulation due to an unduly vague standard.

In the 2019 Proposal, the EPA solicited comment on whether to interpret CAA section 111(b)(1)(A) to require a determination that the pollutant causes or contributes significantly to dangerous air pollution (the SCF) or instead, to interpret it to require a determination that the pollutant simply causes or contributes to dangerous air pollution. 84 FR 50261. The same issue arises with respect to CAA sections 111(b)(1)(B) and (a)(1), but the EPA has concluded that interpreting these provisions to require a SCF as the pollutant-specific finding is consistent with the source-category SCF in CAA section 111(b)(1)(A). That is, in light of Congress' clearly expressed intent in CAA section 111(b)(1)(A) that the EPA base its listing of a source category on a finding that the emissions from the source category contribute significantly to dangerous air pollution, the EPA concludes that CAA sections 111(b)(1)(B) and (a)(1) require the EPA to base its regulation of a pollutant on a similarly rigorous finding that the pollutant contributes significantly to dangerous air pollution. If, in the alternative, the statute is ambiguous in this regard, the EPA exercises its

[46] As should be clear from this discussion immediately above, this interpretation of CAA sections 111(b)(1)(B) and (a)(1) differ from the interpretation of CAA section 111(b)(1)(A) that the EPA described in the 2019 Proposal. *See* 84 FR 50263 (stating that interpreting CAA section 111(b)(1)(B), the EPA was mindful that an Agency ''[may] avoid a literal interpretation at Chevron step one . . . [by] show[ing] either that, as a matter of historical fact, Congress did not mean what it appears to have said, or that, as a matter of logic and statutory structure, it almost surely could not have meant it'' (citation omitted)).

discretion to interpret it to require a pollutant-specific SCF.

In the 2019 Proposal, the EPA noted that interpreting CAA section 111 to require a pollutant-specific SCF as a predicate to regulation ''need not result in duplicative SCFs (or duplicative associated endangerment findings). That is, the EPA would not need to make separate SCFs (and associated endangerment findings) for both the source category and each pollutant emitted by the source category that the EPA seeks to regulate.'' 84 FR 50266. The EPA continues to hold this view. In identifying any new source categories under CAA section 111(b)(1)(A), the EPA could identify each air pollutant of concern and make a SCF, as appropriate, for emissions of each of those pollutants from the source category, and, in that same action, make the SCF for the source category itself. In addition, in the 2019 Proposal, the EPA solicited comment on what implications interpreting CAA section 111 to require a pollutant-specific SCF would give rise to for already promulgated standards of performance. *Id.* The EPA believes that standards of performance will generally not be affected by this requirement because generally, the EPA identified and analyzed the air pollutants of concern when the EPA listed a source category, or initiated promulgation of standards of performance at the same time or shortly after listing the source category, and, therefore, in association with the significance determination the Agency made in that listing. For example, as noted elsewhere, the EPA followed that process when it listed the Crude Oil and Natural Gas Production source category, that is, it identified and analyzed the air pollutants of concern at that time in the supporting documents. Importantly, the EPA relied on its analyses of those air pollutants as the basis for determining that the source categories' emissions contribute significantly to dangerous air pollution.[47]

B. Flaws in the 2016 Rule's Significant Contribution Finding

When the Administrator listed the oil and natural gas industry as a source category in 1979, he did not determine that methane emissions from the source category cause or contribute significantly to dangerous air pollution. In this rulemaking, the EPA is taking the position that the EPA must make that determination as a predicate to promulgating standards of performance for methane from this source category. The Administrator did determine in the 2016 Rule that methane from the source category contributes significantly to dangerous air pollution, but that determination was flawed and must be rescinded for two reasons: (1) The Administrator made that determination on the basis of methane emissions from the production, processing, and transmission and storage segments, instead of just the production and processing segments; and (2) the Administrator failed to support that determination with either established criteria or some type of reasonably explained and intelligible standard or threshold for determining when an air pollutant contributes significantly to dangerous air pollution.

1. Improper Scope of Source Category

In the 2016 Rule, the Administrator made the significant contribution finding on the basis of assessing methane emissions from the source category as defined to include the production, processing, and transmission and storage segments. In the present action, we are removing the transmission and storage segment, leaving only the production and processing segments. Because the 2016 Rule did not assess whether methane emissions from the production and processing segments alone cause or contribute significantly to dangerous air pollution, we find that the Rule's determination is not adequate and, therefore, we are rescinding it. Until the EPA makes an appropriate determination that methane emissions from the Oil and Natural Gas source category, properly calculated, contribute significantly to dangerous air pollution, it does not have authority to promulgate standards of performance for methane from these sources under CAA section 111(b)(1)(b).

2. Lack of Criteria or Standard for Determining Significant Contribution

In the 2019 Proposal, the EPA ''solicit[ed] comment on the question of whether the SCF in the 2016 . . . [R]ule can be considered appropriate given that nowhere in the course of developing and promulgating that rule did the EPA set forth the standard by which the 'significance' of the contribution of the methane emissions from the source category (as revised) was to be assessed.'' 84 FR 50267. The EPA elaborated that it was asking for comment on whether, as a matter of law, under CAA section 111, the EPA is obligated to identify the standard by which it determines whether a source category's emissions ''contribute significantly,'' and whether, if not so obligated, the EPA nevertheless fails to engage in reasoned decision-making by not identifying that standard. *Id.* The EPA cited *Motor Vehicle Mfrs. Assn. of United States, Inc.* v. *State Farm Mut. Automobile Ins. Co.,* 463 U.S. 29, 43 (1983), which states, ''Normally, an agency rule would be arbitrary and capricious if the agency has . . . entirely failed to consider an important aspect of the problem.''. *Id. See Department of Homeland Security* v. *Regents of Univ. of Cal.,* No. 18–587, slip op. at 18 (U.S. June 18, 2020) (executive action to rescind the Deferred Action for Childhood Arrivals program failed to provide a reasoned explanation when it failed to consider certain ''conspicuous issues''). For the reasons that follow, the EPA concludes that the failure to identify any such standard or any established set of criteria for the 2016 Rule's SCF for methane emissions from the source category is unreasonable and requires rescinding the 2016 Rule's SCF.

As the EPA noted in the 2019 Proposal, the ''contributes significantly'' provision in CAA section 111(b)(1)(A) is ambiguous. *See* 84 FR 50267–68 (citing *EPA* v. *EME Homer City Generation, L.P.,* 572 U.S. 489 (2014) (holding that a similar provision in CAA section 110(a)(2)(D)(i), often termed the ''good neighbor'' provision, is ambiguous)). Accordingly, the EPA has authority to interpret that provision. *Id.* at 50268. As noted above, the EPA reads CAA section 111(b)(1)(B) in light of CAA sections 111(b)(1)(A) and (a)(1) to incorporate the ''contributes significantly'' standard in connection with promulgating NSPS for particular air pollutants. The EPA has concluded that to allow the EPA to distinguish between a *contribution* and a *significant contribution* to dangerous pollution, some type of (reasonably explained and intelligible) standard and/or established set of criteria that can be consistently applied is necessary. Without at least one or the other, it is impossible to evaluate whether the SCF is well reasoned. Therefore, the lack of a standard or established set of criteria for the 2016 Rule's SCF renders the finding arbitrary and capricious. A supporting basis for this conclusion can be found in the EPA's analysis of the ''contribute significantly'' provisions of CAA section 189(e), concerning major stationary sources of PM with a diameter of 10 micrometers or less (PM_{10}). This provision requires that the

[47] The EPA also took the approach in the 2016 Rule that it is revising here, when it attempted to expand the Crude Oil and Natural Gas Production source category. It discussed the pollutant emissions, including GHG, VOC, and SO_2, made a SCF for those emissions, and, on the basis of that SCF, listed the expanded source category. 81 FR 35837 through 40.

control requirements applicable to major stationary sources of PM_{10} also apply to major stationary sources of PM_{10} precursors ''except where the Administrator determines that such sources [of precursors] do not contribute significantly to PM_{10} levels which exceed the standard in the area.'' As the EPA noted in the 2019 Proposal, in CAA section 189(e), Congress intended that, in order to be subject to regulation, the emissions must have a greater impact than a simple contribution not characterized as a significant contribution. However, Congress did not quantify how much greater. Therefore, the EPA developed criteria for identifying whether the impact of a particular precursor would ''contribute significantly'' to a NAAQS exceedance. 84 FR 50268. These criteria included numerical thresholds. *Id.*

The EPA has concluded similarly that, under CAA section 111(b), a standard or an established set of a criteria, or perhaps both, are necessary to identify what is significant and what is not. Moreover, without either, any determination of significance is arbitrary and capricious because it does not identify a reasoned basis for that determination.[48] This is evident in the flawed significance finding in the 2016 Rule. There, the EPA determined that ''the collective GHG emissions from the oil and natural gas source category are significant'' and based that determination on several facts concerning the amount of methane emissions from the Oil and Gas source category, in comparison to other domestic and global emissions. Specifically, the EPA stated that oil and gas GHG emissions are significant, whether the comparison is (i) ''domestic'' (noting that this sector is ''the largest source of methane emissions, accounting for 32 percent of United States methane and 3.4 percent of total United States emissions of all GHG''), (ii) ''global'' (noting that this sector, ''while accounting for 0.5 percent of all global GHG emissions, emits more than the total national emissions of over 150 countries, and combined emissions of over 50 countries''), or (iii) ''when both the domestic and global GHG emissions comparisons are viewed in combination.'' 81 FR 35840. The EPA did add a qualitative assessment of those facts. It noted that ''no single GHG source category dominates on the global scale,'' noted further that the oil and natural gas source category, ''like many (if not all) individual GHG source categories, could appear small in comparison to total emissions,'' and asserted that nevertheless, ''in fact, it is a very important contributor in terms of both absolute emissions, and in comparison to other source categories globally or within the United States.'' *Id.* However, the EPA did not identify any set of criteria by which to evaluate those facts and to ensure that those facts constituted the comprehensive set of data for determining significance. In contrast, when the EPA determines whether an area should be designated nonattainment on grounds that it ''contributes'' to ambient air quality problems in a nearby area, the EPA applies an established set of criteria that identify the relevant sets of data to analyze and explain how to analyze them. *See Catawba Cty.* v. *EPA,* 571 F.3d 20, 39–40 (DC Cir. 2009) (*Catawba*) (holding that in determining whether an area ''contributes'' to downwind ozone air quality problems, the EPA, ''[t]o be reasonable . . . must . . . define and explain the criteria the agency is applying''; explaining that the EPA adopted a set of nine criteria that it defined and explained ''in spades''). These criteria help ensure that the EPA's decision-making is well-reasoned and consistent. The EPA considers it particularly important to develop a set of criteria and/or a standard in order to determine when a *significant* contribution occurs, in order, as noted above, to distinguish it from a simple contribution. A contribution can be greater or lesser and remain a contribution, but a significant contribution determination necessarily involves a judgment about the degree of the contribution that rises to the level of significance. For such a judgment to be meaningful (and to be understood by regulated parties and by the public), the Agency must identify the criteria it will use to determine significance. In the 2016 Rule's significance finding, the EPA did not identify such criteria.

Nor did the EPA identify any threshold against which to compare the cited facts concerning methane emissions, and thereby assess their importance, much less explain why a contribution above such a threshold should be deemed significant while a contribution below it should not. Thus, for example, although the EPA justified the significance determination, in part, on grounds that the source category's emissions constitute 3.4 percent of total U.S. GHG emissions and 0.5 percent of all global GHG emissions, the EPA did not explain why either of those facts supports the significance determination. Because the EPA did not identify a threshold or criteria for evaluating the oil and gas industry's percentage of domestic or global GHG emissions, the EPA could not justify the 2016 Rule's SCF. As a result, that determination cannot be considered the result of reasoned and appropriate decision-making.[49] The EPA intends to begin

[48] As noted in the 2019 Proposal, in a 1994 rule concerning CAA section 213(a), which requires the EPA to make a finding that air pollutant emissions from new and existing nonroad engines and vehicles are ''significant contributors'' to dangerous air pollution, the EPA determined that it is not necessary to establish a ''specific numerical standard'' for determining significance. 84 FR 50268 (citing 59 FR 31306 and 31308 (June 17, 1994)). However, more recently, as further noted in the 2019 Proposal, the EPA promulgated criteria to interpret and apply ''contribute significantly'' in the ''good neighbor'' provision, CAA section 110(a)(2)(D)(i). 84 FR 50267 and 68 (discussing the criteria and the EPA's use of them in the Cross State Air Pollution Rule, which the U.S. Supreme Court upheld in *EPA* v. *EME Homer City Generation, LP.,* 572 U.S. 489 (2014)). In *Coalition for Responsible Regulation* v. *EPA (CRR),* the Court considered a challenge to the EPA's 2009 determination under CAA section 202(a) that GHG air pollution may reasonably be anticipated to endanger public health and welfare (the GHG Endangerment Finding) on grounds that the EPA had failed to quantify a threshold amount of GHG air pollution that would be safe and that, as a result, the EPA had no basis for concluding that the current amount may endanger. 684 F.3d 102, 122–23 (DC Cir. 2012), *aff'd in part and rev'd in part on other grounds sub nom. Utility Air Regulatory Group* v. *EPA,* 573 U.S. 302 (2014). The Court upheld the GHG Endangerment Finding, concluding that the EPA based it on an overall assessment of risk—accounting for ''the precautionary thrust of the CAA and the multivariate and sometimes uncertain nature of climate science''—for which no quantitative threshold is necessary. *Id.* at 123. That case is distinguishable because it focused on the endangerment finding for GHG air pollution, not on the amount of contribution that GHG emissions make to that air pollution. In any event, the contribution requirement of section 202(a)(1) requires only a simple contribution determination, not a significant contribution.

[49] In the EGU CO_2 NSPS Rule, the EPA determined, in the alternative, that CO_2 emissions from fossil fuel-fired EGUs contribute significantly to dangerous air pollution. The EPA explained that 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 EPA added that ''[t]he CO_2 emissions from even a single new coal-fired power plant may amount to millions of tons each year,'' and that ''the CO_2 emissions from even a single NGCC unit may amount to one million or more tons per year.'' The EPA also asserted that in that rulemaking, ''[i]t is not necessary'' 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.'' The EPA explained that ''under any reasonable threshold or definition, the emissions from combustion turbines and steam generators are a significant contribution.'' 80 FR 64531. In 2018, the EPA proposed to revise the EGU CO_2 NSPS Rule, and solicited comment on whether a SCF for GHG emissions from fossil fuel-fired EGUs was a necessary predicate for promulgating a NSPS for those emissions. ''Review of Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units—Proposed Rule, 83 FR 65424, 65432 n.25 (December 20, 2018). While the EPA has not taken final action

Continued

rulemaking shortly to identify thresholds and/or criteria and to apply them in future significance determinations.

Commenters objected that the 2016 Rule's SCF should not be considered invalid due to the lack of a standard by which to assess significant contribution, citing *Mississippi Commission on Envtl. Quality* v. *EPA,* 790 F.3d 138 (D.C. Cir. 2015) (*Mississippi*), the most recent decision in the line of cases that includes *Catawba,* noted above. In that line of cases, the Court upheld the EPA's approach to determining whether, under CAA section 107(d)(1)(A)(i), an upwind area should be treated as nonattainment because it ''contributes'' to downwind air quality problems. *See Mississippi,* 790 F.3d at 150 (citing *Catawba,* 571 F.3d at 39–40). The Court held that the EPA was not required to establish a threshold level of impact for determining whether an upwind area ''contributes'' to a downwind area. The *Mississippi* Court cited *Catawba,* 571 F.3d at 39–40), which commenters, in turn, cite to argue that such a threshold is not necessary for determining a significant contribution under CAA section 111(b). However, as noted above, the EPA had ''define[d] and explain[ed]'' a set of criteria for determining whether an upwind area ''contributes,'' and in the cited case law, the Court found that these criteria facilitated the reasonableness of the EPA's decision-making. *Catawba,* 571 F.3d at 39–40. In any event, this case law is distinguishable because it concerns the EPA's determination under CAA section 107(d)(1)(A)(i) of a simple contribution, whereas CAA section 111(b) requires the EPA to determine a *significant* contribution. As noted above, the EPA considers it particularly important to develop a set of criteria and/or a standard in order to determine when a significant contribution occurs, in order to distinguish it from a simple contribution.

C. Criteria for Making a Significant Contribution Finding Under CAA Section 111

In the 2019 Proposal, the EPA solicited comment regarding criteria for the Agency to consider in making a SCF. 84 FR 50267. The solicitation for comment was not on the factors the Agency should consider in determining whether air pollution may reasonably be anticipated to endanger public health or welfare, but rather the factors that should be considered when determining under CAA section 111 whether a pollutant from a source category significantly contributes to that air pollution. Several commenters recommend that the EPA defer any action on SCF criteria and suggest the EPA undertake these questions in a separate future rulemaking. Some commenters suggest specific criteria the EPA could consider.

The EPA made clear in the 2019 Proposal that it would not finalize criteria in this rulemaking, but rather would conduct a separate rulemaking to do so. 84 FR 50267. There is no need for the EPA to promulgate criteria at this time because this rule rescinds NSPS. The EPA expects that in the future, it will promulgate criteria before promulgating additional NSPS.

It should be noted that several commenters contend that oil and gas methane emissions are too small to be considered ''significant.'' For example, some commenters cite as support that the contribution of oil and gas methane to total U.S. GHG emissions is only about 3 percent, that U.S. methane emissions are only about 7 percent of global methane emissions, and that U.S. methane emissions are only about 1 percent of global GHG emissions. The EPA appreciates the commenters' views concerning the amounts and impacts of methane emissions from the transmission and storage segment, as well as the production and processing segments. The EPA acknowledges that depending on the criteria that it adopts to support a SCF in the future, such a relatively small contribution to the national and global pool of methane emissions may not be deemed significant. But until the EPA itself reviews and assesses those amounts of emissions according to the criteria that it eventually adopts, the EPA cannot make a determination as to whether methane emissions from the production and processing segments contribute significantly to dangerous air pollution.

VII. Implications for Regulation of Existing Sources

As discussed in section VII of the proposal preamble, the EPA recognizes that by rescinding the applicability of the NSPS, issued under CAA section 111(b), to methane emissions for the sources in the Crude Oil and Natural Gas Production source category that are currently covered by the NSPS, existing sources of the same type in the source category will not be subject to regulation under CAA section 111(d). This is a legal consequence that results from the application of the CAA section 111 requirements. Comments were received that both agreed and disagreed with the proposed decision and reflected varying opinions on the implications for regulation of existing sources. These comments are provided, along with the EPA's responses, in section X of this preamble and in Chapter 9 of the Response to Comments Document. None of the comments received resulted in a material change in the EPA's rationale and conclusions from proposal. The following provides a summary of the EPA's legal interpretation of CAA section 111(d)(1) and rationale for why the lack of regulation of existing sources under CAA section 111(d) will have a limited environmental impact.

A. Existing Source Regulation Under CAA Section 111(d)

As the EPA stated at proposal (see section VII of the 2019 Proposal preamble), CAA section 111(d) authorizes the regulation of existing sources in a source category for particular air pollutants to which a standard of performance would apply if those existing sources were new sources. By legal operation of the terms of CAA section 111(d), certain existing sources in the Crude Oil and Natural Gas Production source category will no longer be subject to regulation under CAA section 111(d) as a result of this final rule. Under CAA section 111(d)(1)(A), CAA section 111(d) applies only to air pollutants (1) for which air quality criteria have not been issued, and which are not on the EPA's list of air pollutants issued under CAA section 108(a) (commonly referred to as the ''CAA 108(a) exclusion''), and (2) which are not HAP emitted from a source category regulated under CAA section 112 (commonly referred to as the ''CAA 112 exclusion''). *See* 42 U.S.C. 7411(d)(1)(A) (CAA section 111(d) applies to ''any air pollutant (i) for which air quality criteria have not been issued or which is not included on a list published under section 7408(a) of this title or emitted from a source category which is regulated under section 7412 of this title'').

For reasons set out in the proposal preamble, the EPA has concluded that VOC fall within the CAA 108(a) exclusion and, thus, are not the type of air pollutant that, if subjected to a standard of performance for new sources, would trigger the application of CAA section 111(d). VOC are not expressly listed as CAA section 108(a) pollutants, but they are precursors to photochemical oxidants (*e.g.,* ozone) and PM, both of which are listed CAA section 108(a) pollutants. As provided in CAA section 302(g), the term ''air pollutant'' is defined to include

for that rule, the unique CO_2 emissions profile of fossil fuel-fired EGUs should be noted: The volume of emissions from EGUs dwarfs the amount of GHG emissions from every other source category.

precursors ''to the extent that the Administrator has identified such precursor or precursors for the particular purpose for which the term 'air pollutant' is used.'' For the following reasons, it is appropriate to consider VOC within the scope of photochemical oxidants and PM, which are listed CAA section 108(a) pollutants, for the particular purpose of applying the CAA section 108 exclusion in CAA section 111(d).

First, VOC are regulated through the CAA's NAAQS implementation program established under CAA section 110, as a result of the inclusion of ozone and PM on the CAA section 108(a) list, because VOC are precursors to those two listed pollutants. See, *e.g.,* CAA section 182(b)(2) (establishing ''reasonably available control technology'' requirements for VOC sources in moderate ozone attainment areas); CAA section 182(c)(2)(b) (requiring serious ozone areas to submit a reasonable further progress demonstration that will account for a set amount of VOC emissions reductions); CAA section 182(d)(2) (requiring specific VOC reductions to satisfy the offset requirement for severe areas); CAA section 182(e)(1) (requiring specific VOC reductions to satisfy the offset requirement for extreme areas). Indeed, the regulation of ozone precursors is the means of addressing ozone in the ambient air, because ozone levels in the ambient air are the result of photochemical reactions of precursors (VOC and NO_X), as opposed to being directly emitted from sources.

Second, as explained in the proposal preamble, excluding VOC from regulation under CAA section 111(d) makes sense within the CAA's three-part structure for addressing emissions from stationary sources. As the EPA has discussed in past rulemakings, the CAA 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 CAA sections 108 through 110); (2) hazardous pollutants (which are addressed under CAA section 112); and (3) ''pollutants that are (or may be) harmful to public health or welfare but are not or cannot be controlled under [CAA] sections 108–110 or 112.'' ''Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units: Final Rule,'' 80 FR 64661, 64711 (October 23, 2015) (quoting 40 FR 53340 (November 17, 1975)). Within this three-part structure, CAA section 111(d) is properly understood as a ''gap-filling'' measure to address pollutants that are not addressed under either the criteria pollutant and NAAQS implementation provisions in CAA sections 108 through 110 or the HAP provisions in CAA section 112. Because VOC are regulated as precursors to ozone and $PM_{2.5}$ under CAA sections 108 through 110, they are properly excluded from regulation under CAA section 111(d) because the ''gap-filling'' function of CAA section 111(d) is not needed.

Third, reading the phrase ''included on a list published under [CAA section 108(a)]'' as including precursors is reasonable in light of the provision in CAA section 112(b)(2) that restricts what pollutants may be listed as CAA section 112 HAP.

Finally, as discussed in detail in the proposal preamble, the fact that precursors are not always treated as CAA section 108(a) listed pollutants under all contexts across the CAA does not undermine the conclusion that they should be excluded under the CAA section 108 exclusion in CAA section 111(d).

B. Impact of Lack of Regulation of Existing Oil and Natural Gas Sources Under CAA Section 111(d)

The EPA maintains its position from the proposed rule that the lack of regulation of existing sources under CAA section 111(d) through an Emission Guideline (EG) will have limited impact. This is because there are several factors that will continue to contribute to the downward trend of total methane emissions from oil and natural gas existing sources even in the absence of an EG.

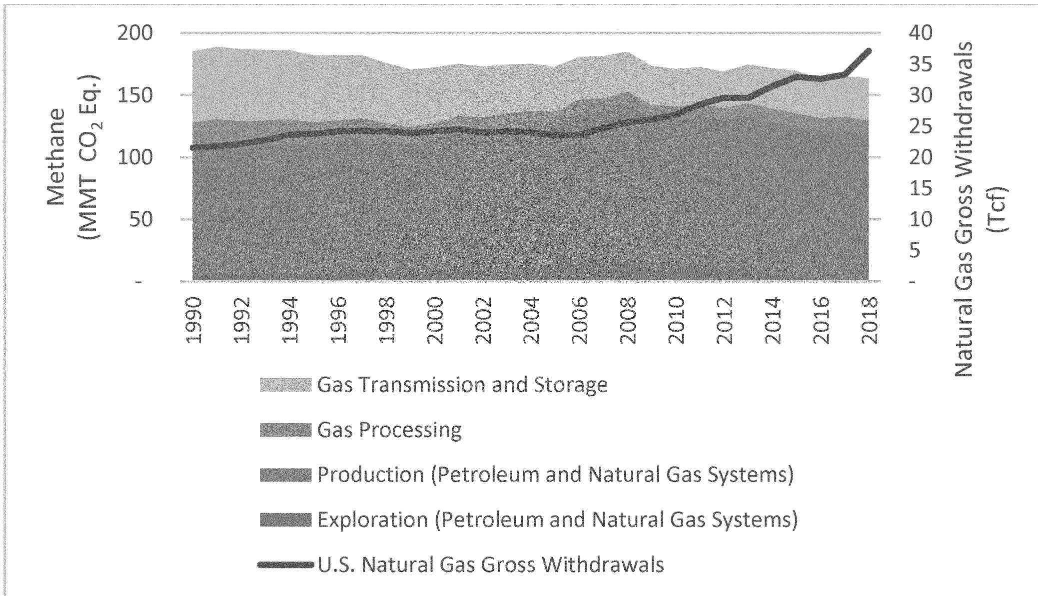
First, as the EPA stated in the 2019 Proposal preamble, the 2016 Rule includes a definition and approach to determining new source applicability that are very broad, and in the specific context of the oil and natural gas production industry, can be anticipated to result in wide applicability of the NSPS to existing sources due to the frequency with which such sources can be reasonably expected to engage in ''modification'' activity. Specifically, it would take at least 7 years from date of promulgation of an EG for requirements to be fully implemented.[50] During this time, the EPA expects that a percentage of existing sources will shut down or undertake modification which will result in them becoming subject to regulation under CAA section 111(b). However, based on limited information that commenters submitted, the EPA acknowledges there may be some existing sources that have never been modified and accepts that these are examples of existing sources that have continued to operate for long periods of time without being reconstructed or modified. The EPA did not prepare and include a quantitative analysis that estimates the levels at which source modification/equipment turnover may occur. However, the EPA maintains that this is one factor (among other factors) that in the absence of an EG will continue to contribute to the downward trend of total methane emissions from oil and natural gas existing sources.

Secondly, there are market incentives for the oil and natural gas industry to capture as much natural gas (and, by extension, methane) as is cost effective. Depending on the future trajectories of natural gas prices and the costs of natural gas capture and emission reductions, market incentives may continue to drive emission reductions, even in the absence of specific regulatory requirements applicable to methane emissions from existing sources. Assessing the relationship of methane emissions and natural gas production, overall natural gas gross withdrawals have increased about 50 percent from 1990 to 2018, while aggregate methane emissions from the NSPS subpart OOOOa-relevant industry segments have stayed relatively flat (Figure 1). This trend indicates decreasing aggregate methane emissions intensity for these segments over this period (Figure 1). These trends are likely driven by a combination of economic and technical advances.

[50] This estimation considers the development of states' plans and the Federal plan. Unlike NSPS, EG are not directly enforceable; thus, these mechanisms are critical for implementation.

[51] Methane emissions from Table 3–37 (Petroleum Systems) and Table 3–57 (Natural Gas Systems) in U.S. EPA. 2020. Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2018. EPA 430–R–20–002. Available at: *https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks-1990-2018.* Accessed July 1, 2020. U.S. Energy Information Administration (EIA) data on natural gas gross withdrawals available at: *https://www.eia.gov/dnav/ng/ng_prod_sum_a_EPG0_FGW_mmcf_a.htm.* Accessed July 1, 2020.

FIGURE 1. NET EMISSIONS OF METHANE EMISSIONS (FROM 2020 GHGI) and U.S. NATURAL GAS GROSS WITHDRAWALS IN TRILLION CUBIC FEET (TCF) (FROM U.S. ENERGY INFORMATION ADMISTRATION NATURAL GAS DATA), 1990 TO 2018.[51]



While environmental performance is a challenging concept to quantify in monetary terms, improving such performance is increasingly important for firms that seek to maintain a ''social license to operate.'' Generally speaking, the social license to operate means that the firm's employees, investors, customers, and the general public find that the firm's business activities and operations are acceptable to continue to freely participate in the marketplace. Maintaining the social license by improving environmental performance, such as reducing emissions, can help firms respond to the complex environment within which they operate in ways that are favorable to their longer-term business interests.

Third, the EPA maintains, and has received a substantial amount of comments confirming its position that participation in the various voluntary methane emissions mitigation programs is one factor (among other factors) that in the absence of an EG that will continue to contribute to the downward trend of total methane emissions from oil and natural gas existing sources. Owners and operators of facilities in the oil and natural gas industry participate in voluntary programs that reduce their methane emissions. Specifically, many owners and operators of facilities participate in two EPA partnership programs: The Natural Gas STAR Program [52] and the Methane Challenge Program.[53] Owners and operators also participate in voluntary programs that are not administered by the EPA, such as the Environmental Partnership [54] and the Climate and Clean Air Coalition (CCAC) Oil & Gas Methane Partnership.[55] Firms might participate in voluntary environmental programs for a variety of reasons, including attracting customers, employees, and investors who value more environmentally responsible goods and services; finding approaches to improve efficiency and reduce costs; and reducing pressures for potential new regulations or helping shape future regulations.[56] [57] The EPA does acknowledge that the industry as a whole is not uniformly meeting voluntary measures at the same level of control and that some companies may not be participating in cited voluntary methane emissions programs at all. This makes it difficult to verify the impacts on emissions as a result of voluntary program participation. Additional time will be needed to allow these programs to further develop and to be fully implemented to better quantify the impacts the varied programs have on

[52] The Natural Gas STAR Program started in 1993 and seeks to achieve methane emission reductions through cost-effective best practices and technologies. Partner companies document their voluntary emission reduction activities and report their accomplishments to the EPA annually. Natural Gas STAR includes over 100 partners across the natural gas value chain and has eliminated nearly 1.39 trillion cubic feet of methane emissions since 1993.

[53] The Methane Challenge Program, started in 2016 and designed for companies that want to adopt more ambitious actions for methane reductions, expands the Natural Gas STAR Program through specific, ambitious commitments; transparent reporting; and company-level recognition of commitments and progress. This program includes more than 50 companies from production, gathering and boosting, transmission and storage, and distribution.

[54] The Environmental Partnership is composed of various companies of different sizes and includes commitments to replace all high-bleed pneumatic controllers with low-bleed controllers (*i.e.,* controllers with a bleed rate less than 6 scfh) within 5 years, require operators to be on-site or nearby when conducting liquids unloading, and require initial monitoring for fugitive emissions at all sites within 5 years, with repairs completed within 60 days of fugitive emissions detection. *https://theenvironmentalpartnership.org/.*

[55] The CCAC Oil and Gas Methane Partnership is a technical partnership between oil and natural gas companies, the Environmental Defense Fund, the EPA Natural Gas STAR Program, and the Global Methane Initiative that provides technical documents on a wide variety of opportunities for reducing methane emissions and requires annual progress reports from its participants. Yearly data on the progress being made by participants is available on the CCAC website. *http://ccacoalition.org/en/content/oil-and-gas-methane-partnership-reporting.*

[56] Borck, J.C. and C. Coglianese (2009). ''Voluntary Environmental Programs: Assessing Their Effectiveness.'' Annual Review of Environment and Resources. 34(1): 305–324.

[57] Brouhle, K., C. Griffiths, and A. Wolverton (2009). ''Evaluating the role of EPA policy levers: An examination of a voluntary program and regulatory threat in the metal-finishing industry.'' Journal of Environmental Economics and Management. 57(2): 166–181.

reducing emissions from oil and natural gas industry sources.

Fourth, several major oil and natural gas producing states have established regulations on oil and natural gas sector emissions. The EPA recognizes that state requirements vary in stringency and that only a subset of states include requirements for sources that the EPA could potentially define as existing sources. However, states that have standards applicable to existing sources include California, Colorado, Utah, Wyoming (in the Upper Green River Basin ozone non-attainment area), and Texas, and account for a substantial portion of oil [58] and natural gas production [59] in the United States. Furthermore, current state regulations (and permits) controlling VOC emissions will concurrently reduce methane emissions from the oil and natural gas industry. For example, areas that are designated Moderate nonattainment and above for certain ozone NAAQS, and states within the Ozone Transport Region, are required to adopt and implement VOC controls for oil and gas sources covered by the EPA's 2016 Control Techniques Guidelines.[60] These controls, which the EPA will address through the state implementation plan (SIP) approval process, will concurrently reduce methane emissions.

As with other factors cited by the EPA, existing source state requirements are one factor (among others) that in absence of an EG will continue to contribute to the downward trend of total methane emissions from oil and natural gas existing sources. Further detail regarding comments received on the potential for limiting emissions from existing sources can be found in section X of this preamble.

VIII. Summary of Major Comments and Responses

In this section, we respond to many of the major comments made on the 2019 Proposal. In the Response to Comments Document in the docket, we provide additional discussion for some of these comments, and respond to additional comments.

A. Revision of the Source Category To Remove Transmission and Storage Segment

1. History of Scope of Oil and Natural Gas Source Category

Comment: Commenters assert that language in CAA section 111 demonstrates that Congress contemplated that source categories would be broad and encompass a variety of different types of emission sources. The commenters disagree that the 1979 listing did not include the natural gas transmission and storage segment, and add that, in 1980, the Agency explained: ''Source categories are intended to be broad enough in scope to include all processes associated with the particular industry.'' Commenters state that, in practice, the EPA has long listed broad source categories, covering an entire industry or a source that may be found in numerous industries, and sometimes establishing different subcategories within source categories, including electric utilities, non-metallic mineral processing, and compressor engines. The commenters contend that the EPA's treatment of other source categories soon after the priority listing process consistently recognized the interrelatedness of facilities or of emissions controls for those facilities and that this helps determine what sources to include in each source category. Although petroleum refineries are a separate source category under CAA section 111, the commenters note that the EPA previously explained that the source category for the asphalt roofing industry ''encompasses not only asphalt roofing plants but certain production units at oil refineries and asphalt processing plants which were not included on the Priority List promulgated on August 21, 1979.'' 45 FR 76405.

Response: The EPA has generally exercised discretion in identifying the scope of any particular industry, including which industrial processes it includes, for purposes of treating it as a source category under CAA section 111.[61] The EPA acknowledges that some of the listed source categories were broad in scope. However, the EPA has also listed source categories that are relatively narrow in scope—they have distinct facility boundaries that encompass a particular process that, in turn, follows a linear path and results in a specific product. Examples of narrowly defined source categories include the following.

- *Primary Copper Smelting, Subpart P:* A primary copper smelter is any installation or any intermediate process engaged in the production of copper from copper sulfide ore concentrates through the use of pyrometallurgical techniques. The affected facilities in primary copper smelters are dryers, roasters, smelting furnaces, and copper converters.
- *Nitric Acid Plants, Subpart G and Ga:* A nitric acid plant is a nitric acid production unit, which, in turn, is any facility producing weak nitric acid by either the pressure or atmospheric pressure process.
- *Kraft Pulp Mills, Subparts BB and BBa:* A kraft pulp mill is any stationary source which produces pulp from wood by cooking (digesting) wood chips in a water solution of sodium hydroxide and sodium sulfide (white liquor) at high temperature and pressure. Regeneration of the cooking chemicals through a recovery process is also considered part of the kraft pulp mill. The affected sources are digester systems, brown stock washer systems, evaporator systems, condensate stripper systems, recovery furnaces, smelt dissolving tanks, and lime kilns at kraft pulp mills.
- *Sulfuric Acid Plants, Subpart H:* The affected sources are sulfuric acid production units. These are defined as any facility producing sulfuric acid by the contact process by burning elemental sulfur, alkylation acid, hydrogen sulfide, organic sulfide and mercaptans, or acid sludge, but do not include facilities where conversion to sulfuric acid is utilized primarily as a means of preventing emissions to the atmosphere of sulfur dioxide or other sulfur compounds.

If the EPA does not originally include in a listing certain processes, and subsequently seeks to include those processes, the EPA must make the requisite statutory findings in order to do so. The action that the commenters cite supports this point. In the original 1979 Priority List, the EPA listed the Asphalt Roofing Plants source category. Subsequently, based on studies on the asphalt roofing industries, the EPA determined that the initial processing of asphalt for roofing manufacture may take place at sources other than asphalt roofing plants. Accordingly, the EPA, through rulemaking, amended the 1979 source category listing to include additional locations such as asphalt processing plants and asphalt storage tanks at oil refineries. *See* 45 FR 76427 and 28. In doing so, the EPA provided a specific rationale for broadening the source category. The present situation

[58] Approximately 52 percent of crude oil production in 2019 according to *https://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbblpd_a.htm.*

[59] Approximately 35 percent of natural gas production in 2019 according to *https://www.eia.gov/dnav/ng/ng_prod_sum_a_EPG0_VGM_mmcf_a.htm.*

[60] On October 27, 2016, the EPA provided notice of the availability of a final control techniques guideline document titled *Control Techniques Guidelines for the Oil and Natural Gas Industry* (EPA 453/B–16–001). 81 FR 74798 (October 27, 2016).

[61] The EPA has not relied on particular formulations, such as standard industrial classification, to identify an industry for purposes of classifying it.

requires a similar analytical framework: (1) The original source category listing for Crude Oil and Natural Gas Production was not broadly defined to include transmission and storage, and (2) the requisite statutory findings have not been made to expand the category to include it.

Comment: Several commenters assert that nothing in the 1979 listing decision supports the EPA's claim that the Agency at the time viewed facilities used in natural gas transmission and storage (*e.g.,* stationary pipeline compressor engines) as a separate source category.

Another commenter asserts that the omission in the 1979 listing of a source in the transmission and storage segment that had been included in the 1978 technical document suggests that this source was incorporated into the Crude Oil and Natural Gas Production source category. The commenter states that, while the EPA studied Stationary Pipeline Compressor Engines, which are found in the transmission and storage segment, as a potential independent source category in the 1978 technical document,[62] this source was not listed as a major or minor source in the 1979 Listing.[63] The commenter states that, while the Agency argues that the source was included in the Stationary Internal Combustion Engines listing, the EPA supports this proposition only by citing to a 2008 rule, which does not expressly include stationary pipeline compressor engines within the Stationary Internal Combustion Engines source category.[64] The commenter notes that the EPA cites to a page stating that ''[c]ategories and entities potentially regulated by this action'' include ''[a]ny manufacturer that produces or any industry using a stationary internal combustion engine as defined in the final rule.'' 73 FR 3568 and 69. The preamble contains a list of ''[e]xamples of regulated entities'' that includes ''[n]atural gas transmission.'' 73 FR 3569. However, according to the commenter, the applicability criteria of the final rule contains no explicit reference to stationary pipeline compressor engines.

Response: As a general matter, the Agency has the authority to revisit its prior categorization determinations. Nonetheless, the EPA, upon a close read of its prior rules believes that this and certain other comments on prior Agency determinations are mistaken, as described further in this section. The EPA notes that while it believes the 1979 listing did not include the transmission and storage segment for the reasons described in this final rule, any interpretation otherwise (*i.e.,* that the listing did include this segment) did not have any practical effect until the 2012 Rule, when the EPA promulgated standards for this segment for the first time. Therefore, to the extent the 1979 listing can be considered to have included the transmission and storage segment, the EPA is alternatively determining that such inclusion was incorrect for the same reasons why the 2012 and 2016 Rules incorrectly included the segment as part of the source category.

The EPA disagrees with the commenter's suggestion that the 1979 listing incorporated stationary pipeline compressor engines into the Crude Oil and Natural Gas Production source category. This is clearly evidenced by examining the pollutants which are identified for the category. For the 1979 listing, the pollutants identified for the Crude Oil and Natural Gas Production source category were VOC and SO_2. In the 1978 background documentation, the pollutants identified for stationary pipeline compressor engines were NO_X, SO_2, and carbon monoxide (CO). If the EPA had included stationary pipeline compressor engines in the Crude Oil and Natural Gas Production source category in 1979, the Agency likely would have added NO_X and CO to the list of pollutants for the category.

That the Stationary Internal Combustion Engine rule (40 CFR part 60, subpart IIII) covers engines in the natural gas transmission and storage segment is further evidenced by the statement from the February 26, 2008, **Federal Register** document that specifically identifies engines in natural gas transmission as example entities subject to the rule. The commenter is incorrect in asserting that the applicability criteria of the regulations are silent on engines in natural gas transmission. Those applicability criteria are *characteristics* of the engine (*e.g.,* maximum engine power), which are unrelated to the *location* of the engine (*e.g.,* in the transmission segment). *See* § 60.4230 of 40 CFR part 60, subpart JJJJ. Therefore, the lack of explicit mention of the transmission segment does not mean that engines in that segment are not included in the category.

Comment: Several commenters stated that the description of the Crude Oil and Natural Gas Production source category in the 1984 proposed NSPS for VOC and SO_2 emissions made clear that the category did not include transmission and storage operations. The commenters pointed to the statement in the preamble that the source category excluded emission sources related to the ''distribution'' of products ''to petroleum refineries and gas pipelines'' (citing, *e.g.,* 49 FR 2636.

Other commenters disagree. One commenter asserts that the EPA defined the source category as ''encompass[ing] the operations of exploring for oil and natural gas products, drilling for these products, removing them from beneath the earth's surface, and processing these products from oil and gas fields for distribution to petroleum refineries and gas pipelines.'' The commenter states that it is clear that compressor stations within the transmission and storage segment ''process these products . . . for distribution'' by compressing the gas and forcing it through the pipelines.

Response: The EPA does not agree with the commenter's interpretation of the quotation from the 1984 proposal. Specifically, the EPA does not agree that the compression of the natural gas along transmission pipelines constitutes processing of the natural gas. Natural gas processing has historically been defined by the Agency to include the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both. (40 CFR part 60, subpart KKK; 40 CFR part 63, subpart HH). The EPA maintains that the language in the 1984 proposal, *i.e.,* that the category includes ''the operations of exploring for oil and natural gas products, drilling for these products, removing them from beneath the earth's surface, and processing these products from oil and gas fields for distribution to petroleum refineries and gas pipelines,'' is not ambiguous. Following the well-defined ''processing'' operations, the natural gas enters transmission gas pipelines. These are the gas pipelines referred to in the 1984 preamble, meaning that the gas leaves the processing segment of the oil and natural gas production source category and travels to the next segment, the natural gas transmission pipelines.

Comment: One commenter asserts that, within the 1984 definition of the production segment, the EPA drew a definitional boundary whereby production consisted of extraction ''and processing [of oil and natural gas] for distribution to petroleum refineries and gas pipelines.'' The commenter states that this implies that the boundary at which the Agency has always historically defined the category as being where production meets local distribution to pipelines or refineries. The commenter states that this interpretation of the CAA meant that the

[62] U.S. EPA. Priorities for New Source Performance Standards Under the Clean Air Act Amendments of 1977. April 1978. EPA–450/3–78–019. p. 33.

[63] 44 FR 49222 through 49226.

[64] 73 FR 3568, 3569 (January 18, 2008).

production segment abuts the distribution end of the industry—not an arbitrarily created ''Transmission and Storage'' segment.

Response: The EPA's use of the term ''distribution'' in the 1984 preamble was misinterpreted by the commenter. The commenter appears to interpret ''distribution'' as the distribution segment of the natural gas industry, and that the source category includes everything up to that segment. In the context of the 1984 preamble, the EPA's use of the term ''distribute'' means the transfer to the next segment of the industry.

Comment: A commenter asserts that the 1984 proposal serves to demonstrate that the EPA did not view its listing as constrained to its literal terms—''Crude Oil and Natural Gas Production''—because the 1985 NSPS regulated the processing, not the production, segment of the natural gas industry. Specifically, the EPA stated that, with regard to the discussion of equipment leaks, ''equipment used in crude oil and natural gas production (not to be confused with natural gas processing) for equipment leaks of VOC is not appropriate for widely dispersed equipment.'' 49 FR 2637. The commenter states that, taken to a literal extreme, the proposal's argument would mean that the 1985 NSPS exceeded the scope of the source category and was, thus, unlawful.

Response: The EPA agrees that the language that the commenter quotes indicates the Agency's view in the 1985 NSPS that the source category covered both production and processing. However, this does not in turn mean that the Agency thought that the source category included the transmission and storage segment as well. As described above, the 1984 proposal acknowledged equipment leaks in the production segment but declined to set standards for them based on a technical analysis. This discussion makes clear that the Agency considered production to be part of the source category. In contrast, as discussed above, the preamble is silent on equipment leaks in the transmission and storage segment.

Comment: Further, the commenter states that the EPA's proposal appears to concede that the Agency has never been limited to regulating only those specific sources within the listed category that it regulated in the first NSPS. The commenter states that, prior to 2012, the EPA had issued standards for emissions at gas processing plants only as part of the ''Crude Oil and Natural Gas Production.'' The commenter notes that in 2012 the EPA regulated VOC from previously unregulated upstream sources, including well completions, centrifugal compressors, reciprocating compressors, pneumatic controllers and storage vessels (citing 77 FR 49490 (Final Rule promulgating 40 CFR part 60, subpart OOOO)). The commenter states that these sources were not part of the EPA's analysis in 1979 or 1984 NSPS, yet the proposal does not suggest that they were improperly regulated in the 2012 Rule. Specifically, in 2012 the EPA stated: ''[i]n addition to the operations covered by the existing standards, the newly established standards will regulate volatile organic compounds from gas wells, centrifugal compressors, reciprocating compressors, pneumatic controllers and storage vessels'' (citing 77 FR 49490).

The commenter also indicates that the EPA's citation to the 1984 NSPS ignores other statements made during other rulemakings for the source category, including the same 1984 rulemaking, that suggest that the source category was intended to cover broadly the oil and natural gas sector, or at least was not limited to production and processing (citing 84 FR 50256). The commenter states that, in that NSPS, the EPA felt the need to exclude specifically certain sources found in the transmission and storage segment from the standards it set, something that would not have been necessary if the Agency had intended to exclude these segments themselves from the definition of the source category. The sources excluded in that NSPS are compressor stations, dehydration units, sweetening units, underground storage facilities, and field gas gathering systems, unless the facility is located at an onshore natural gas processing plant.

Response: The commenter's representation of the 1984 rulemaking is not entirely accurate. It is true that the 1984 proposal limits the sources covered to those at natural gas processing facilities. However, the EPA does not agree that this rulemaking was an expansion of the original ''Crude Oil and Natural Gas Production'' source category. The commenter is implying that natural gas processing operations were not included in the original source category listing in 1979 but does not provide any evidence from the 1978/1979 actions to support that assertion. An alternative interpretation of this text could also be that the Agency wished to make it sufficiently clear that while sources in part of the production and processing segment are included in the source category, the same sources that are part of the transmission and storage segment are not included in the source category. However, in the absence of an explanation for this exclusion, the most that can be taken away from this text is that these sources are not subject to the 1984 NSPS; this text alone is not dispositive on whether these sources are included in the broader Oil and Natural Gas source category. Therefore, the commenter extrapolates a conclusion without a basis to do so. The fact that SO_2 was a pollutant identified for the Crude Oil and Natural Gas Production source category clearly shows that processing was included, as the sweetening units covered by the 1984 proposed rules are the primary source of SO_2 emissions in the oil and natural gas industry.

In addition, there are numerous statements made by the EPA throughout the 1984 proposal that clearly demonstrate consideration of sources across the entire Crude Oil and Natural Gas Production source category. The commenter cites the statement in the1984 proposal that emission points can be divided into three categories and uses this statement to argue that the source category included transmission and storage. However, the comment fails to include the remainder of the paragraph that includes that statement:

> These emission points can be divided into three main categories: Process, storage, and equipment leaks. Process emission sources include well systems, field oil and gas separators, wash tanks, steeling tanks, and other sources. *These process sources remove the crude oil and natural gas from beneath the earth and separate gas and water from the crude oil. Best demonstrated control technology has not been identified for these process emission points; therefore, these sources have not been considered in developing the proposed standards.* 49 FR 2637 (emphasis added).

This part of the paragraph clarifies two points. First, the EPA clearly considered the upstream sources (well systems, field oil and natural gas separators, etc.) as part of the source category but indicated that since best demonstrated control technology had not been identified for those sources, no standards were being proposed at that time. These sources were then addressed in the 2012 rulemaking, when the best demonstrated technology/BSER had been determined for them. Second, this discussion did not mention operations in the transmission segment.

One commenter also refers to the parenthetical in the 1984 proposal related to oil and natural gas production and argues that it is proof that natural gas processing was not included in the Crude Oil and Natural Gas Production source category. The following provides more of the discussion to provide the full context.

> Equipment leaks of VOC can occur from pumps, valves, compressors, opened ended

lines or valves, and pressure relief devices used in onshore crude oil and natural gas production. These leaks usually occur due to design or failure of the equipment. Equipment used in crude oil and natural gas production (not to be confused with natural gas processing) are widely dispersed over large areas. The analysis presented in the BID for the principal control technique (leak detection and repair work practices) for equipment leaks of VOC is not appropriate for widely dispersed equipment. The costs and emission reduction numbers for such an analysis are unknown at this time. Thus, the proposed standards do not apply to equipment associated with crude oil and natural gas production. The proposed standards apply only to equipment located at onshore natural gas processing plants. 49 FR 2637.

Taking the 1984 preamble excerpt in context illustrates that the distinction made between production and processing was specifically related to the application of leak detection and repair work practices for equipment leaks and not to define the source category. In fact, the discussion makes it clear that the EPA's definition of the source category includes production and processing. Again, there is no mention here of the application of leak detection and repair programs to the transmission and storage segment.

Finally, the commenter cites a paragraph from the proposed regulation, which clarifies that sources not located at a natural gas processing plant are not affected facilities, as evidence that the category includes the transmission and storage segment, since ''compressor stations'' are included. This is also not a compelling argument. It is not uncommon for equipment, other than that used to extract natural gas liquids from field gas or to fractionate mixed natural gas liquids to natural gas products, to be located at a natural gas processing plant. This paragraph—40 CFR 60.630(e)—simply clarifies that if other operations (*i.e.,* compressor stations, dehydration units, sweetening units, underground storage facilities, field gas gathering units, and liquefied natural gas units) are located at a natural gas processing plant, the associated components are subject to the leak detection and repair requirements in NSPS subpart KKK. This list cannot be extrapolated to the conclusion that the EPA considered all these operations to be in the source category. As evidence of this note that ''liquefied natural gas units'' are included in the list. These units, while part of the overall oil and natural gas industry, have never been contemplated as being part of the Crude Oil and Natural Gas source category.

2. ''Sufficiently Related'' Test and Whether Transmission and Storage Operations Are Distinct From Production and Processing

Comment: Commenters contend that the proposal to amend the source category definition is fundamentally at cross-purposes with the proposal to remove standards of performance for methane. The EPA proposed to justify the latter by finding that regulation of methane and VOC is redundant because the controls that sources are required to implement to reduce their VOC emissions will also reduce their methane emissions, and this is true regardless of the relative amounts of VOC and methane in their overall emissions. The commenters state that if methane regulation is redundant on those grounds, then differences in gas composition cannot be the basis for determining that two distinct source categories are necessary.

Response: The commenters conflate the proposal to remove the transmission and storage segment from the source category with the proposal to rescind the methane requirements for the remaining production and processing segment, without acknowledging that while the substance of each may have technical similarities, each proposal addresses discrete, stepwise legal aspects of CAA section 111(b). Under CAA section 111(b), a source category must first be listed before the EPA can promulgate an NSPS for sources within the category. The EPA proposed the first action of removing the transmission and storage segment from the source category, in part based on the conclusion that the segment was not previously properly added to the source category because there are distinct differences in operations and differences in the emissions profiles between the production and processing segments and the transmission and storage segment. As described further in this section, based on the sufficiently related test, these distinct differences in operations and differences in emissions profile means that the transmission and storage segment requires a separate SCF in order to be properly regulated under CAA section 111(b).

However, once a source category is properly listed and defined, as are the production and processing segments, the inquiry then is what are the appropriate standards of performance for sources within that category. This inquiry is separate from and subsequent to the initial inquiry of whether a source category is properly identified for regulation under CAA section 111(b). For example, the EPA has previously identified sources as appropriately subject to regulation under CAA section 111(b), but then subsequently declined to promulgate standards of performance based on inadequate data. In proposing VOC standards for equipment leaks in oil and gas processing, the EPA declined to apply such standards to equipment in the production segment, which is clearly part of the source category, because it did not have data on costs and emission reduction numbers at that time. 49 FR 2637.

Similarly, here, while the production and processing segments have been properly identified as subject to regulation under CAA section 111(b) through the 1979 listing of the source category, the EPA must then contend with *how* to regulate these segments. Accordingly, the EPA proposed the second action to rescind the methane requirements for the production and processing segments based on the fact that VOC and methane controls are redundant. While the rationales for both actions are premised partly on differences in gas composition, the legal and technical inquiry for each action is different, as these are discrete steps to regulation under CAA section 111(b). Though the findings under each inquiry are similarly premised on differences in gas composition, that does not mean that the response to both inquiries must be the same, as each inquiry is distinctly different from one another (*i.e.,* one is whether the transmission and storage segment is properly part of the source category, the other is whether and how to regulate methane from the production and processing segments). The rationale for this second action was also discussed at length in section IV.D of the 2019 Proposal (84 FR 50259 and 50260). The comments received and the EPA responses on this second action are provided in section VIII.B below.

Comment: Commenters do not agree that the transmission and storage segment cannot be included in the Crude Oil and Natural Gas source category because the gas composition and operations in that segment are too different from those in the production and processing segments. These commenters assert that the EPA's own data do not support the EPA's rationale. The commenters suggest that, while the EPA compares the average composition of the production segment to the average composition of the transmission segment, the Agency fails to consider the extensive overlap in the range of compositions in both segments. The commenters state that the EPA's 2011 Natural Gas Composition memorandum data show the wide range of compositions of gas in the production and transmission segments.[65] The commenters contend that the range of methane compositions in the production segment fully encompasses the range in the transmission segment, demonstrating the similarity of the gas composition in the two segments; similarly, there is extensive overlap between the segments' VOC compositions.

Commenters also discussed the EPA's more recent 2018 composition data,[66] asserting that it shows even more variation in gas composition. A commenter asserts that while the EPA recognizes that variations in the gas composition can occur from basin-to-basin within each segment, the EPA does not acknowledge that these basin-to-basin variations can swamp the purported variations on which the EPA relies to justify a distinction between production and transmission segments.

One commenter states that its experience with the oil and natural gas industry operating in Pennsylvania shows that unprocessed field gas [67] can range from, by volume, 75-percent to 98-percent methane and 0.1-percent to 10-percent VOC. The commenter states that in a number of Pennsylvania counties, the county average field gas composition meets the EPA's pipeline quality gas composition (*i.e.,* is equal to or greater than 93-percent methane and less than or equal to 1-percent VOC; HAP data is unavailable). The commenter states that there are several natural gas well pads that dehydrate the produced gas onsite and transfer custody directly to an interstate pipeline. The commenter notes that this reality further blurs the distinction between the production and the transmission and storage segments. The commenter contends that, if a well site is required to meet the requirements of the 2016 Rule, it stands to reason that a transmission compressor station accepting the same gas should be required to meet the same requirements.

One of the commenters also notes that the 2018 Natural Gas Composition memorandum did not include any updated data for the transmission and storage segment. The commenter states that, given the significant difference in the production segment data from 2011 and 2018, the EPA must collect more current data for the transmission and storage segment if it seeks to justify any claims about the segment being sufficiently distinct from production and processing to warrant revision of the source category.

Response: The EPA recognizes that the composition of natural gas in the production segment can vary considerably, and that in some basins/areas it is possible that the composition can mirror that in the transmission segment. However, while the commenters stress this overlap in the gas composition in limited geographical regions in the U.S., such as in some parts of Pennsylvania, they seem to discount the substantial differences in most areas. For example, for Texas, the EPA's 2011 gas composition analysis showed that the methane content in the production segment was, on average, 80.1 percent, but ranged from 55.0 percent to 97.8 percent.[68] Because the NSPS subpart OOOOa is a nationwide regulation which applies equally across the country, it is most appropriate to consider the average composition for the segments. Further, on a nationwide basis, the data clearly reveal a distinction in the gas composition between the production and processing segments and the transmission and storage segment.

The commenter is correct that the 2018 Natural Gas Composition memorandum did not include data for the transmission and storage segment. The EPA conducted a new analysis which analyzed average methane concentrations using 2015 through 2018 data reported under 40 CFR part 98, subpart W (Petroleum and Natural Gas Systems), of the EPA's GHGRP.[69] This analysis did include recent data for the transmission and storage segment. The EPA found that there is a statistically significant difference between the average methane concentration in natural gas at either the gas production, gathering and boosting, or gas processing [70] industry segments and the average methane concentration in natural gas at either the transmission compression or underground storage segment. This difference further supports the EPA's justification to remove the transmission and storage segment from this source category.

Comment: Several commenters disagree with the EPA's statements in the 2019 Proposal that equipment and operations in the production and processing segments were not interrelated with the transmission and storage facilities. The commenters contend that while the transmission and storage segment serves a different role than the production, processing, and distribution segments, it is still part of the overall oil and natural gas industry and is a necessary element of the source category because it prepares the recovered gas for distribution. They add that, as the 2019 Proposal notes, the processes used to remove impurities (for example, dehydrators) in the production and processing segments are also used in the transmission and storage segment (citing 84 FR 50258). Commenters noted that the 2016 Rule stated that the equipment and operations at production, processing, transmission, and storage facilities are a sequence of functions that are interrelated and necessary for getting the product ready for distribution (citing 81 FR 35838). Commenters also noted that the 2016 Rule also cited the increase in natural gas production from hydraulic fracturing and horizontal drilling as an example of the interrelated nature of the industry—*i.e.,* increased production resulting in an increase in the amount of natural gas needing to be processed and moved to market or stored, which in turn results in increases in emissions across the entire natural gas industry.

Response: The EPA agrees with the commenters that production, processing, transmission and storage are all segments of the oil and natural gas industry and that the transmission and storage segment is a part of the industry because it prepares the recovered gas for distribution.

However, this does not necessitate that all of the segments belong in the same source category for regulatory purposes under CAA section 111. As explained in the 2019 Proposal, the primary purposes of each segment differs. The purposes of the production and processing segments are to explore, drill, extract, and process crude oil and natural gas found beneath the earth's surface. Extracting crude oil and field gas through drilling wells and processing these products for distribution to petroleum refineries and gas pipelines is an industrial process that is distinct from the transmission and storage segment, whose primary purpose is to move to market pipeline quality natural gas through transmission

[65] Memorandum to Bruce Moore, U.S. EPA from Heather Brown, EC/R. ''Composition of Natural Gas for use in the Oil and Natural Gas Sector Rulemaking.'' July 2011. Docket ID Item No. EPA–HQ–OAR–2010–0505–0084.

[66] Memorandum to U.S. EPA from Eastern Research Group. ''Natural Gas Composition.'' November 13, 2018. Docket ID No. EPA–HQ–OAR–2017–0757.

[67] Field gas is described earlier in section V.B of this preamble.

[68] Memorandum to Bruce Moore, U.S. EPA from Heather Brown, EC/R. ''Composition of Natural Gas for use in the Oil and Natural Gas Sector Rulemaking.'' July 2011. Docket ID Item No. EPA–HQ–OAR–2010–0505–0084.

[69] Analysis of Average Methane Concentrations in the Petroleum and Natural Gas Industry Using Data Reported Under 40 CFR part 98 Subpart W. April 6, 2020. Included in Docket ID No. EPA–HQ–OAR–2017–0757.

[70] Methane concentrations at gas processing facilities evaluated in this study are based on the inlet gas composition (as received) by the gas processing facilities.

pipelines by increasing the pressure and to store the gas underground along the pipeline.

The EPA understands that dehydrators are used to remove impurities from the natural gas in both the production and processing segments and in the transmission and storage segment. In the latter segment, dehydrators are occasionally present along transmission pipelines and at natural gas storage facilities to remove water and other impurities that condense as a result of temperature and pressure changes as the gas moves through the pipeline or is stored underground. However, the different uses of dehydrators illustrate the separate functions that the segments have in the industry. In the transmission and storage segment, dehydrators simply remove these impurities as they accumulate in pipelines. In the production and processing segment, dehydrators are a part of the process to change the overall composition of the gas. It is also noteworthy that the EPA included and regulated air toxics emissions from dehydrators in two separate source categories and in two different NESHAP. Dehydrators in the production and processing segments are covered by 40 CFR part 63, subpart HH, and dehydrators in the natural gas transmission and storage segment are covered by 40 CFR part 63, subpart HHH.

The EPA continues to assert that the comparison with the petroleum industry is directly relevant. The commenters insist that the necessary link between the extraction and processing of the natural gas in the production and processing segments and the transmission of the natural gas predetermines that the two segments must be treated as a single source category. However, this same link exists between the extraction and processing of oil, condensate (and other liquids from oil and natural gas wells) in the production segment and the petroleum refineries and pipelines that refine/process and distribute these liquids. However, the commenters do not suggest the interrelatedness of the production and processing sources originally included in the Crude Oil and Natural Gas Production source category with those in the petroleum liquid source categories necessitates that Crude Oil and Natural Gas Production and Petroleum Refineries be combined into one category and regulated together. The EPA applies the same logic to conclude that the fact that the transmission and storage segment is related to the production and processing sources in the Crude Oil and Natural Gas Production source category does not necessarily result in the requirement that they be regulated together. In addition, other instances in which similar source types emitting the same air pollutants and subject to the same types of controls are included in different source categories. For example, leaking pumps, valves, connectors, and other components at a wide variety of types of facilities that emit VOC and GHG are included in different source categories.

3. The Authority To Expand Source Categories and the EPA's Alternative Approach

Comment: One commenter asserts that, while the 2012 Rule and 2016 Rule expanded the source category, this expansion was appropriate considering the statutory mandate that the Administrator should from time to time review the source categories. The commenter states that the purpose of this review was to assure that the EPA periodically consider new scientific developments to ensure that the Agency was continually acting in a way that protected the public health. The commenter adds that the statute provides no guidance regarding the proper scope of a source category, and that Congress left that determination to Agency expertise, so long as the Agency considers the impacts of the source's emissions on public health. According to the commenter, the EPA's expansion of the source category in the 2016 Rule properly considered the source category's impact on the public health. However, the commenter adds, but the EPA's current effort to rescind that expansion is based on alleged procedural errors and fails to consider the public health impacts of the transmission and storage segment. The commenter states that the transmission and storage segment does significantly contribute to the deterioration of public health. The commenter asserts that the natural gas held at storage facilities contains all of the same toxic air pollutants and hazardous chemicals as natural gas does at other stages of the production process, and that the methane and VOC emissions from compressor stations have the same adverse impact on public health regardless of what segment of the source category the methane and VOC emissions are coming from. The commenter suggests that the EPA take this opportunity to do its own analysis to determine whether methane, VOC, and HAP (air toxic) emissions from the transmission and storage segment of the source category adversely impact public health.

Response: The EPA agrees that the CAA authorizes the EPA to review and revise source categories, and that its purpose was to ensure that the Agency was continually acting in a way that protected the public health. However, the EPA disagrees with the commenters' position on the EPA's past consideration of public health in the expansion of the Crude Oil and Natural Gas source category. The EPA's 2015 evaluation of the impacts of GHG, VOC, and SO_2 on public health and welfare (80 FR 56601) was conducted for crude oil and natural gas production and processing, along with natural gas transmission and storage. While it is true, as the commenter points out, that methane and VOC are emitted from the natural gas transmission and storage segment, the EPA's 2015 analysis did not separate the impacts of the pollutants emitted by natural gas transmission and storage to demonstrate that the emissions from this segment contribute significantly to the overall impacts. In the 2019 Proposal, the EPA proposed that it was required to make a finding that the transmission and storage segment, in and of itself, contributes significantly to air pollution which may reasonably be anticipated to endanger public health and welfare. Nothing in the comments provided cause the EPA to change this conclusion.

4. Significant Contribution Finding for Natural Gas Transmission and Storage

Comment: Several commenters state that the SCF that the EPA made in the 2016 Rule, which was for the production, processing, transportation, and storage segments collectively, was not appropriate to authorize the EPA to promulgate NSPS for sources in the transmission and storage segment. The commenters assert that to regulate sources in that segment, the EPA was required to make a SCF determination for emissions from that segment itself. Commenters explain that, to consider otherwise, once the EPA makes a SCF determination for a source category consisting of certain types of sources, the Agency would then be able to add into that source category all manner of ancillary equipment and operations, even if those ancillary equipment and operations do not in and of themselves significantly contribute to the previously-identified endangerment. The commenter states that this would allow the EPA to evade the express listing criteria by lumping loose associations of nominally related segments of an industry into a sector.

Other commenters disagreed, stating that in the 2016 Rule, the EPA determined that the rulemaking record supported a revision of the source category listing to include broadly the entire oil and natural gas industry (*i.e.,* production, processing, transmission and storage) that, in the Administrator's judgment, contributes significantly to air pollution which may reasonably be anticipated to endanger public health or welfare. Commenters add that CAA section 111(b)(1)(A) grants the Administrator authority to ''from time to time . . . revise'' the listed categories, and that nothing in the statutory text or relevant case law suggests that the EPA must, before revising a source category in a way that expands its scope, make a SCF determination for the newly added part of the category, considered alone. The commenter adds that nothing in the statute indicates that Congress intended for it to be more difficult for the EPA to add sources to a category than to include those sources in the category in the first instance. The commenter states that the EPA's obligation when revising a source category is only to conclude that the entire category, as revised, can still be deemed to contribute significantly to pollution that endangers public health or welfare.

Response: In this action, the EPA is determining that the transmission and storage segment of the oil and natural gas industry should not be included with the production and processing segments as a single source category. For that reason, if, in the future, the EPA seeks to promulgate standards of performance for any air pollutants from the transmission and storage segment, it must first list the segment as a source category and then determine that their emissions cause or contribute significantly to air pollution reasonably anticipated to endanger public health or welfare (SCF). Commenters take different positions on the question of whether the EPA must make a SCF for the transmission and storage segment as a predicate to adding them into a source category that already includes the production and processing segments. However, because the EPA is determining that the transmission and storage segment was not properly added to the source category, it is not necessary to resolve that question, and the EPA does not do so in this action.

Comment: Several commenters assert that, in order to remove transmission and storage segment sources from the Oil and Natural Gas source category, the EPA must affirmatively show that emissions from the sources do not significantly impact public health.

Response: The EPA disagrees with this comment. In this action, the EPA is determining that its previous determinations that the Crude Oil and Natural Gas source category included the transmission and storage segment beginning in 1979, or, in the alternative, that the EPA was justified in expanding the category to include that segment, were improper. Rather, the EPA is determining that the source category did not include that segment beginning in 1979 and that the EPA's action in 2012 and 2016 to add this segment into the source category was improper. These reasons justify the EPA in determining that the proper scope of the source category is the production and processing segments alone. There is no requirement under CAA section 111 that the improperly added segment must remain in the source category until the EPA determines that they do not cause or contribute significantly to dangerous air pollution.

5. Whether EPA Must Move To Add/Expand the Source Category and Regulate Transmission and Storage Emission Sources

Comment: Several commenters suggest that if the EPA finalizes the proposal to remove natural gas transmission and storage and rescind the applicable requirements for this segment, that the EPA should also move to properly and legally expand the source category and regulate natural gas transmission and storage emission sources. The commenters state that, beyond asserting that it might do so in the future, the proposal fails to explain why it does not take the logical next step and assess whether the emissions from the transmission and storage segment contribute significantly to dangerous pollution. The commenters contend that the current record, as well as the EPA's past findings, demonstrates that the emissions from the transmission and storage segment by itself does contribute significantly to dangerous air pollution.

Response: The EPA determined that the Agency's past interpretations and actions related to the inclusion of the transmission and storage segment in the Crude Oil and Natural Gas Production source category were in error. This action focuses on the correction of these past errors and interpretations. The EPA posits that retaining this focus, in the absence of established SCF criteria for GHG emissions/methane needed to add/expand the scope of this rulemaking, is necessary and appropriate, and that doing so provides greater clarity and certainty for the regulated community.

The EPA agrees with commenters that if an appropriate assessment of the emissions from the transmission and storage segment concludes that emissions from this segment contribute significantly to the endangerment to public health or welfare, we would need to propose a separate rulemaking for the regulation of emissions from sources in this segment. However, the EPA is not, at this time, assessing whether the emissions from the transmission and storage segment contribute significantly to the endangerment to public health or welfare.

Further, the proposal preamble solicited comment regarding appropriate criteria for the EPA to consider in making a SCF. This request was made both as a broad matter and with particular reference to GHG emissions generally, and to methane emissions from the Oil and Natural Gas source category most particularly. The EPA is evaluating the responses received to its solicitation and has not yet established criteria that it would follow to make such a SCF for the transmission and storage segment as it relates to GHG emissions/methane. Discussion on comments received on the EPA's solicitation related to SCF criteria can be found in section VI.C of this preamble.

B. Rescission of the Applicability to Methane of the NSPS for Production and Processing Segments

The following summarizes some of the major comments on the EPA's proposal to rescind the methane NSPS for the production and processing segments and provides the EPA's responses. Additional discussion and comments and responses on this topic are provided above, in section V.B, and in Chapter 6 of the Response to Comments Document.

Comment: Several commenters do not agree with the proposal that section 111 of the CAA authorizes the EPA to rescind one pollutant's standards because another pollutant's standards may capture them. The EPA claims that it lacked a rational basis for its 2016 action because the requirements added in 2016 are entirely redundant with the existing NSPS for VOC. However, commenters indicate that there is not a specific provision within the CAA that expressly exempts pollutants from regulation due to overlapping control technology.

Response: Although it is true that no CAA provision explicitly authorizes rescinding requirements on the ground that they are redundant, the EPA's basis for this action is that it erred in the 2016 Rule when it concluded that it had a rational basis to regulate methane. It is not rational to impose redundant requirements, because they are not necessary and do not achieve additional health or environmental protections. This basis for the EPA's action does not depend on explicit statutory authorization.

Comment: Multiple commenters support removing methane requirements for the production and processing segments on the ground that they are redundant with the existing NSPS for VOC, for the reasons the EPA stated in the 2019 subparts OOOO and OOOOa Proposal. Another commenter states that: (1) Methane can be detected more economically than VOC and detecting VOC typically is 2 to 4 times the cost of detecting methane, (2) methane is a reliable indicator of VOC, and (3) detecting methane is safer than detecting VOC. Other commenters disagreed. One commenter states that, while the release of VOC may always be accompanied by methane, it does not follow that the release of methane will always be accompanied by the release of VOC. Some commenters make the case that the NSPS does not simply duplicate requirements for emission controls; rather, it allows, but does not require, operators to comply with both VOC and methane controls using the same practices. Another commenter states that selective technologies do exist and could be applied to reduce VOC but not methane emissions if the methane rescission is finalized. One commenter asserts that it would be arbitrary to regulate methane and VOC as the same just because the currently chosen control technologies are the same. Another commenter adds that, while the sources of VOC and methane leaks may overlap, the two have distinct pollutant effects. The commenter further adds that the urgency and stringency of desired reductions may differ considerably for the two pollutant categories and may change over time, if, for example, the need for climate change mitigation becomes more acute. The commenter suggests that the most sensible approach to regulation of emissions from oil and natural gas operations is, thus, to keep performance standards for both VOC and methane on the books, and to update those standards periodically as the science and technology evolve.

Response: The EPA acknowledges the comments but emphasizes that all of the requirements in the rule apply independently of emissions of either methane or VOC. We discussed this redundancy in detail in section IV.D of the 2019 Proposal (84 FR 50259) and in section V.B of this preamble. The EPA continues to take the position that standards of performance for methane emissions from the production and processing segments are redundant with the existing NSPS for VOC and establish no additional health protections. As explained, every affected source in the production and processing segments will continue to be subject to the same NSPS requirements for VOC as before, and those requirements will have the same impact in reducing the source's methane emissions as before the removal of methane requirements. The EPA maintains that removing the methane NSPS, while retaining the VOC NSPS, will not affect the amount of methane reductions that those requirements will achieve.

One commenter claims that methane can be detected more economically and more safely than VOC. First, it is important to note that BSER for leaking equipment is based on the use of OGI equipment, which does not require the direct measurement of VOC. It is also worthy to note that this commenter was primarily referring to economic and safety advantages of methane leak detection technologies deployed via aircraft, which is not an option currently allowed under the rule.

Comment: One commenter asserts that removing methane standards would almost certainly lead to the adoption of less protective requirements. The commenter notes that in the 2016 Response to Comment Document (p. 2–61), the EPA stated, ''that direct regulation of GHG enables the reduction of additional methane emissions beyond what could be achieved by prior VOC-focused rules.''

Response: The EPA agrees that, in theory, the direct regulation of GHG and consideration of the costs in relation to GHG reduction could result in more stringent standards and more emission reductions than if decisions were made entirely based on VOC emission reductions. The EPA also acknowledges that, for the 2016 Rule, the costs were considered both in relation to the VOC and methane emission reductions. However, the EPA disagrees with the comment that removing methane standards would ''almost certainly'' lead to less protective standards. A separate action amending NSPS subpart OOOOa (EPA–HQ–OAR–2017–0483; FRL–10013–60–OAR; FR Doc. 2020–18115), which will be finalized in the **Federal Register** of Tuesday, September 15, 2020, is an example of how this assertion by the commenter is incorrect.

In 2018, the EPA proposed amendments and clarifications to NSPS subpart OOOOa (83 FR 52056, October 15, 2018) as a result of the reconsideration of issues raised in petitions on the 2016 Rule. In 2018, the EPA proposed to decrease the monitoring frequency for well sites with average combined oil and natural gas production for the wells at the site greater than or equal to 15 barrels of oil equivalent (boe) per day from semi-annually to annually. The EPA also proposed to decrease the monitoring frequency at compressor stations from quarterly to semi-annually. For both of these situations, the standards were both for VOC and methane and the cost-effectiveness based on both VOC and methane emission reductions considered. In fact, the ''multi-pollutant'' cost effectiveness was also considered where the control costs were split between VOC and methane.

In a separate action, the EPA is finalizing the reconsideration amendments to NSPS subpart OOOOa (EPA–HQ–OAR–2017–0483; FRL–10013–60–OAR; FR Doc. 2020–18115). However, the decisions for these reconsideration amendments take into account this final policy review action, which first rescinds the methane standards for production and processing sources. Therefore, the separate reconsideration amendments are finalizing ''VOC-only'' standards based on the cost effectiveness of the reduction in VOC only. These final reconsideration amendments are more stringent than the proposed reconsideration amendments, which were based on both VOC and methane standards. Specifically, in the separate reconsideration action, the EPA is finalizing semi-annual monitoring for well sites with average combined oil and natural gas production for the wells at the site greater than or equal to 15 boe per day and semi-annual monitoring for gathering and boosting compressor stations. Therefore, in this specific situation, the elimination of methane standards resulted in more stringent standards.

Comment: Commenters state that the redundancy rationale does not consider future BSER evaluations required by CAA section 111(b)(1)(B). One commenter notes that CAA section 111(b)(1)(B) requires the EPA to periodically—every 8 years—review and, if appropriate, revise the standards established under this section (we refer to this as the 8-year review). Commenters state that removing methane will mean that the methane requirements will not be subject to this review. One commenter states that the EPA's claimed redundancy ignores that methane regulation will have unique impacts on the 8-year review, including how the Agency considers cost and benefits, which are relevant factors in the likely stringency of the standards the EPA ultimately adopts.

A commenter states that, while the BSER is largely the same for methane and VOC in the current NSPS, there is no guarantee that the BSER will not diverge for the two pollutants in the future. The commenter adds that at least one other GHG—CO_2—is emitted in significant quantities from this industry, and the EPA may determine in the future that it has a rational basis to regulate those emissions under CAA section 111(b). The commenter states that, in that case, the BSER for GHG may differ significantly from the BSER for VOC, since the former would encompass controls for methane and CO_2.

Some commenters remark specifically on the future of technologies for fugitive emission detection and the impact on redundancy. One commenter states that future developments in leak monitoring technology may be able to speciate emissions (*i.e.,* distinguish between methane and VOC), potentially allowing operators to comply with a VOC-only NSPS by controlling VOC while leaving methane emissions unabated. The commenter states that the EPA fails to consider the impact of these VOC-only technologies on future methane emissions in the absence of the current NSPS. Another commenter similarly notes that for newly developed technologies that have the potential to significantly reduce the cost of compliance for regulated entities, the mandates are not redundant. The commenter states that more than 20 percent of natural gas produced in the U.S. has little or no VOC content, making VOC an inherently poor measurement target compared to methane. The commenter adds that some emerging emissions detection technologies—such as spectroscopic sensors used for aerial and satellite surveillance—are more sensitive to methane than to VOC. The commenter adds that, by signaling that reduction of methane emissions is not a national priority, the EPA discourages the development and improvement of the best available controls for methane.

Response: The EPA acknowledges the comments made regarding potential future control technologies and how that could impact redundancy. However, methane and VOC emissions occur through the same emission points and processes, and the same currently available technologies and techniques minimize both pollutants from these emission sources. The EPA recognizes that new control technologies are under development, particularly for detecting fugitive emissions. These emerging technologies include technologies that would detect speciated fugitive emissions from oil and natural gas operations, and, in the 2019 Proposal, the EPA solicited comment on these technologies. 84 FR 50260. We received some information, but we consider it speculative and lacking in specific examples, so that we do not have enough information to evaluate these technologies at this time, much less how these technologies could impact future analyses. In short, the potential for developing future technology that will distinguish between methane and VOC emissions does not change our conclusion that methane requirements at present are redundant. If such technology does develop, the EPA could consider whether to revisit the issue of regulation of methane. By the same token, it is speculative that the 8-year review would result in different levels of controls if EPA were to consider methane emissions and requirements, along with VOC emissions and requirements. In any event, commenters on that review could raise the issue of whether methane should be controlled and whether doing so would result in more stringent VOC controls. With respect to the comment that some natural gas produced has little or no VOC content, the detection of a leak using OGI equipment is not dependent on the relative concentrations of VOC or methane, so that leaks of even low VOC gases would still be identified and required to be repaired. As discussed above, how the emergence of technology in the future could impact the requirements to detect and repair leaks is speculative at this point in time.

The EPA does not agree with the commenter that this action signals a reduction in the prioritization of the reduction in methane. As explained in section V.B.4 of this preamble and above in this section, the methane and VOC requirements are redundant, and the rescission of the methane requirements will streamline the regulation without impacting the methane reductions. With regard to discouraging the development of the best available controls for methane, future evaluations of BSER will continue to recognize the nationwide profile of natural gas, which includes VOC and methane. Therefore, improvements for the control of methane will be considered, as they also will represent improvements for VOC reductions.

Comment: One commenter expresses concern that although methane reductions would still occur even after the EPA rescinds the methane NSPS, the EPA has recently indicated its view that that reductions of co-emitted (but formally unregulated) pollutants should not factor into a benefits analysis in the same manner as those pollutants that are directly regulated. The commenter contends that, under this view, removing methane as a regulated pollutant could result in the Agency disregarding the benefits of methane emission reductions, which the EPA states are the only pollution reduction benefits from the oil and natural gas sector that the EPA can monetize (citing 81 FR 35827, June 3, 2016).

Response: The EPA maintains, as it did at proposal (84 FR 50278), that because the methane control options are redundant with VOC control options in the NSPS subpart OOOOa rule, there are no expected emission impacts or environmental disbenefits from rescinding the methane requirement for the production and processing segments. The EPA has made control decisions on the basis of the cost-effectiveness of the controls, for which monetization of health and environmental impacts other than emission reductions is not necessary. The decision whether to quantify and monetize health and environmental impacts is based upon technical judgments made within the context of developing RIAs which are written to satisfy Executive Order 12866 requirements. The EPA recognizes that in the current previous Oil and Natural Gas NSPS RIAs, the Agency has not quantified the benefits of reductions in emissions other than methane (except for quantifying the amounts of emissions reduced). These RIAs also explained these technical decisions. However, these choices have not influenced the choice of what pollutants to regulate, or the stringency of the standards promulgated, in the Oil and Natural Gas NSPS rulemakings.[71]

Comment: Several commenters state that the EPA fails to identify any way in which the alleged redundancy is problematic. The commenter notes that, while agencies may reconsider and revise their policies, before doing so they must demonstrate ''that the new policy is permissible under the statute, [and] that there are good reasons for it,'' taking into account the record of the previous rule (citing *Fox Television,* 556 U.S. at 515–16). The commenter states

[71] It should be noted that in its recently promulgated rule, ''National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units—Reconsideration of Supplemental Finding and Residual Risk and Technology Review'' (signed by the Administrator on April 16, 2020), *https://www.epa.gov/sites/production/files/2020-04/documents/frn_mats_finding_and_rtr_2060-at99_final_rule.pdf,* the EPA based its regulatory decision primarily on the amounts and costs of reductions of the regulated pollutant, but stated that it may continue to consider the co-benefits of reductions in other pollutants, as long as doing so is consistent with the applicable CAA provisions.

that the EPA has failed to provide any ''good reasons'' for why the alleged redundancy between methane and VOC requirements justifies the removal of methane requirements. The commenter explains that the EPA states in the 2019 Proposal that there are ''no expected cost . . . effects from removing the methane requirements . . .'' (citing 84 FR 50247). The commenter states that the EPA characterizes removal of methane requirements as ''less disruptive'' than removal of VOC requirements (citing 84 FR 50260), but does not explain why it is taking any ''disruptive'' action at all, especially since the 2016 Rule has been in full effect and successfully implemented for over 3 years.

Response: The fact that the air pollution controls implemented by sources in the Crude Oil and Natural Gas Production source category to comply with the VOC NSPS reduce methane emissions along with VOC emissions means that the legal requirement to control methane—that is, the methane NSPS—is redundant to the VOC requirement, and, therefore, is unnecessary. The fact that the methane NSPS does not provide benefits—it does not reduce emissions beyond what would otherwise occur—means that the EPA erred in the 2016 Rule when it determined that it had a rational basis to promulgate the methane NSPS, which is sufficient justification to rescind that regulation. As discussed elsewhere, as a predicate for promulgating NSPS for methane, the EPA was required to, and failed, to make a SCF for methane emissions from the appropriately constituted source category.

Comment: One commenter states that the EPA's true rationale for rescinding the methane NSPS is to prevent regulation of existing sources under CAA section 111(d). The commenter notes that the courts have held that administrative agencies must identify their actual reasons for policy choices, that an agency's decision may be arbitrary or pretextual if there is a substantial mismatch between the action and the rationale, and that the courts will compare the evidence for the Agency's decision with the stated explanation to discern whether such a mismatch is present (citing *Dep't of Commerce* v. *New York,* 139 S.Ct. 2551, 2575 (2019)). Noting that CAA section 111(d) imposes, as a precondition to regulation of GHG from existing sources, promulgation of NSPS for GHG under CAA section 111(b), the commenter asserts that in this case, the Agency's true rationale for rescinding the methane NSPS is to prevent regulation of methane emissions from existing oil and natural gas sources under CAA section 111(d). The commenter reviews email communications between oil and natural gas industry officials and EPA (including transition team) officials related to the Agency's decision in early 2017 to rescind the Information Collection Request (ICR) under CAA section 114 for information from existing oil and natural gas sources concerning their methane emissions, coupled with the rescission of that ICR, as evidence of what the commenter considers to be the Agency's true rationale. The commenter asserts that the Agency's stated rationale of redundancy is arbitrary and pretextual.

Response: The EPA disagrees with the commenter. The EPA's reasons for rescinding the methane NSPS are as stated in the 2019 NSPS subparts OOOO and OOOOa proposal, this preamble, and the accompanying documents: The methane NSPS is redundant to the VOC NSPS and does not achieve additional reductions. In other sections of this preamble and the supporting documents, the EPA elaborates upon this rationale and relies on it in responding to adverse comments. The Agency justified its rescission of the ICR in the rulemaking action in which it did so, and that action is separate from this rulemaking.

Comment: Several commenters address the issue of which set of NSPS to retain, methane or VOC. One commenter notes that by keeping the focus on VOC, the EPA ensures that storage tanks, which represent an important source of emissions in the production, gathering and boosting, and processing segments, remain regulated, whereas storage vessels would not be regulated under a methane-only rule. The commenter adds that the EPA data supporting NSPS subpart OOOO shows that, aside from completion activities, estimated VOC reductions from storage vessels represent the largest source of VOC reductions. *See* Regulatory Impact Analysis, April 2012 at Table 3–4. *See* 2019 Proposal, 50260 (''Some sources, such as storage vessels, are subject only to VOC requirements and not methane requirements.''). Other commenters asserted that, if redundancy is the concern for the EPA, the Agency should make methane the key pollutant and remove VOC from the requirements because this will allow for the regulation of existing sources of methane and VOC, and thereby result in reduced environmental, social, and health impacts from both pollutants.

Response: As noted in section V.B above, the EPA is rescinding the methane NSPS and retaining the VOC NSPS, rather than vice versa, because rescinding the latter would affect more facilities, and affect facilities that had been regulated for a longer period. The EPA does not agree that the methane standards should be retained instead of the VOC standards in order to retain the trigger of the CAA section 111(d) requirement to develop standards for existing sources standards. The purpose of the NSPS is to reduce emissions from new sources; as a result, the decision of which NSPS to retain should not turn on the impact on existing sources.

IX. Summary of Significant Comments and Responses on Significant Contribution Finding for Methane

This section summarizes and responds to comments on the 2019 Proposal's solicitation of comment on whether the EPA is required to make, or is authorized to make, a SCF for methane emissions from the Oil and Natural Gas Production source category as a predicate for promulgating methane NSPS.

A. Requirement for Pollutant-Specific Significant Contribution Finding

1. Promulgation of NSPS for Pollutants That the EPA Did Not Evaluate When It Listed the Source Category

Comment: Some commenters assert that CAA section 111 cannot be interpreted to authorize the EPA to promulgate NSPS for air pollutants that were not the subject of the EPA's initial determination that the source category causes or significantly contributes to dangerous air pollution. Commenters argue that in determining which pollutants the EPA should regulate from a source category under CAA section 111(b), it is reasonable to conclude that it should be limited to the pollutants that justified listing that source category for regulation in the first place. Commenters add that this interpretation provides for consistency in applying CAA section 111 across all air pollutants, that is, the EPA regulates air pollutants that it considered when it made a SCF determination for the source category, as well as air pollutants that it regulates subsequently, as long as it makes a similar SCF determination for those subsequently regulated air pollutants. A commenter adds that this approach makes sense because, to list the source category, the Agency must engage in some level of analysis to understand the nature of the emissions from that category; and that the Agency should apply the same analysis to air pollutants that it subsequently seeks to regulate. Numerous commenters state that it is anomalous for the EPA to attempt to regulate methane, as of 2016, based on a SCF determination the EPA made in 1977 and 1978, when methane was not even a regulated pollutant under the CAA.

Other commenters take the opposite view. One asserts that CAA section 111(b)(1) affords the EPA broad discretion to determine which pollutants and sources to regulate and allows the EPA to revise the NSPS to include pollutants or emission sources that were not currently regulated for a particular source category. Other commenters assert that, if the Agency failed to regulate a pollutant emitted from a listed category when it first issued standards for the source category, it must do so in a later rulemaking to achieve the purposes of the CAA, within the limitations set forth in CAA section 111. One commenter argues that CAA section 111(b)(1)(A)'s statutory factors for listing a source category provide a floor according to which the EPA must regulate a particular pollutant from that category, regardless of whether the pollutant is addressed in the initial listing decision.

Response: The EPA agrees that it promotes consistent treatment of all air pollutants subject to the NSPS to require a pollutant-specific SCF as a predicate for regulating a pollutant that the Agency did not consider at the time it made the SCF for the source category and promulgated the initial NSPS. The EPA further agrees that it is anomalous for the Agency to newly regulate an air pollutant, like methane, long after listing the source category on the basis of other pollutants, unless the Agency makes a determination concerning that pollutant that is comparable to the determination that it made when it listed the source category. These considerations support the Agency's interpretation, described in section VI above, that the Agency's authority to promulgate standards of performance for particular air pollutants under CAA section 111(b)(1)(B), along with the definition of ''standard of performance'' under CAA section 111(a)(1), must be interpreted within the context of the finding the Agency makes concerning the source category's contribution to dangerous air pollution under CAA section 111(b)(1)(A). For the same reasons, the Agency disagrees with commenters who assert that listing the source category is a sufficient predicate for subsequent regulation of air pollutants that the Agency did not address in that listing or in promulgating the initial set of standards of performance.

2. Congressional Intent

Comment: The EPA noted in the 2019 Proposal that during the 1977 CAA Amendments, the House-Senate Conference Committee Report described the revisions made to the SCF and endangerment requirements in CAA section 111 and other provisions as follows:

> Provides a uniform standard of proof for EPA regulation of air pollutants which applies to the setting of . . . criteria for national ambient air quality standards under Section 108; . . . new stationary source performance standards under Section 111; . . . new auto emission standards under Section 202; . . . regulations of fuels and fuel additives under Section 211; aircraft emission standards under Section 231.
>
> *In all future rulemaking in these areas, the Administrator could regulate any air pollutant from those sources, the emissions of which ''in his judgment cause or contribute to air pollution which may reasonably be anticipated to endanger public health or welfare.''*

H.R. Rep. No. 95–564, at 183–84 (1977) (emphasis added) (cited in 84 FR 50264). The EPA stated in the 2019 Proposal that the emphasized language is evidence that Congress intended to require the EPA (or understood that the EPA had always been required), in promulgating a pollutant-specific NSPS under CAA section 111, to make a pollutant-specific finding, as the EPA does under the other provisions mentioned in the Conference Report. *Id.* at 50264–65.

The 2019 Proposal added that the House Committee Report for the 1977 CAA Amendments included a similar statement in describing one of its purposes for rephrasing the various endangerment finding provisions: ''To provide the same standard of proof for *regulation of any air pollutant, whether that pollutant comes from stationary or mobile sources, or both,* and to make the vehicle and fuel industries equally responsible for cleaning up vehicle exhaust emissions.'' H.R. Rep. No. 94–1175, at 33 (1976) (emphasis added) (cited in *Id.* at 50265). The EPA added that the emphasized phrase could suggest that the House Committee drafters understood the SCF provision in CAA section 111(b)(1)(A) to concern the particular air pollutant subject to the NSPS, like other analogous provisions. *Id.*

Commenters offered competing interpretations of these statements in the 1977 legislative history. Some commenters agreed with the EPA's discussion, noted above. Other commenters, however, state that those Committee Report statements do not support interpreting CAA section 111 to require a pollutant-specific SCF. They assert that the 2019 Proposal was incorrect in suggesting that the 1977 CAA Amendments imposed uniform requirements on the several CAA provisions calling for contribution and endangerment determinations; rather, the commenters noted, the precise terms Congress adopted varied for each of those provisions, the terms function differently for each of the provisions, and the language in the Conference Report was a paraphrase of those provisions. For example, one commenter noted, the statement in the Conference Report does not describe how the cause-or-contribute phrase that appears in section 108 works. The commenter explained that this phrase relates not the to ''the Administrator['s] . . . regulat[ion] [of an] air pollutant from [a] source[ ],'' but instead to the Administrator's decision as to which emissions to include on the list of NAAQS pollutants. The commenter states that the NAAQS program is an area-specific program, not a source-specific one, and it grants states, not the Administrator, the primary authority to directly control emissions to achieve the NAAQS. Other commenters state that the purpose of this language in the Conference Report was to explain that Congress revised the various SCF and endangerment provisions to assure that they were each precautionary, not to assure that they each required a pollutant-specific SCF. Another commenter notes that these revisions to the SCF and endangerment provisions were made to CAA section 111(b)(1)(A), which covers source category listings, but not to CAA section 111(b)(1)(B), which requires the EPA to promulgate standards of performance. The commenter asserts that, if Congress had wanted to make clear that the EPA may not issue standards under CAA section 111(b)(1)(B) unless it had made a pollutant-specific SCF, it could have achieved that result by amending CAA section 111(b)(1)(B) in addition to CAA section 111(b)(1)(A), but it chose not to do so. The commenter asserts that ''[w]hen Congress amends one statutory provision but not another, it is presumed to have acted intentionally'' (citing *Gross* v. *FBL Fin. Servs., Inc.,* 557 U.S. 167, 174 (2009)). Other commenters contend that the Conference Report is at best ambiguous as to whether the source or the air pollutant must be the focus of the ''cause or contribute'' finding, and, in any event, cannot overcome what they describe as the plain meaning of the statute.

Response: We appreciate the different perspectives that commenters provide on the above-quoted statements in the legislative history. Because these statements explicitly describe CAA section 111, along with other CAA provisions, as requiring a pollutant-specific SCF, we think that they can fairly be read to indicate that interpreting CAA section 111 to require, or at least authorize the Administrator to require, a pollutant-specific SCF is consistent with Congressional intent. It was not necessary for Congress to amend CAA section 111(b)(1)(B) explicitly to require a pollutant-specific SCF because its provisions, read in context, already required, or at least authorized the EPA to require, that SCF. None of the commenters point to anything in the legislative history that indicates Congress did not intend to require a pollutant-specific SCF under CAA section 111.

3. Comparison With Other CAA Provisions That Generally Include a Cause or Contribute Finding on a Pollutant-Specific Basis

In the 2019 Proposal, the EPA noted that when Congress enacted CAA section 111 as part of the 1970 CAA Amendments, Congress also enacted several other provisions that required the EPA to promulgate regulations for certain pollutants or certain sources, and that in each of these provisions, Congress required the EPA to make an endangerment or cause or contribute finding, and, further, required the EPA to make the relevant finding on a pollutant-specific basis. The EPA solicited comment on the relevance of whether any of these other provisions for whether CAA section 111 could be interpreted to require, or at least authorize, a pollutant-specific SCF. 84 FR 50263 and 64, 50265 n.74 (discussing, among others, CAA sections 108(a)(1)(A) and (B), 115(a), 202(a)(1), 211(c)(1), 231(a)(2)).

Comment: Some commenters stated that interpreting CAA section 111 to not require a pollutant-specific SCF renders that section anomalous compared with other CAA provisions that premise the EPA's regulatory authority on a pollutant-specific ''cause or contribute'' finding. One commenter suggests that the primary difference between CAA section 111(b) and certain other CAA provisions is that CAA section 111(b) requires that the source category cause or contribute ''significantly'' to air pollution endangering public health or welfare. The commenter states that this implies that the EPA should face a higher burden to justify regulating each specific pollutant under CAA section 111, not a lower burden that allows the EPA to regulate every pollutant from the source category so long as just one meets the statutory criteria.

Other commenters take the opposite position. They assert that the requirements for pollutant-specific cause-or-contribute findings under other CAA sections shows that Congress knew how to require pollutant-specific findings when it intended to do so, and it evidently did not intend to do so under CAA section 111. Another commenter adds that Congress clearly chose to use different phrasing in different sections because it amended all these provisions at the same time in the same section of the 1977 CAA Amendments. From this, the commenter infers that Congress chose to use different phrasing in CAA section 111 than in the other provisions.

One commenter distinguishes CAA section 111 from other CAA provisions that the EPA cited because the latter provisions identify the particular category or class of sources as requiring regulation, and the EPA proceeds to regulate particular pollutants from those sources that it determines cause or contribute to dangerous air pollution. The commenter states that these provisions include CAA section 183(f)(1)(A) (addressing standards applicable to the loading and unloading of tank vessels) and CAA section 213(a)(1) through (4) (governing emission standards for new nonroad engines and vehicles). In contrast, the commenter explains, CAA section 111 does not pre-define any source category for regulation, but instead directs the EPA to fulfill this obligation. The commenter asserts that it is implausible that Congress would rest on any implication from CAA section 111(b) that the EPA must make an additional SCF for each pollutant regulated. The commenter adds that Congress knew how to provide for such an additional finding because CAA section 213(a)(4) requires one for an air pollution problem that (1) emissions from new nonroad engines or vehicles contribute significantly to and (2) emissions from classes or categories of new nonroad engines or vehicles cause or contribute to.

The commenter also identifies another distinction between CAA section 111 and some of the other provisions the EPA cites, which is that the latter address a specific kind or sub-class of pollutants. For example, according to the commenter, CAA sections 108(a)(1)(A) and (B) charges the Administrator with determining which emissions should be classified as criteria pollutants subject to the NAAQS because they contribute to dangerous air pollution and are emitted by numerous diverse mobile or stationary sources, and CAA section 115(a) concerns specific instances in which a pollutant or pollutants that originated in the U.S. cross an international border and endanger public health or welfare in a foreign country. The commenter suggests that a pollutant-specific contribution finding is sensible for these programs: The Agency's task is to identify all the air pollutants that contribute to an air pollution problem in order to determine whether they should qualify as NAAQS pollutants or whether they are harming public health or welfare in another country. The commenter states that this approach is distinct from CAA section 111, which is oriented toward source categories and requires them to achieve an emission limitation that reflects deployment of the BSER for dangerous pollutants, and which does not focus on or even reference any particular type or sub-class of pollutants.

Response: The EPA appreciates the commenters' perspectives on whether the other provisions in the CAA that explicitly require a pollutant-specific contribution finding suggest that Congress did or did not intend that CAA section 111 do so as well. For the reasons described in section VI above, by their terms, CAA section 111(b)(1)(B), in conjunction with CAA section 111(a)(1), and in the context of CAA section 111(b)(1)(A), requires, or at least authorizes the EPA to require, a pollutant-specific SCF as a predicate to promulgating a NSPS for that pollutant, notwithstanding the fact that Congress did not explicitly require such a determination in CAA section 111(b)(1)(B). We believe that this interpretation is consistent with the fact that Congress included requirements for a pollutant-specific cause-or-contribute finding in other CAA provisions. It is true, as the EPA recognized in the 2019 Proposal, 84 FR 50264, and as commenters noted, these other provisions differ from CAA section 111(b) in certain respects, but they differ from each other as well. For example, in CAA sections 213(a)(2), (3), and (4), Congress required a two-step determination, unlike in other provisions. In addition, the fact that CAA section 111 delegates to the EPA the task of identifying the source category for regulation, whereas other provisions themselves identify the source category, explains why it is necessary for the EPA to make a SCF for the source category (it is to assure that the source category merits regulation), but does not provide a compelling reason why the EPA should not also, when it subsequently promulgates a NSPS for a particular pollutant, make a SCF for that pollutant. The important point from comparing these various provisions is that Congress recognized the utility of a pollutant-specific cause-or-contribute finding in a range of circumstances, including a range of regulatory schemes for a range of industries that emit a range of air pollutants that affect a range of geographic areas (including other nations, under CAA section 115). That supports interpreting CAA section 111 to include a pollutant-specific finding as well.

Comment: A commenter asserts that a two-step process in which the EPA makes a SCF for the source category and then for the particular pollutant is anomalous since the other provisions the EPA cites involve only a one-step process. The commenter adds that the two-step process is anomalous because the first step—listing the source category on grounds that it contributes significantly to dangerous air pollution—becomes unnecessary if the EPA must also determine that particular pollutants contribute significantly to dangerous air pollution. The commenter further suggests that a two-step scheme creates two additional anomalies: (1) The EPA might determine that emissions from a source category significantly contribute, but might not be able to determine that any individual air pollutant significantly contributes, and, therefore, might not be able to regulate at all; and (2) the EPA might determine that emissions from a source category significantly contributes, but might be able to regulate only an insignificant portion of those emissions. Another commenter asserts that the other provisions require only a cause-or-contribute finding, not a cause-or-contribute significantly finding, which casts doubt on the EPA's interpretation that CAA section 111(b) requires the latter type of finding.

Response: As noted above, CAA sections 213(a)(2), (3), and (4) impose a two-step process. The commenter's claimed anomalies may be theoretically possible but are highly unlikely to actually occur. The source categories that the EPA lists under CAA section 111(b)(1)(A) are industrial sources that the EPA has determined contribute significantly to dangerous air pollution and that typically emit more than one air pollutant; it is highly unlikely that none of such a category's air pollutants, or only a minor portion of its pollutants, would contribute significantly to dangerous air pollution, and the commenter does not claim that either of those situations is true of any of the some 76 source categories that the EPA has listed. As noted below, the rational-basis approach creates its own set of anomalies. Contrary to the commenter's views, a two-step process under CAA section 111(b)(1), under which the EPA makes a SCF for the source category and a SCF for the particular air pollutants, does not render the first step unnecessary. As the EPA explained in section VI above, the EPA has generally evaluated the contributions of the source category and the air pollutants it emits at the same time, and it has generally relied on data concerning the individual air pollutants to make the SCF for the source category. As a practical matter, then, the EPA generally would need to make a SCF for an air pollutant separately from the SCF for the source category only when the EPA seeks to promulgate a NSPS for an air pollutant that the EPA did not consider when it listed the source category. It is true, as the commenter noted, that the other provisions cited by the EPA in the 2019 Proposal and discussed by the commenters require a pollutant-specific cause-or-contribute finding, and not a SCF, but interpreting CAA section 111(b)(1)(B) to require, or at least authorize the EPA to require, a SCF is consistent with the requirement for a SCF under CAA section 111(b)(1)(A). Section 111(b)(1)(B) of the CAA is not unique in this regard—in the 1990 CAA Amendments, Congress revised the Good Neighbor Provision, CAA section 110(a)(2)(D)(i)(I), to require that SIPs prohibit sources from emitting air pollutants in amounts that will ''contribute significantly'' to nonattainment downwind.

4. Rational Basis Approach

Comment: Numerous commenters agree with, and elaborate on, the concerns that the EPA expressed in the 2019 Proposal about the rational basis approach (discussed in section VI of this preamble). Some note that the approach is not tied to any language in the CAA, is not based on any statutory criteria, and, thus, is largely undefined. They state that it does not meaningfully limit the EPA's authority and, therefore, injects confusion into the regulatory process. One commenter asserts that it makes no sense to regulate unless there is assurance that the regulation will produce the desired benefits, which may be accomplished only by analyzing emissions on a pollutant-specific basis. Other commenters add that the rational basis standard allows the EPA to rely on a SCF made for a source category decades ago for a different pollutant in order to justify regulating any pollutant from the category—even pollutants that do not cause or significantly contribute to endangerment. Many commenters assert that, without a pollutant-specific SCF, the EPA would have unfettered discretion to add pollutants no matter how minimal the contribution or how benign the impacts to public health and welfare, and that this could result in potentially costly, disruptive, and inefficient regulations on an industry. Another commenter points to anomalies that could result from the rational basis approach: (1) The approach could lead to a case where the EPA would be free to regulate all pollutants from a source category, even though only one of the pollutants was found to contribute to endangerment; and (2) it could result in disparate treatment of similarly emitting source categories: For example, Source Categories 1 and 2 may both emit Pollutant A in equal amounts that do not significantly contribute to endangerment, while Source Category 1 also emits Pollutant B in an amount that does significantly contribute to endangerment. The commenter states that, under the rational basis approach, the EPA would have the authority to list Source Category 1 and regulate emissions of Pollutant A from it, but would not have the authority to list Source Category 2, and, therefore, would not be able to regulate emissions of Pollutant A from it, even though each Source Category's emissions of Pollutant A present identically insignificant risks. The commenter contends that requiring a SCF for each pollutant would prevent these anomalies. In contrast to the vague rational basis standard, other commenters state, CAA section 111(b) provides clear criteria for whether the EPA is authorized to regulate a source's emissions of a pollutant: The endangerment and SCF determinations for listing a source category. Other commenters add that CAA section 111(b) established this rigorous finding as necessary to justify the EPA's authority to promulgate nationwide standards, and that only a pollutant-specific SCF, not a rational basis standard, would maintain that rigorous approach.

Other commenters assert that the requirement of a rational basis standard is appropriate. They note that the standard is equivalent to the ''arbitrary and capricious'' standard. They state that CAA section 111(b)(1)(A), by its terms, applies the endangerment and SCF findings to the source category as a whole, and not to each newly-regulated pollutant emitted from a previously-listed source category, and that, given that many decisions delegated to the EPA are governed by a default rational basis standard, it is reasonable to conclude that Congress could have intended that standard to govern the regulation of subsequent pollutants from previously-listed sources in the absence of any other prescription for how the EPA is to make the decision. Commenters further state that the arbitrary and capricious standard is not undefined. Rather, one commenter says, the Supreme Court, in defining ''[t]he scope of review under the 'arbitrary and capricious' standard,'' has explained that ''the agency must examine the relevant data and articulate a satisfactory explanation for its action including a rational connection between the facts found and the choice made'' (citing *Motor Vehicle Mfrs. Ass'n of U.S., Inc.* v. *State Farm Mut. Auto. Ins. Co.,* 463 U.S. 29, 42–43 (1983)). The commenter adds that the Court affirmed that it ''may not set aside an agency rule that is rational, based on consideration of the relevant factors and within the scope of the authority delegated to the agency by the statute.'' [72] The commenter adds that this standard applies whether or not Congress has expressly specified the criteria relevant to the Agency's decision. A commenter further notes that under the ''arbitrary and capricious'' standard, the Court has identified certain factors that the EPA must consider in promulgating emission standards under CAA section 111(b) (citing *Sierra Club* v. *Costle,* 657 F.2d 298, 326 (D.C. Cir. 1981). A commenter adds that the Court remanded the Lime Kiln NSPS under the ''arbitrary and capricious'' standard, and quoted from the legislative history of the 1977 Amendments, which indicated Congress's intent that the arbitrary and capricious standard to have teeth: ''With respect to the 'arbitrary and capricious' scope of review retained in these amendments, the conferees intend that the courts continue their thorough, comprehensive review which has characterized judicial proceedings under the CAA thus far'' (citing *Nat'l Lime Ass'n* v. *EPA,* 627 F.2d 416, 452 (D.C. Cir. 1980) (quoting H.R. Conf. Rep. No. 564, 95th Cong., 1st Sess. 178 (1977))). The commenters contend that, under the arbitrary and capricious standard, an EPA decision to promulgate a standard of performance for a benign or harmless substance would fail.

Response: In the 2019 Proposal, the EPA acknowledged that the rational basis test ''offers some protection against arbitrary or capricious decisions by the EPA.'' 84 FR 50263. However, CAA section 111 includes no explicit criteria to guide the application of such a test, and in the times that the EPA has used the test, the EPA has not attempted to articulate criteria or metrics to guide it, and rather, has relied on facts and circumstances. In those respects, the rational basis test is largely (or wholly) undefined and could potentially incorporate a wide range of considerations and lead to inconsistent results. This creates uncertainty for the regulated industry and other stakeholders over whether particular additional pollutants will be regulated or not. The EPA has concluded that the standard is not appropriate for determining the air pollutants for which it will promulgate standards of performance under CAA section 111(b)(1)(B) because of statutory context: CAA section 111(b)(1)(A) makes clear that before the EPA may regulate any air pollutants from major new sources, it must determine that the source category whose sources emit the air pollutants cause or contribute significantly to dangerous air pollution. This is a rigorous predicate for regulation. It is not consonant with this rigorous predicate for the Agency to proceed to regulate the individual air pollutants based only on a rational basis determination. Rather, requiring the Agency to make a SCF determination is consistent with CAA section 111(b)(1)(A). In addition, the SCF determination is better defined because it is focused directly on the extent of the air pollutant's impact on dangerous air pollution, and it provides a metric for assessing that extent: The air pollutant causes or contributes significantly to that air pollution. These metrics more clearly cabin the EPA's discretion.

5. Impacts on the CAA Section 111 Program if a Pollutant-Specific SCF Is Needed

Comment: Commenters state that for more than 4 decades the EPA has interpreted CAA section 111(b)(1) to require a SCF as a prerequisite only for the initial listing of a source category. Commenters contend that, if the EPA now contradicts its past practice and interpretation and undermines or repeals what they describe as the dozens of NSPS it has issued during that time, entities that are subject to new and existing source performance standards under CAA section 111, as well as for the states and local agencies that implement those standards, and other stakeholders, will face regulatory uncertainty and harm to their reliance interests. Commenters add that the EPA's reversal of precedent would also call into question the validity of state implementation plans that were based in part on the continued existence of regulation under CAA section 111(b), as well as the validity of state and Federal plans based on CAA section 111(d) guidelines, and conclude that health and welfare will suffer. Commenters express concern that the EPA fails to provide an analysis of the potential impacts on the overall CAA section 111 program if a pollutant-specific SCF is needed. Commenters assert the EPA should not alter what they describe as the EPA's longstanding interpretation that a pollutant-specific SCF is not needed without first completing a full analysis of impacts such a change would have on existing CAA section 111 rules and soliciting further public participation through a separate notice-and-comment rulemaking process. One commenter contends that, even if the EPA begins requiring a pollutant specific contribution finding, this should not affect the validity of previously, lawfully issued NSPS and CAA section 111(d) guidelines and state plans.

Response: The EPA has listed some 76 source categories and promulgated over 100 standards of performance for them. In the vast majority of cases, the EPA identified the pollutants of concern at the time that it listed the source category or when it promulgated the initial set of standards of performance contemporaneously with the listing or shortly thereafter. It is only in recent rulemakings concerning GHG that stakeholders have expressed concerns that the EPA had not considered GHG when listing the source category, and, thus, had not made determinations for GHG consistent with the determinations that the EPA made to justify regulation of other pollutants from the source categories. Accordingly, the EPA disagrees with commenters who are concerned that interpreting CAA section 111 to require a pollutant-specific SCF will undermine numerous NSPS, with adverse effects for other CAA control programs. In addition, the rational basis approach, under which the EPA promulgates a standard of performance for a pollutant upon determining that it has a rational basis for doing so, cannot be considered to be long-established. The EPA clearly articulated this standard for the first time to justify regulation of a previously unregulated

[72] By the same token, a commenter notes that the EPA explained the rational basis test in its response to comments on the 2016 Rule as follows: ''the EPA's use of the phrase 'rational basis' . . . explains how the agency's actions are supported by the record and is a reasonable exercise of the EPA's broad authority under section 111'' (citing the EPA's Response to Public Comments at 2–16, Docket ID Item No. EPA–HQ–OAR–2010–0505–7632 (May 2016).

air pollutant in the 2015 EGU GHG NSPS rule, and then again in the 2016 Rule. The EPA considers that the present rulemaking has provided a full opportunity for the public to respond to the solicitation of comment on the pollutant-specific SCF interpretation.

B. Significant Contribution Finding in 2016 Rule

1. 2016 SCF for Methane Emissions From the Oil and Natural Gas Source Category

Comment: Several commenters contend that oil and gas methane emissions are too small to be considered ''significant.'' These commenters cite as support that the contribution of oil and gas to total U.S. GHG emissions is only 3 percent, that U.S. methane emissions are only 7 percent of global methane emissions, that U.S. methane emissions are only 1 percent of global GHG emissions, and that estimated impacts of the 2016 Rule would be to reduce methane concentrations in 2100 by 0.12 percent and temperatures by less than a thousandth of a degree. Other commenters assert that, if a SCF for methane emissions from the Oil and Natural Gas source category were required under the statute, the EPA fully satisfied this obligation in the 2016 Rule. Several commenters assert that, even if the EPA eliminates the transmission and storage segment from the source category, the 2016 SCF remains appropriate and binding. A commenter notes in the 2019 Proposal the production and processing segments account for 1.8 percent of global methane and 0.3 percent of total global GHG and states this is equal to or greater than the total methane emissions from all but eight countries around the world. The commenter asserts that these totals are significant by any measure. One commenter states that because climate change is a global phenomenon, small percentage changes are relevant and addressing a large number of smaller sources will ultimately reduce the rate of climate change. The commenter adds that to solve a global problem, reductions of a fraction of a percent are substantial and important (citing 2016 Rule's Response to Comments Document, Docket ID Item No. EPA–HQ–OAR–2010–0505–7632). One commenter states that, if the production and processing segments were listed as an individual methane source, it would still be larger than every other source currently listed apart from enteric fermentation. One commenter notes that in light of methane's 20-year GWP of 87, methane from the domestic sources accounts for 9.3 percent of total U.S. GHG emissions and 1.2 percent of global GHG emissions. One commenter states that the transmission and storage segment emits 16.8 percent of the source category's total GHG emissions and it would be arbitrary and capricious for the EPA to undermine its 2016 SCF by removing from that source category facilities that emit only a minority of the pollutants.

Response: The EPA agrees with commenters that the 2016 Rule failed to provide a pollutant-specific SCF as a prerequisite to imposing NSPS regulations for methane emissions. The SCF determination made in the 2016 Rule was on the basis of methane emissions from the production, processing, transmission and storage segments. In this action, the EPA is removing the transmission and storage segment from the source category. The 2016 Rule did not assess whether methane emissions from the production and processing segments alone cause or contribute significantly to dangerous air pollution; thus, we find that the 2016 Rule's determination is not adequate. In addition, the EPA has yet to makes an appropriate determination that methane emissions from the Oil and Natural Gas Production source category cause or contribute significantly to dangerous air pollution. The EPA appreciates the commenters' views concerning the amounts and impacts of methane emissions from the transmission and storage segment, as well as the production and processing segments, but until the EPA itself reviews and assesses those amounts of emissions, it cannot make a determination as to whether methane emissions from the production and processing segments contribute significantly to dangerous air pollution.

2. Identification of the Standard for Determining Significance

Comment: Commenters responded to the EPA's solicitation of comment concerning whether, as a matter of law, under CAA section 111, the EPA is obligated to identify the standard by which it determines whether a source category's emissions contribute significantly, and whether, if not so obligated, the EPA nevertheless fails to engage in reasoned decision-making by not identifying that standard. Some commenters stated that the EPA must identify the standard by which it determines whether a source category's emissions ''contribute significantly.'' They asserted that, in order to not be arbitrary and capricious, an agency must articulate a reasonable explanation for the actions it takes, and that as a result, the EPA should establish what constitutes ''significant'' contribution for purposes of CAA section 111(b). They note that the EPA has done so for other programs that require a similar showing, such as CAA sections 110(a)(2)(D)(i), 189(e), and 213 (citing 76 FR 48208, 48236 and 37 (August 8, 2011) (Cross-State Air Pollution Rule)). Other commenters assert there is no indication that Congress intended that the EPA must establish such a standard before making a SCF and that the EPA has made SCFs for dozens of source categories over almost 50 years without having established such a standard. They added that in the past, the EPA has appropriately relied on a facts and circumstances analysis and that it would be irrational to adopt a standard or threshold because different air pollutants have different effects on health and/or welfare, as well as different geographic trajectories.

Response: The EPA appreciates these comments, as well as the additional ones noted in the Response to Comments Document. They will inform the Agency's future consideration of this issue. As explained above, the Agency has concluded that it must identify a standard for ''contribute significantly'' in order to make a SCF for a source category, to ensure not only that the public is on notice of the criteria that the Agency uses in making such determinations but also that the Agency itself is acting consistently in making such determinations. However, it is not necessary to resolve the specific content of this standard in this rulemaking because, as discussed above in section VI of this preamble, the EPA is rescinding the SCF for methane from the Oil and Natural Gas Production source category that the Agency made in the 2016 Rule, on the ground that the scope of the source category inappropriately included the transmission and storage segment.

C. Criteria for Making a Significant Contribution Finding Under CAA Section 111

Comment: Several commenters responded to the EPA's solicitation of comment regarding criteria for the EPA to consider in making a SCF. Some recommend that the EPA defer any action on SCF criteria and instead address this question in a future advance notice of proposed rulemaking, ICR, and/or proposed rulemaking. One commenter adds that deferring the issue would allow the EPA to focus on finalizing the core rulemaking and to streamline issues in any future legal challenge to a final rule. Some commenters discuss other contexts under the CAA in which the Agency has interpreted and applied similar language to governing the SCF determinations under CAA section 111(b)(1)(A). For example, these commenters discuss factors suggested by past EPA action under CAA sections 189(e) and 213(a)(2), (3), and (4). Some commenters suggest specific criteria that the EPA could consider, including, among others, consideration of the 1979 source category listing methodology, factors related to climate change, all factors relevant to a source category's contribution on a case-by-case basis, accumulation in the atmosphere of pollutants, projected future emissions, and consistency with the goal of protection of the Nation's air resources. We summarize these comments at greater length in the Response to Comments Document.

Response: The EPA acknowledges the commenters' statements. As pointed out in the proposal, the EPA does not intend for these comments to inform the finalization of this rule, but rather to inform the EPA's actions in future rules. Therefore, the EPA is not evaluating the merits of comments on these topics at this time. However, the Agency will look at the details provided in these comments when considering future action in making a SCF.

X. Summary of Significant Comments and Responses Concerning Implications for Regulation of Existing Sources

A. Existing Source Regulation Under CAA Section 111(d)

Comment: Several commenters agree with the statements in the 2019 Proposal that the EPA's rescission of the applicability of the NSPS to methane emissions for the sources in the Crude Oil and Natural Gas Production source category that are currently covered by the NSPS would have the consequence that the EPA would no longer be authorized to regulate existing sources of the same type in the source category under CAA section 111(d).

However, other commenters assert that the 2016 Rule regulation of methane from the oil and natural gas sector has already triggered a mandatory duty for the EPA to develop CAA section 111(d) EG for existing sources within that sector. They state that the EPA's 2009 endangerment finding for GHG emissions and its 2016 rational basis determination and pollutant-specific endangerment/SCF for methane emissions from the Oil and Natural Gas Production source category obligate the EPA to regulate such emissions not just from new sources under CAA section 111(b), but also from existing sources under CAA section 111(d).

Response: The EPA agrees that following promulgation of the methane NSPS in the 2016 Rule, the EPA was obligated to develop EG under CAA section 111(d) for existing sources of methane in the source category. However, that obligation ends with the rescission of those NSPS. Section 111(d)(1) of the CAA provides by its terms that the EPA is authorized to promulgate guidelines for regulation of any existing source ''to which a standard of performance under this section would apply if such existing source were a new source.'' Once the EPA has rescinded the methane NSPS, existing sources of methane would no longer be subject to such an NSPS if they were new sources. As a result, from the time of the rescission forward, the EPA would no longer have authority to promulgate guidelines to regulate those sources. Nothing in CAA section 111(d) indicates that once the EPA promulgates NSPS that trigger an obligation to regulate existing sources, that obligation remains in place even after the NSPS has been rescinded.

Comment: As discussed in the proposal preamble for this action, the EPA interprets CAA section 111(d) as not permitting a CAA section 111(d) existing source regulation to be developed as a result of the NSPS for VOC emissions from new sources in the Crude Oil and Natural Gas Production source category under CAA section 111(b). Specifically, the EPA stated that VOC do not qualify as the type of air pollutant that, if subjected to a standard of performance for new sources, would trigger the application of CAA section 111(d) the pollutants excluded from regulation under CAA section 111(d) include pollutants which have been included on the EPA's CAA section 108(a) list. VOC are not expressly listed on the EPA's CAA section 108(a) list, but they are precursors to ozone and PM, both of which are listed CAA section 108(a) pollutants. The definition of ''air pollutant'' in CAA section 302(g) expressly provides that the term ''air pollutant'' includes precursors to the formation of an air pollutant ''to the extent that the Administrator has identified such precursor or precursors for the particular purpose for which the term 'air pollutant' is used.'' Based on this ''particular purpose'' phrasing, it is appropriate to identify VOC as a listed CAA section 108(a) pollutant for the particular purpose of applying the CAA section 108(a) exclusion in CAA section 111(d) [hereinafter referred to as the EPA's ''VOC exclusion argument'']. 84 FR 50272. Comments provided on the proposal both agree and disagree with this interpretation. These comments are provided below.

Commenters that agree with the EPA's interpretation assert that the statute is clear that a source category cannot be subject to CAA section 111(d) emission standards for ''any pollutant . . . for which air quality criteria have . . . been issued or which is . . . included on a list published under'' CAA section 108(a). The commenters state that while VOC are not themselves directly on the list of criteria pollutants under CAA section 108, the EPA has designated them as precursors for ozone and PM, both of which are listed CAA section 108(a) criteria pollutants. The commenters add that the CAA defines ''air pollutant'' to include ''any precursors to the formation of any air pollutant, to the extent the Administrator has identified such precursor or precursors for the particular purpose for which the term 'air pollutant' is used,'' and because the ''particular purpose'' of the term ''air pollutant'' in CAA section 111(d) is to identify pollutants that are already subject to regulation under the NAAQS program, it is appropriate to conclude that VOC are one of the ''air pollutants'' covered by this exclusion.

Conversely, several other commenters disagree with the EPA's interpretation that CAA section 111(d) does not require that existing source regulation be developed as a result of the NSPS for VOC emissions from new sources in the Crude Oil and Natural Gas Production source category under CAA section 111(b). One commenter notes that the EPA first argues that VOC are ''regulated under the CAA's NAAQS/SIP program'' because they are precursors to listed pollutants ozone and PM, pointing to provisions of the CAA relating to requirements for ozone non-attainment areas that explicitly call for reductions in VOC emissions. The commenter asserts, however, that the statutory test for whether a pollutant is excluded is not whether it is ''regulated under'' CAA section 108 or CAA section 110, but rather the test is whether air quality criteria have been issued for the pollutant of concern, or the pollutant has been listed under CAA section 108. The commenter asserts that neither of these is true here for VOC, as the only pollutants for which air quality criteria have been issued or included on a list published under CAA section 108(a) are SO_2, PM_{10} and $PM_{2.5}$, CO, ozone, NO_X, and lead.

One commenter contends that the proposal VOC exclusion argument contradicts the Agency's own position in other regulations and notes that in 1996 the EPA finalized parallel rulemakings for new and existing municipal solid waste (MSW) landfills under CAA sections 111(b) and 111(d), respectively. The commenter states that pollutants deemed harmful to human health emitted from MSW landfills included methane, VOC, HAP, and odorous compounds, collectively termed ''landfill gas.'' The commenter notes that the EPA chose to use non-methane organic compounds (NMOC), which includes VOC, as a surrogate for landfill gas in its setting standards of performance and EG for new and existing MSW landfills under CAA sections 111(b) and 111(d). The EPA updated these regulations in 2016 (2016 Standard), with its new EG ''expected to significantly reduce emissions of LFG [landfill gas] and its components, which include methane, VOC, and hazardous air pollutants (HAP).'' The commenter states that the EPA noted that reducing methane had become more important since the prior 1996 rulemaking, which had focused on NMOC (including VOC) ''because NMOC contain[ed] the air pollutants that at that time were of most concern due to their adverse effects on public health and welfare.'' The commenter adds that, as such, the 2016 Standard was focused on ''reducing [both] the NMOC and methane components of LFG.'' The commenter provides that the EPA acknowledged VOC was a precursor to criteria pollutants $PM_{2.5}$ and ozone, but nowhere did the EPA make the argument the Agency now raises that VOC status as a precursor means that it is not subject to regulation under CAA section 111(d).

Response: First, with respect to the comment that the EPA has applied a ''regulated under CAA 108'' test rather than the ''listed under CAA 108'' test that is stated in the statute, this comment misstates the EPA's argument. The EPA's conclusion is that VOC are included within the CAA section 108(a) listings for ozone and $PM_{2.5}$ for the particular purpose of applying the CAA section 108(a) exclusion in CAA section 111(d). The ''regulated under CAA 108'' point is one of the reasons why the EPA has concluded that it is appropriate to consider VOC to be part of the CAA section 108(a) listings for ozone and PM 2.5 for this purpose—because VOC are regulated through the NAAQS implementation program, and thus there is no gap in the CAA regulation of VOC that needs to be covered by CAA 111(d) regulation. In other words, we are not concluding that VOC are excluded from CAA 111(d) regulation because they are regulated under the NAAQS implementation program. Instead, we are concluding that VOC are excluded from 111(d) regulation because they are part of the CAA 108(a) listings for ozone and $PM_{2.5}$ for the purpose of applying CAA section 111(d), and we reach that conclusion based in part on the fact that VOC are regulated through the NAAQS implementation program.

Second, the argument that EPA's regulation of municipal solid waste (MSW) landfill emissions (sometimes referred to as ''landfill gas'') under CAA 111(d) contradicts EPA's conclusion that VOC cannot be regulated under CAA 111(d), because MSW landfill emissions landfill includes VOC among its components, is incorrect. The EG and standards of performance for MSW landfills that were originally promulgated in subparts Cc and WWW of part 60 and subsequently in subparts Cf and XXX regulate only ''MSW landfill emissions,'' not the individual components of landfill gases. *See* 40 CFR 60.30c through 60.36c; 40 CFR 60.30f through 60.41f; 40 CFR 60.750 through 60.759, and 40 CFR 60.760 through 60.769. Both the regulatory text in these subparts and the EPA's preamble discussion explicitly address this issue and clarify that ''MSW landfill emissions'' is a single designated pollutant and the only pollutant subject to regulation by these subparts.

For example, the regulatory text of 40 CFR part 60, subpart Cc, clarified that it contains guidelines for the control of ''certain designated pollutants'' and identifies ''MSW landfill emissions'' as the pollutant to be controlled by the state plans. 40 CFR 60.30c and 60.33c(a). The same is true for 40 CFR part 60, subpart Cf. 40 CFR 60.30f (subpart establishes requirements for ''designated pollutants), 60.33f(a) (pollutant to be controlled is ''MSW landfill emissions''). Similarly, 40 CFR part 60, subparts WWW and XXX, require affected sources to collect and control landfill gases, and each defines ''MSW landfill emissions'' as ''gas generated by the decomposition of organic waste deposited in an MSW landfill or derived from the evolution of organic compounds in the waste.'' 40 CFR 60.751; 40 CFR 60.761. This definition in each subpart makes clear that the regulated pollutant is confined to emissions that originate from an MSW landfill.

Further, in proposing the MSW regulations in 1991, the EPA was explicit that it was regulating only MSW landfill emissions collectively, and not the individual components of those emissions. The EPA stated the following in the preamble to the proposed rule:

> The pollutant to be regulated under the proposed standards and guidelines is ''MSW landfill emissions.'' Municipal solid waste landfill emissions, also commonly referred to as ''landfill gas,'' is a collection of air pollutants, including methane and NMOC's [non-methane organic compounds], some of which are toxic. The composite pollutant is proposed to be regulated under section 111(b), for new facilities, and is proposed to be the designated pollutant under section 111(d), for existing facilities.

56 FR 24468, 24470 (May 30, 1991). In additional discussion, the EPA explained the following:

> The EPA views these emissions as a complex aggregate of pollutants which together pose a threat to public health and welfare based on the combined adverse effects of the various components. . . . [T]he exact composition of MSW landfill emissions can vary significantly from landfill to landfill and over time. Although the types of compounds are typically the same, the complex mixture cannot be characterized quantitatively in terms of single pollutants. The EPA thus views the complex air emission mixture from landfills to constitute a single designated pollutant.

Id. at 24474–24475. Thus, the argument that VOC or any other of the individual components of landfill gases are separately regulated under these provisions is incorrect and inconsistent with the regulatory text and record for these subparts.

Comment: The proposal preamble for this action cited CAA section 112(b)(2) and argued that the ''except'' phrasing of CAA section 112(b)(2) suggests that air pollutants which are ''listed under section 7408(a)'' can be read to include precursors to the pollutant that is listed under CAA section 108(a). The EPA provided that otherwise the pollutants that are described in the second part of the sentence (pollutants that meet the listing criteria and are precursors to a CAA section 108(a) pollutant) would not be an exception to the prohibition in the first part of the sentence. 84 FR 50272.

One commenter contends that the EPA's analogy to CAA section 112 to ostensibly demonstrate that Congress would have explicitly subjected precursors to regulation in CAA section 111(d) if it wanted to, because it did so in CAA section 112 is inapposite here. The commenter states that, first, as the EPA acknowledges, Congress provided a flexible definition of ''air pollutant'' depending on ''the particular purpose for which the term 'air pollutant' is used.'' The commenter states that the particular purpose for which the term ''air pollutant'' is used in CAA section 112 is quite different than in CAA section 111(d). The commenter notes that the relevant statutory provision in

CAA section 112 excludes from regulation as a HAP any ''air pollutant[s] listed under section [108(a)] . . . except that . . . precursor[s] to a pollutant which [are] listed under section [108(a)]'' can be regulated as a HAP. The commenter states that the EPA argues that to interpret the phrase ''air pollutant[s] listed under section [108(a)]'' as being exclusive of precursors would render meaningless the exception in CAA section 112(b)(2) for precursors. The commenter contends that it may be true in the context of CAA section 112, but it does not follow that the same interpretation applies in CAA section 111, which lacks such an express statutory exception.

Response: This commenter misunderstands the relevance of the text in CAA section 112(b)(2) in determining whether VOC are excluded from CAA section 111(d) regulation by the CAA section 108(a) exclusion. The EPA is not drawing an analogy to the outcome in CAA section 112(b)(2), which expressly removes precursors from the prohibition on the regulation under CAA section 112 of air pollutants listed under CAA section 108(a). The point here is that CAA section 112(b)(2) demonstrates that Congress understood that the phrase ''air pollutant listed under section 7408(a)'' could be read to encompass precursors. Moreover, in CAA section 112(b)(2) Congress included express language stating its choice: That regulation of precursors under CAA section 112 was not barred by the prohibition on regulating pollutants listed under CAA section 108(a). In CAA section 111(d), however, Congress did not state a choice; it stated an exclusion for pollutants listed under CAA section 108(a) without specifying whether that exclusion extended to precursors. This ambiguity, combined with the CAA section 302(g) definition of ''air pollutant'' that expressly gives the EPA the discretion to determine whether precursors are to be considered part of ''air pollutant'' on a case-by-case basis for each ''particular purpose for which the term 'air pollutant' is used,'' means that the EPA has to apply its expertise in administering the CAA program to determine whether the air pollutants excluded from CAA section 111(d) regulation by the CAA section 108(a) exclusion covers precursors. For all of the reasons discussed, the EPA has reasonably concluded that precursors are excluded by the CAA section 108(a) exclusion.

Comment: The proposal preamble for this action stated that ''CAA section 111(d) is properly understood as a 'gap-filling' measure to address pollutants that are not addressed under either the NAAQS/SIP provisions in CAA sections 108–110 or the HAP provisions in CAA section 112. Because VOC are regulated as precursors to ozone and $PM_{2.5}$ under CAA sections 108–110, they are properly excluded from regulation under CAA section 111(d) because the ''gap-filling'' function of CAA section 111(d) is not needed.'' 84 FR 50272. Some commenters agreed with the EPA's interpretation that CAA ''section 111(d) is properly understood as a 'gap filling' measure to address pollutants that are not addressed under either the NAAQS [SIP] provisions in CAA sections 108–110 or the [HAP] provisions in CAA section 112.'' These commenters generally note that regulation of existing sources under CAA section 111(d) is very rare and that the provision has been used only a handful of times, in part because it can only be triggered by a handful of pollutants and that Congress' inclusion of CAA section 111(d) can only be viewed as a safety valve for a limited number of circumstances. One commenter concludes that because VOC emissions are regulated under CAA section 108 and related statutory provisions as part of the NAAQS implementation program, they do not fall into this ''gap'' and cannot be regulated under CAA section 111(d).

Conversely, other commenters assert that the EPA's proposal preamble discussion regarding CAA section 111(d) as a gap-filling measure does not support the EPA's claim that Congress intentionally chose to exclude criteria pollutant precursors from regulation under CAA section 111(d) and that the ramifications of such an interpretation would be enormous.

The commenter states that the EPA makes a structural argument that excluding VOC from regulation under CAA section 111(d) makes sense with respect to that section's ''gap-filling'' role, since VOC are already ''regulated as pre-cursors under CAA sections 108–110'' and, thus, there is no gap to be filled. However, the commenter believes that this argument ignores the legislative history of CAA section 111(d). The commenter asserts that CAA section 111(d) began as a Senate proposal with an explicit list of pollutants to be regulated, and that ultimately, this explicit list was replaced with gradually broader phrasing until the language we see today was included in the 1970 CAA Amendments. The commenter adds that the legislative history reflects Congress' intent to give the EPA the flexibility to regulate a broad range of pollutants, rather than to constrain the EPA's discretion to a designated list of pollutants subject to regulation under CAA section 111(d). The commenter contends that the EPA's current interpretation would restrict the applicability of CAA section 111(d) to a narrower set of pollutants than Congress intended, and indeed, to a narrower set of pollutants than the Agency itself has regulated in the past. The commenter concludes that contrary to the EPA's assertions in its proposal, such a narrow interpretation upends the very idea of a ''gap-filling'' provision intended to give the Agency the flexibility to regulate a broad range of pollutants where necessary to fill gaps left by the NAAQS and NESHAP programs.

Response: The EPA disagrees with this comment. First, the argument that legislative history shows that Congress intended to give the EPA the authority to regulate a broad range of pollutants under CAA section 111(d) fails in the face of the statutory exclusions of pollutants that Congress enacted. The exclusions in CAA section 111(d) expressly narrowed the breadth of the pollutants that the EPA can regulate under CAA section 111(d). Second, the gap-filling role of CAA section 111(d) is properly understood to fill the gaps that exist *between* the regulatory regimes that address criteria/CAA section 108(a) pollutants and HAP—that is, the regulation of those pollutants that are not listed and regulated under those other CAA programs. CAA section 111(d) is not properly read to fill gaps that exist *within* those other CAA programs.

B. Impact of Lack of Regulation of Existing Oil and Natural Gas Sources Under CAA Section 111(d)

In the proposal preamble, the EPA stated that ''the lack of regulation of existing sources under CAA section 111(d) will not mean a substantial amount of lost emission reductions.'' 84 FR 50271. The proposal preamble provided several reasons for why there could be limited impact from not regulating existing oil and natural gas sources under CAA section 111(d), including (1) equipment turnover/source modifications will result in existing sources being subject to the NSPS, (2) market incentives capture valuable methane product, (3) voluntary actions to reduce methane emissions are prevalent, and (4) state regulations result in emission reductions. The EPA received comments that both agree and disagree with the EPA's conclusions and reasoning presented in the proposal preamble. These comments and the EPA response to their comments are provided below.

Comment: Several commenters assert that the EPA's assertion that the lack of regulation of existing sources directly caused by the proposed rule to deregulate methane emissions from new sources will have ''limited impact,'' does not have sufficient supporting data or analysis, and is false and arbitrary and capricious. One commenter states that, although the EPA attempts to downplay the likely impact from its non-regulation of existing sources, the EPA fails either to define what it means by ''substantial'' or to provide evidence to support this claim.

The commenters state that it would not be rational or legal for the EPA to put blinders on in order to ignore the enormous consequences of rescinding methane regulation for existing sources. The commenters assert that section 111 of the CAA is concerned with reducing dangerous pollution from stationary sources—new, modified, and existing. *See, e.g.,* 42 U.S.C. 7411(b)(1)(B) (discussing ''new sources within such category''); *Id.* 42 U.S.C. 7411(d)(2)(B) (discussing existing sources as ''sources in the category of sources''). Some commenters state that while the EPA claims that ''[a]nalysis of potential impacts of removing the requirement to regulate existing sources under CAA section 111(d) is outside the scope . . . and would be speculative,'' the EPA's refusal to consider these impacts renders its proposal unlawful.

Response: The EPA acknowledges in the proposal preamble (84 FR 50271) that by rescinding the applicability of the methane NSPS for the sources in the Crude Oil and Natural Gas Production source category, existing sources of the same type in the source category will not be subject to regulation under CAA section 111(d). The EPA is not required under a CAA section 111(b) NSPS subpart OOOOa rulemaking, however, to consider the impacts of existing sources not being regulated under a hypothetical CAA section 111(d) rule as a result of amending a CAA section 111(b) rule. While the EPA did not prepare and include a quantitative analysis that estimates the levels at which source modification/equipment turnover, market incentives, voluntary programs, and state requirements—might limit potential emissions increases from not regulating existing sources, the EPA discusses how each of these factors currently contribute and will continue to contribute to the downward trend of total methane emissions from oil and natural gas existing sources in absence of an EG in absence of existing source CAA section 111(d) guidelines.

The EPA concedes, however, that the use of the term ''substantial'' conveys a quantitative value, and that it would have been more accurate in absence of a quantitative analysis to state that these factors all have the potential to motivate or require operators to control emissions from existing sources in absence of a CAA section 111(d) EG. Further detail regarding comments received on the potential for limiting emissions from existing sources for each of these factors, and responses to these comments are provided below.

Comment: Several commenters suggest that the EPA's claim that equipment turnover, market incentives, voluntary actions, and state regulations will mean that there will not be a substantial loss of emission reductions is inconsistent with findings the EPA itself made in prior rulemakings, including the 2016 Rule. The commenters state that the EPA has provided no rational basis for its drastic shift in position (citing *Lone Mountain Processing, Inc.* v. *Secretary of Labor,* 709 F.3d 1161, 1164 (D.C. Cir. 2013)).

Response: The EPA's notes that changes have occurred since the earlier rulemakings that affect emissions from existing oil and natural gas sources. For example, there is greater industry participation in voluntary methane emissions reduction programs/actions and more state regulations/permits limiting emissions from oil and natural gas operations than there were when the EPA developed the 2016 Rule.

Comment: Commenters contend that the EPA cannot support not establishing standards under CAA section 111(d) based on source modification/equipment turnover, market incentives, voluntary programs, or state requirements factors mitigating potential emissions increases from not regulating existing sources. The commenters note that the cited factors are precisely the ones that Congress rejected when it chose to require uniform national standards. The commenters also note that the CAA is clear: The EPA ''shall prescribe regulations'' for existing sources in listed source categories that are subject to new source requirements for air pollutants not regulated under the NAAQS or section 112. 42 U.S.C. 7411(d)(1). The commenters suggest that the EPA's reliance on source modification, market incentives, voluntary programs, and state requirements to justify the proposal exceeds the Agency's authority under the CAA (citing *Massachusetts* v. *EPA,* 549 U.S. 497, 533–535 (2007) (the EPA cannot rely on a ''laundry list of reasons not to regulate'' when there is a ''clear statutory command'' under the CAA)).

Response: The EPA recognizes that rescinding the applicability of the NSPS to methane emissions for the sources in the Crude Oil and Natural Gas Production source category that are currently covered by the NSPS will mean that existing sources of the same type in the source category will not be subject to regulation under CAA section 111(d). The reasoning for not developing a CAA section 111(d) standard is not because source modification, market incentives, voluntary programs, and state requirements will limit emissions increases that may result from not pursuing a CAA section 111(d) standard. Rather, this is a legal consequence that results from the application of the CAA section 111 requirements.

Comment: Several commenters specifically provide support for, and opposition to, the individual factors (equipment turnover/source modifications, market incentives, voluntary actions, and state regulation) cited by the EPA as mitigating emission increases as a result of not regulating existing sources.

Equipment turnover/source modifications. One of the factors that the EPA provided in the proposal for the limited impact of the lack of regulation of existing sources under CAA section 111(d) was ''that the number of existing sources may decline over time due to obsolescence or to shut down and removal actions.'' 84 FR 50273. The EPA provided analysis to support this rationale and also solicited comment regarding the rate at which this decline can be expected to occur. One commenter supported the proposal by stating that because CAA section 111 defines an ''existing source'' as one that is not a ''new source,'' the universe of existing oil and natural gas sources potentially subject to CAA section 111(d) requirements would be any affected facility for which construction commenced on or before September 18, 2015, indicating that any ''existing source'' has already been in operation for at least 4 years. The commenter contends that even if the EPA were to issue EG for methane for these sources today, the Agency's 40 CFR part 60, subpart Ba regulations implementing CAA section 111(d) (Emission Guidelines for Municipal Solid Waste Landfills) provide states with 3 years to develop and submit their state plans. The commenter notes that these state plans may provide a source with up to 24 months to comply with emission standards (or longer if the compliance schedule includes legally enforceable increments of progress), and states retain discretion under CAA section 111(d) and the regulations to further extend these compliance deadlines for an individual source based on its remaining useful life or other factors. The commenter states that by the time CAA section 111(d) emission standards would become effective, roughly 10 years will have passed since the date marking the cutoff between ''new'' and ''existing'' sources. During that time period, the commenter states, it is likely that sources constructed before this cutoff will have been plugged and abandoned or replaced with new equipment that would itself be subject to the VOC requirements of NSPS subpart OOOO (which will also reduce associated methane emissions). The commenter adds that those existing oil and natural gas sources that are not plugged and abandoned or replaced may also undergo changes that qualify as ''modifications'' under NSPS subpart OOOOa, and in that case would be treated as new sources.

Conversely, several other commenters express concern that the EPA has not supported its claim that source turnover is one reason for the limited impact of not regulating existing sources. One commenter contends that the EPA's withdrawal of the ICR, coupled with its lack of information that could support a reasoned analysis, makes its action arbitrary and capricious. One commenter notes that the average life of an oil and natural gas well is 20 to 30 years, meaning that facilities installed prior to September 2015 could still be in operation in September 2045. The commenter points out that many of the largest-emitting facilities (*e.g.,* field storage tanks) typically do not undergo modification or reconstruction during their useful life.

Another commenter asserts that the EPA's claim that the existing source inventory will turn over is undercut by the EPA's extensive list, in the 2019 Proposal preamble, of questions to stakeholders about the rate of modification practices within the sector. The commenter states that the existence of the EPA's extensive list of questions indicates that the EPA has little information on how regularly these transitions occur and cannot claim that there will be little emissions impacts until after the Agency has analyzed the information that it requests.

Some commenters assert that the EPA-cited data from the U.S. Greenhouse Gas Inventory (GHGI) (for pneumatic controllers, compressors, tank throughput, and well completions); *Drillinginfo.com* (for well completions); and NSPS subpart OOOOa compliance reports (for assessing turnover rates) do not support the EPA's turnover conclusions, and exhibit substantial limitations for assessing turnover and obsolescence rates. For example, the commenters note that the GHGI provides absolute source counts for each year, but does not include information on specific sources—meaning it is not possible to assess the number of sources that are new, the number that have ceased operation, or the number that have remained in use over a time period.

Furthermore, the commenters contend that the EPA's analysis ignores large sources of emissions, such as reciprocating compressors and all leaks downstream of well pads. The commenters address the data the EPA provided by source (*i.e.,* pneumatic controllers, compressors, storage vessels, well completions) to illustrate their point that the data are insufficient or do not support the EPA's claim that many existing sources will become ''modified'' sources in the future, while other existing sources will be replaced by new facilities or shut down.

Some commenters also assert that the compliance reports and the preliminary data submitted in response to the ICR indicate that the large majority of facilities in the oil and natural gas sector are not currently complying with the NSPS. This means, according to the commenters, that these sources are existing sources with limited turnover. One commenter adds that records of natural gas operations in New Mexico demonstrates that numerous oil and natural gas fugitive emissions sources, storage tanks, and loadout emissions sources with construction dates going back to 1970 have not been modified, reconstructed, or replaced with new equipment.

Market incentives. Many commenters generally agree with the EPA's statements in the 2019 Proposal that market incentives already provide a powerful impetus for owners and operators of sources in the oil and natural gas industry to limit their methane emissions. Commenters state that the fact that the ''pollutant'' at issue is itself a valuable commodity means that source owners and operators have economic incentives to prevent its release in order to maximize the amount of natural gas that is sold for revenue. One commenter notes that the EPA's data bear that out, demonstrating that over the past 80 years, the fraction of natural gas withdrawals lost to venting and flaring has decreased from over 20 percent to just 1 or 2 percent.

Conversely, other commenters contend that there are a number of flaws with the EPA's theory that market incentives will meaningfully address methane emissions from existing oil and natural gas sources. First, one commenter notes that these theoretical ''market incentives'' largely depend on natural gas price trajectories, and contends that the EPA fails to conduct any analysis of how operators might be anticipated to reduce their emissions in light of expected natural gas prices. In reality, the commenter states, examples abound of operators choosing to flare or vent gas, rather than capture it, under current market prices. Second, a commenter states that the EPA ignores a fundamental economic principle in its discussion of market incentives: When there is a negative externality associated with an activity (here, the emission of both climate-disrupting and conventional pollution) that is not reflected in an individual operator's costs, market incentives are typically insufficient to reduce the activity to socially optimal levels. Third, a commenter states that the emissions trends noted by the EPA do not support the proposition that market incentives are adequate to reduce methane emissions from existing sources; and in fact, the data cited by the EPA shows that emissions from the oil and natural gas industry have remained persistently high despite those incentives.

Voluntary actions. Several commenters present information regarding existing voluntary programs and methane mitigation strategies being employed to reduce methane emissions from oil and natural gas operations. These commenters present a series of voluntary programs/strategies that the industry is currently undertaking and will continue to undertake to help reduce its methane emissions.

One industry representative organization [American Petroleum Institute (API)] adds that participants in The Environmental Partnership's Leak Detection and Repair Program reported a leak occurrence rate of just 0.16 percent, and that figure comes from more than 156,000 surveys across more than 78,000 production sites and is an important signal that ongoing industry efforts to identify and fix emissions sources are working.

Several other commenters contend that voluntary measures to control methane emissions would not compensate for the removal of the Federal methane requirements. Commenters note that of the thousands of oil and natural gas sources across the U.S., only about 1 percent participate in voluntary programs to address methane emissions (citing *http://blogs.edf.org/energyexchange/2019/09/03/epas-proposal-to-rollback-methane-rules-ignores-scientific-evidence-will-lead-to-5-million-tons-of-methane-pollution/*).

Commenters note that even industry members that have participated in these voluntary programs have noted that they are not a substitute for strong, uniform regulatory requirements. In addition, some commenters state that while voluntary efforts are important for reducing emissions and understanding how production operations can become more efficient and deliver environmental benefits, they cannot replace uniform Federal methane regulations for the oil and natural gas industry.

State regulations. Some commenters agree with the EPA that there are several states—including many of the states with the most significant oil and natural gas activity levels, that are already taking actions to reduce VOC and, by extension, methane emissions. One commenter states that while not every state has adopted such regulations, the states the EPA cites in the proposal cover the vast majority of the nation's oil and natural gas production, and while not every state's regulatory program covers all of the emission sources listed in NSPS subparts OOOO and OOOOa, they do all include regulatory requirements for storage vessels and fugitive emissions at well sites, ''two of the largest emission sources within the oil and natural gas industry.'' Another commenter concludes that current regulations of VOC emissions in North Dakota and other top oil and natural gas producing states will be sufficient to reduce methane emissions from the oil and natural gas industry, and that the participation of those states in national organizations such as the Environmental Council of the States (ECOS) are generating increasingly consistent state requirements that will meaningfully reduce emissions should the proposed amendments be finalized.

Other commenters assert that emissions control requirements of state regulatory programs will not be sufficient to reduce methane emissions. Commenters note that California, Colorado, Montana, New Mexico, North Dakota, Ohio, Pennsylvania, Texas, Utah, and Wyoming—the states that the EPA includes in the Proposal's ''Comparison of State Oil and Natural Gas Regulations'' table, 84 FR 50277—take widely divergent approaches that vary significantly in stringency, and most states have no standards applicable to existing sources. In 2020, according to the commenters, state standards applicable to existing sources (certain standards in California, Colorado, Utah, Wyoming (in the Upper Green River Basin ozone non-attainment area), and Texas) will reduce only 180,000 metric tons of methane, roughly 5 percent of what CAA section 111(d) guidelines modeled on the current NSPS could achieve. Other commenters added that regulation of existing sources by the EPA under section 111(d) of the CAA is preferable to a patchwork of regulations created separately by each state Agency (or the lack of regulation in some states). One commenter explains that Federal regulation creates a consistent framework that establishes a minimum level of emission control that strengthens public confidence in the natural gas industry and ensures GHG emission reductions.

Modeling analyses of impacts of foregone regulation of existing sources. Commenters presented two competing modeling analyses estimating the potential impacts of not pursuing EGs under CAA section 111(d). One presented by API supported the EPA's statements in the 2019 Proposal that the impacts would be limited, and one presented by the Environmental Defense Fund (EDF) disputed the EPA's claim.[73] [74] The assumptions used in these analyses vary; including the assumed EG requirements, the date when emissions that could have and would be controlled under an EG, what sources/segments the EG would cover, and how they accounted for turnover rates and state regulations when projecting emissions from existing sources. Neither of these analyses provide sufficient detail by emission source by segment to do a direct comparison of their analyses. However, the most important driver of differences between the competing analyses appears to be the differing assumptions regarding the emissions sources and segments the EG would regulate and the date when emissions could have and would be controlled under an EG.

The API Analysis includes a subset of emission sources compared to the EDF Analysis. The API Analysis includes the following production sources: Storage vessels, pneumatic devices, pneumatic pumps, and fugitive emissions from non-low production wells—it does not include low production wells, reciprocating/centrifugal compressors, or fugitive emissions from gathering and boosting compressor stations based on what was covered under the 2016 *Control Techniques Guidelines for the Oil and Natural Gas Industry.*[75] The EDF Analysis assumes that the EG will extend the requirements found in the 2016 Rule to all affected existing sources, specifically: High-bleed pneumatic controllers at well sites and transmission and storage compressor stations, all continuous bleed pneumatic controllers at natural gas processing plants, fugitive emissions from gas processing plants, well sites, and compressor stations, reciprocating and centrifugal compressors at both processing plants and compressor stations, and pneumatic pumps at well sites and processing plants. The EDF Analysis estimates emissions uncontrolled from existing sources starting in 2017 that would have been controlled by an EG and API assumes that an EG would not have been implemented (and, therefore, uncontrolled emissions as a result of a lack of an EG would not apply) until 2028. In absence of any other assumptions, this difference leads to vastly different results.

According to the API Analysis, if an existing source rule were implemented in 2028, minimal methane emission reductions (5 percent − (102,000 MT (metric tons) methane) from NSPS regulated sources would be realized with their hypothetical reductions decaying to ~1 percent (24,000 MT) of the total emissions from regulated sources by 2043. The API Analysis concludes that by 2028, 94 percent (and by 2043, 99 percent) of oil and natural gas production will be regulated by 40 CFR part 60, subpart OOOO or OOOOa. In other words, the API Analysis estimates that an EG modeled after a modified version of the EPA's 2016 Control Techniques Guideline would only achieve an additional 5 percent of emissions reductions when compared to the NSPS regulations alone. The API provides that their analysis illustrates that an existing source rule would provide negligible environmental benefit.

This is in contrast to the EDF Analysis that estimates that each year that the EPA does not promulgate EG under CAA section 111(d) will allow substantial additional emissions. They estimate emissions that have occurred and will occur starting in 2017 through 2030 by the EPA's failure to adopt EGs, as well as the emission reductions possible if EGs were promulgated. For example, they estimate that, in 2021, 9.8

[73] Earth Systems Sciences, LLC (for API). Methane Emissions from Regulated Onshore Production Sources. Evaluating the Impact of Existing Federal and State Regulations. October 2019. (Docket ID Item No. EPA–HQ–OAR–2017–0757–2090, Appendix A) (API Analysis).

[74] EDF. Assessment of Harm to the Public from Foregoing Methane Guidelines for Existing Sources. November 21, 2019. (Docket ID Item No. EPA–HQ–OAR–2017–0757–2134; Appendix D) (EDF Analysis).

[75] U.S. EPA. Control Techniques Guidelines for the Oil and Natural Gas Industry. October 2016. EPA–453–/B–16–001). *https://www.epa.gov/sites/production/files/2016-10/documents/2016-ctg-oil-and-gas.pdf.*

million metric tons of methane will be emitted by affected existing sources. The EDF Analysis estimates that by 2030, emissions from existing sources will be substantial and have a cumulative impact of about 126 MMT of methane; about 29 MMT of VOC; and about 1.1 million tons of HAP. The EDF Analysis estimates that in the over 3 years since the EPA has promulgated the 2016 Rule, 33.4 MMT of methane have been emitted by existing oil and natural gas sources. They further estimate that 12.2 MMT of those methane emissions, or 37 percent, could have been avoided if EGs were in effect.

Response: The EPA's response to comments specific to the four factors cited by the EPA in the proposal preamble for why there would be limited impacts from not regulating existing oil and natural gas sources under CAA section 111(d), are provided in the following paragraphs. *Equipment turnover/source modifications.* For the first factor (equipment turnover/source modifications will result in existing sources being subject to the NSPS), the EPA reviewed information and analyses supporting the proposal's claim of a high turnover rate (limited impact of an EG) and information/analyses that supporting a low turnover rate (substantial impact of an EG).

Referring to the API and EDF Analyses, each of those analyses accounted for turnover and source modifications differently in their emissions projections in absence of an EG under CAA section 111(d). The approaches used and information provided in these analyses do not allow for a direct comparison on how their differing assumptions impact their results. The API Analysis does not include modification triggers in their projection modeling, contending that the lack of modification triggers in their model is a conservative assumption because it will underestimate the number of wells that are covered by NSPS requirements in the future. However, the API Analysis used historical well records to estimate a distribution for the expected lifetime of wells (and associated equipment) in each state. The EDF Analysis assumes that emissions attributable to existing sources decline year-over-year as existing sources are removed from operation or undertake modifications that subject them to regulation as modified sources under the 2016 Rule based on turnover rate percentages. Insufficient detail provided by EDF on where the turnover percentage rates they used in their analysis came from. It is unclear how the percentages used (existing source decline turnover rate of 5 percent for production sources, 4 percent for gathering and boosting sources, and 1 percent for all downstream sources) in the EDF Analysis were estimated.

The EPA recognizes the limitations pointed out by commenters regarding the GHGI (for pneumatic controllers, compressors, tank throughput, and well completions); *Drillinginfo.com* (for well completions); and NSPS subpart OOOOa compliance reports (for assessing turnover rates). As commenters indicate, when comparing activity counts, compliance reports, and preliminary information received in the ICR process, the data indicates that there is incomplete information to assess turnover and obsolescence rates. The justification of the EPA's rescission of the ICR is presented in a separate rulemaking action, ''Notice Regarding Withdrawal of Obligation To Submit Information'' (82 FR 12817, March 7, 2017). Absent further information (which is why we solicited comment on turnover rates) and time, where compliance report information can be assessed over a longer time period, there will continue to be a high level of uncertainty with any estimates on turnover/obsolescence rates.

The EPA maintains, however, as it did in the proposal, that equipment turnover and source modification are a factor (albeit difficult to quantify with any certainty) that will limit the emissions from existing sources in the oil and natural gas industry in the absence of a CAA section 111(d) EG. In addition to the reasons stated in the proposal, we acknowledge that it could take up to 7 to 10 years from date of promulgation of an EG for requirements to be fully implemented. During this time, the EPA expects that a percentage of existing sources will shut down or undertake modification, which will result in them becoming subject to regulation under CAA section 111(b). This turnover, in the case of well-sites, would likely be impacted as production declines and dependent on the economic viability of the well-site.

Lastly, the EPA acknowledges the information the state of New Mexico identifies that indicates that there are existing sources in that state that have never been modified as supporting that turnover and modifications will not be a factor that results in reducing emissions from oil and natural gas existing sources in that area in absence of an EG and accepts that these are examples of existing sources that have continued to operate for long periods of time without being reconstructed or modified.

Market incentives. With regards to the second factor (market incentives), as stated in section VII.B of this preamble, there are market incentives for the oil and natural gas industry to capture as much natural gas (and, by extension, methane) as is cost effective. Depending on the future trajectories of natural gas prices and the costs of natural gas capture and emission reductions, market incentives may continue to drive emission reductions, even in the absence of specific regulatory requirements applicable to methane emissions from existing sources. While it is a challenging concept to quantify in monetary terms, improving their environmental performance is increasingly important for firms to maintain a ''social license to operate.'' Generally speaking, the social license to operate means that the firm's employees, investors, customers, and the general public find that the firm's business activities and operations are acceptable to continue to freely participate in the marketplace. Maintaining the social license by improving environmental performance, such as reducing emissions, can help firms respond to the complex environment within which they operate in ways that are favorable to their longer-term business interests.

In response to the commenter that states that the emissions trends noted by the EPA do not support the proposition that market incentives are adequate to reduce methane emissions from existing sources in lieu of Federal regulation, the EPA is not making that claim. The EPA claims that market incentives are one factor (among others) that contribute and will continue to contribute to the downward trend of total methane emissions from oil and natural gas existing sources in absence of an EG.

Voluntary action. With regards to the third factor (voluntary actions), the EPA maintains, and has received a lot of comments in support of, its position that the plethora of voluntary methane emissions mitigation programs will limit (among other factors) methane emissions increases from existing oil and natural gas industry emission sources in absence of a CAA section 111(d) EG. The EPA does acknowledge, however, as several commenters contend, that the industry as a whole is not uniformly meeting voluntary measures at the same level of control and that some companies may not be participating in cited voluntary methane emissions programs at all. This makes it difficult to verify the impacts on emissions as a result of voluntary program participation. Additional time will be needed to allow these programs to further develop and to be fully implemented to better quantify the impacts the varied programs have on limiting emissions from oil and natural gas industry sources.

In response to the commenters that contend that voluntary actions cannot be relied upon to reduce methane emissions from existing sources in lieu of Federal regulation, the EPA is not making that claim. As with other mitigating factors cited by the EPA, voluntary actions are one factor (among others) that contribute and will continue to contribute to the downward trend of total methane emissions from oil and natural gas existing sources in absence of an EG.

State regulations. With regards to the fourth and final factor (state regulations), the EPA agrees that there could be an impact of not regulating existing oil and natural gas sources, but at this time, the EPA has not conducted a quantitative analysis of the impact of state regulatory programs to determine the degree to which those programs would reduce emissions from existing sources. The EPA also acknowledges that state requirements do vary in stringency and that only a subset of states include requirements for sources that the EPA could potentially define as existing sources. However, those states that have standards applicable to existing sources (certain standards in California, Colorado, Utah, Wyoming (in the Upper Green River Basin ozone non-attainment area), and Texas) account for a substantial portion of oil and natural gas production in the United States. The EPA also expects a percentage of existing sources to shut down or undertake modification which would make them become subject to certain state standards or permits. As one of the commenters points out, and the EPA agrees, while not every state has adopted specific methane emissions regulations for oil and natural gas industry existing sources, current regulations (and permits) controlling VOC emissions in North Dakota and other top oil and natural gas producing states will concurrently reduce methane emissions from the oil and natural gas industry.

In response to the commenters that contend that state regulations/permits that include oil and natural gas industry existing source emissions control requirements cannot be relied upon to reduce methane emissions from existing sources in lieu of Federal regulation, the EPA is not making that claim. As with other mitigating factors cited by the EPA, existing source state requirements are one factor (among others) that contribute and will continue to contribute to the downward trend of total methane emissions from oil and natural gas existing sources in absence of an EG.

XI. Impacts of This Final Rule

A. What are the air impacts?

The EPA projected that, from 2021 to 2030, relative to the baseline, the final rule will forgo about 448,000 short tons of methane emissions reductions (10.1 million tons CO_2 Eq.), 12,000 short tons of VOC emissions reductions, and 400 short tons of HAP emission reductions from facilities affected by this reconsideration.[76] The EPA estimated regulatory impacts beginning in 2021 as it is the first full year of implementation of this rule. The EPA estimated impacts through 2030 to illustrate the accumulating effects of this rule over a longer period. The EPA did not estimate impacts after 2030 for reasons including limited information, as explained in the RIA.

B. What are the energy impacts?

Energy impacts in this section are those energy requirements associated with the operation of emissions control devices. Potential impacts on the national energy economy from the rule are discussed in the economic impacts section. Under the final rule, there will likely be little change in the national energy demand resulting from the deregulatory actions finalized here.

C. What are the compliance costs?

The PV of the regulatory compliance cost reduction associated with this final rule over the 2021 to 2030 period was estimated to be $67 million (in 2016 dollars) using a 7-percent discount rate and $83 million using a 3-percent discount rate. The EAV of these cost reductions is estimated to be $8.9 million per year using a 7-percent discount rate and $9.4 million per year using a 3-percent discount rate.

These estimates do not, however, include the forgone producer revenues associated with the decrease in the recovery of saleable natural gas, though some of the compliance actions required in the baseline would likely have captured saleable product that would have otherwise been emitted to the atmosphere. Estimates of the value of the recovered product were included in previous regulatory analyses as offsetting compliance costs. Because of the deregulatory nature of this final action, the EPA projected a reduction in the recovery of saleable product. Using the 2020 Annual Energy Outlook (AEO) projection of natural gas prices to estimate the value of the change in the recovered gas at the wellhead projected to result from the final action, the EPA estimated a PV of regulatory compliance cost reductions of the final rule over the 2021 to 2030 period of $31 million using a 7-percent discount rate and $38 million using a 3-percent discount rate. The corresponding estimates of the EAV of cost reductions after accounting for the forgone revenues were $4.1 million per year using a 7-percent discount rate and $4.3 million per year using a 3-percent discount rate.

D. What are the economic and employment impacts?

The EPA used the National Energy Modeling System (NEMS) to estimate the impacts of the 2016 Rule on the U.S. energy system. The NEMS is a publicly available model of the U.S. energy economy developed and maintained by the EIA and is used to produce the AEO, a reference publication that provides detailed projections of the U.S. energy economy.[77] The EPA estimated small impacts on crude oil and natural gas markets of the 2016 Rule over the 2020 to 2025 period. This final rule will result in a decrease in total compliance costs relative to the baseline. Therefore, the EPA expects that this rule will partially reduce the impacts estimated for the 2016 Rule in the 2016 Rule RIA.

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). While a standalone analysis of employment impacts is not included in a standard benefit-cost analysis, such an analysis is of concern in the current economic climate given continued interest in the employment impact of regulations such as this proposed rule. The EPA estimated the change in compliance-related labor due to the reduced requirements for the installation, operation, and maintenance of control equipment, control activities, and labor associated with reporting and recordkeeping requirements in the 2016

[76] In a separate action, the EPA is finalizing technical reconsideration amendments to 40 CFR part 60, subpart OOOOa (EPA–HQ–OAR–2017–0483; FRL–10013–60–OAR; FR Doc. 2020–18115). These technical amendments were proposed in October 2018. 83 FR 52056. Please reference that final rule for the summary and rationale of those technical changes. Please refer to the RIA for both rules to see the combined impacts.

[77] *https://www.eia.gov/outlooks/aeo/.*

Rule RIA. Under the final rule, the EPA expects there will be slight reductions in the labor required for compliance-related activities associated with the 2016 Rule requirements relating to the rescission of requirements in the transmission and storage segment of the oil and natural gas industry.

E. What are the benefits of the final standards?

The EPA expects forgone climate and health benefits due to the forgone emissions reductions projected under this final rule. The EPA estimated the forgone domestic climate benefits from the forgone methane emissions reductions using an interim measure of the domestic social cost of methane (SC-CH_4). The SC-CH_4 estimates used here were developed under Executive Order 13783 for use in regulatory analyses until an improved estimate of the impacts of climate change to the U.S. can be developed based on the best available science and economics. Executive Order 13783 directed agencies to ensure that estimates of the social cost of GHG used in regulatory analyses ''are based on the best available science and economics'' and are consistent with the guidance contained in OMB Circular A–4, ''including with respect to the consideration of domestic versus international impacts and the consideration of appropriate discount rates'' (Executive Order 13783, Section 5(c)). In addition, Executive Order 13783 withdrew the technical support documents (TSDs) and the August 2016 Addendum to these TSDs describing the global social cost of GHG estimates developed under the prior Administration as no longer representative of government policy. The withdrawn TSDs and Addendum were developed by an interagency working group that included the EPA and other executive branch entities and were used in the 2016 Rule RIA.

The EPA estimated the PV of the forgone domestic climate benefits over the 2021 to 2030 period to be $17 million under a 7-percent discount rate and $63 million under a 3-percent discount rate. The EAV of these forgone benefits is estimated $2.2 million per year under a 7-percent discount rate and $7.2 million per year under a 3-percent discount rate. These values represent only a partial accounting of domestic climate impacts from methane emissions and do not account for health effects of ozone exposure from the increase in methane emissions.

Under the final rule, the EPA expects that forgone VOC emission reductions will degrade air quality and are likely to adversely affect health and welfare associated with exposure to ozone, $PM_{2.5}$, and HAP, but did not quantify these effects at this time. This omission should not imply that these forgone benefits may not exist; rather, it reflects the inherent difficulties in accurately modeling the direct and indirect impacts of the projected reductions in emissions for this industrial sector. To the extent that the EPA were to quantify these ozone and PM impacts, it would estimate the number and value of avoided premature deaths and illnesses using an approach detailed in the Particulate Matter NAAQS and Ozone NAAQS Regulatory Impact Analyses.[78 79] This approach relies on full-form air quality modeling. The Agency is committed to assessing ways of conducting full-form air quality modeling for the oil and natural gas sector that would be suitable for use in regulatory analysis in the context of NSPS, including ways to address the uncertainties regarding the scope and magnitude of VOC emissions.

When quantifying the incidence and economic value of the human health impacts of air quality changes, the Agency sometimes relies upon alternative approaches to using full-form air quality modeling, called reduced-form techniques, often reported as ''benefit-per-ton'' values that relate air pollution impacts to changes in air pollutant precursor emissions.[80] A small, but growing, literature characterizes the air quality and health impacts from the oil and natural gas sector.[81 82 83] The Agency feels more work needs to be done to vet the analysis and methodologies for all potential approaches for valuing the health effects of VOC emissions before they are used in regulatory analysis, but is committed to continuing this work. Recently, the EPA systematically compared the changes in benefits, and concentrations where available, from its benefit-per-ton technique and other reduced-form techniques against the changes in benefits and concentrations derived from full-form photochemical model representation of a few different specific emissions scenarios.[84] The Agency's goal was to create a methodology by which investigators could better understand the suitability of alternative reduced-form air quality modeling techniques for estimating the health impacts of criteria pollutant emissions changes in the EPA's benefit-cost analysis, including the extent to which reduced form models may over- or under-estimate benefits (compared to full-scale modeling) under different scenarios and air quality concentrations. The EPA Science Advisory Board (SAB) recently convened a panel to review this report.[85] In particular, the SAB will assess the techniques the Agency used to appraise these tools; the Agency's approach for depicting the results of reduced-form tools; and, steps the Agency might take for improving the reliability of reduced-form techniques for use in future Regulatory Impact Analyses RIAs. The scenario-specific emission inputs developed for this project are currently available online.[86] A thorough description of the study design and methodology is also available.[87]

XII. Statutory and Executive Order Reviews

Additional information about these statutes and Executive orders can be found at *https://www.epa.gov/laws-regulations/laws-and-executive-orders*.

[78] U.S. EPA. December 2012. Regulatory Impact Analysis for the Final Revisions to the National Ambient Air Quality Standards for Particulate Matter. EPA–452/R–12–005. Office of Air Quality Planning and Standards, Health and Environmental Impacts Division. *https://www3.epa.gov/ttnecas1/regdata/RIAs/finalria.pdf.* Accessed January 9, 2020.

[79] U.S. EPA. September 2015. Regulatory Impact Analysis of the Final Revisions to the National Ambient Air Quality Standards for Ground-Level Ozone. EPA–452/R–15–007. Office of Air Quality Planning and Standards, Health and Environmental Impacts Division. *https://www3.epa.gov/ttnecas1/docs/20151001ria.pdf.* Accessed January 9, 2020.

[80] U.S. EPA. February 2018. Technical Support Document: Estimating the Benefit per Ton of Reducing $PM_{2.5}$ Precursors from 17 Sectors. *https://www.epa.gov/sites/production/files/2018-02/documents/sourceapportionmentbpttsd_2018.pdf.* Accessed January 9, 2020.

[81] Fann, N., K.R. Baker, E.A.W. Chan, A. Eyth, A. Macpherson, E. Miller, and J. Snyder. 2018. ''Assessing Human Health $PM_{2.5}$ and Ozone Impacts from U.S. Oil and Natural Gas Sector Emissions in 2025.'' Environmental Science and Technology 52(15):8095–8103.

[82] Litovitz, A., A. Curtright, S. Abramzon, N. Burger, and C. Samaras. 2013. ''Estimation of Regional Air-Quality Damages from Marcellus Shale Natural Gas Extraction in Pennsylvania.'' Environmental Research Letters 8(1), 014017.

[83] Loomis, J. and M. Haefele. 2017. ''Quantifying Market and Non-market Benefits and Costs of Hydraulic Fracturing in the United States: A Summary of the Literature.'' Ecological Economics 138:160–167.

[84] This analysis compared the benefits estimated using full-form photochemical air quality modeling simulations (CMAQ and CAMx) against four reduced-form tools, including: InMAP; AP2/3; EASIUR; and EPA's benefit-per-ton.

[85] 85 FR 23823 (April 29, 2020).

[86] The scenario-specific emission inputs developed for this project and all associated documentation are currently available online at *https://github.com/epa-kpc/RFMEVAL.*

[87] Baker, K.R., M. Amend, S. Penn, J. Bankert, H. Simon, E. Chan, N. Fann, M. Zawacki, K. Davidson, K. and H. Roman. 2020. ''A Database for Evaluating the InMAP, APEEP, and EASIUR Reduced Complexity Air-Quality Modeling Tools.'' Data in Brief 28: 104886.

A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review

This action is a significant regulatory action that was submitted to the Office of Management and Budget (OMB) for review because it raises novel legal or policy issues. Any changes made in response to OMB recommendations have been documented in the docket. In addition, the EPA prepared an RIA of the potential costs and benefits associated with this final action. The RIA available in the docket describes in detail the empirical basis for the EPA's assumptions and characterizes the various sources of uncertainties affecting the estimates below. Table 8 shows the PV and EAV of the costs, benefits, and net benefits of the final rule for the 2021 to 2030 period relative to the baseline using discount rates of 7 and 3 percent, respectively. The table also shows the total forgone emission reductions projected from 2021 to 2030 relative to the baseline.

In the following table, we refer to the compliance cost reductions as the ''benefits'' and the forgone benefits as the ''costs'' of this final action. The net benefits are the benefits (total cost reductions) minus the costs (forgone domestic climate benefits).

TABLE 8—SUMMARY OF THE PV AND EAV OF THE MONETIZED FORGONE BENEFITS, COST REDUCTIONS, AND NET BENEFITS FROM 2021 TO 2030, 7- AND 3-PERCENT DISCOUNT RATES

[Millions of 2016$]

	7-Percent discount rate		3-Percent discount rate	
	PV	EAV	PV	EAV
Benefits (Total Cost Reductions)	$31	$4.1	$38	$4.3
Compliance Cost Reductions	*67*	*8.9*	*83*	*9.4*
Forgone Value of Product Recovery	*36*	*4.7*	*45*	*5.1*
Costs (Forgone Domestic Climate Benefits)	17	2.2	63	7.2
Net Benefits	14	1.9	−25	−2.9
Non-Monetized Forgone Benefits	Non-monetized climate impacts from increases in methane emissions. Health effects of $PM_{2.5}$ and ozone exposure from an increase of about 11,000 short tons of VOC from 2021 through 2030. Health effects of HAP exposure from an increase of about 330 short tons of HAP from 2021 through 2030. Health effects of ozone exposure from an increase of about 400,000 short tons of methane from 2021 through 2030. Visibility impairment. Vegetation effects.			

Note: Estimates may not sum due to independent rounding.

B. Executive Order 13771: Reducing Regulations and Controlling Regulatory Costs

This action is considered an Executive Order 13771 deregulatory action. Details on the estimated cost savings of this final rule can be found in the EPA's analysis of the potential costs and benefits associated with this action.

C. Paperwork Reduction Act (PRA)

The information collection activities in this final rule have been submitted for approval to OMB under the PRA. The ICR document that the EPA prepared has been assigned EPA ICR number 2604.02 and OMB Control Number 2060–0729. The information collection requirements are not enforceable until OMB approves them.

A summary of the information collection activities previously submitted to the OMB for the final action titled ''Standards of Performance for Crude Oil and Natural Gas Facilities for Construction, Modification, or Reconstruction'' (2016 Rule) under the PRA, and assigned OMB Control Number 2060–0721 (EPA ICR number 2523.02), can be found at 81 FR 35890. You can find a copy of the ICR in the 2016 Rule Docket (Docket ID Item No. EPA–HQ–OAR–2010–0505–7626). In this rule, the EPA is finalizing the information collection activities as a result of the EPA's review under Executive Order 13783 (EPA ICR number 2604.02). These final changes (2020 NSPS Subpart OOOOa Executive Order 13783 Review Final) would remove reporting and recordkeeping requirements associated with the rescinded requirements.[88]

Comments were received on the October 15, 2018 (83 FR 52056) proposed rule indicating that the recordkeeping and reporting burden for the 2016 Rule was significantly underestimated. In particular, the commenters pointed to the estimated burden associated with the fugitive emissions requirements. As a result of these comments, the EPA reexamined the analysis for the 2016 Rule recordkeeping and reporting burden and made adjustments where warranted. This resulted in an updated and more accurate assessment of the recordkeeping and reporting burden for the 2016 Rule. The updated 2016 Rule recordkeeping and reporting burden was estimated at a 3-year annual average of 689,154 hours and $110,336,343 (2016$) over the 3-year period. These figures represent the ''baseline'' from which changes made in these final amendments (2020 NSPS Subpart OOOOa Executive Order 13783 Review Final) can be compared. Burden associated with this rule (2020 Rule E.O. 13783 Review Final):

Respondents/affected entities: Oil and natural gas operators and owners.

Respondent's obligation to respond: Mandatory.

Estimated number of respondents: 519.

[88] In a separate action, the EPA is finalizing technical reconsideration amendments to NSPS subpart OOOOa (EPA–HQ–OAR–2017–0483; FRL–10013–60–OAR; FR Doc. 2020–18115). These technical amendments where proposed in October 2018. 83 FR 52056. The information collection burden for the combination of these NSPS subpart OOOOa Reconsideration final amendments and the Policy Review final amendments is addressed in a separate ICR (OMB Control Number 2060–0721; EPA ICR number 2523.04).

Frequency of response: Varies depending on affected facility.[89]

Total estimated burden: 680,841 hours (per year). Burden is defined at 5 CFR 1320.3(b).

Total estimated cost: $108,723,359 (2016$), which includes no capital or O&M costs.

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.

D. Regulatory Flexibility Act (RFA)

I certify that this action will not have a significant economic impact on a substantial number of small entities under the RFA. In making this determination, the impact of concern is any significant adverse economic impact on small entities. An agency may certify that a rule will not have a significant economic impact on a substantial number of small entities if the rule relieves regulatory burden, has no net burden, or otherwise has a positive economic effect on the small entities subject to the rule. This is a deregulatory action, and the burden on all entities affected by this final rule, including small entities, is the same or reduced compared to the 2016 Rule. *See* the discussion in section XI of this preamble and the RIA for details. The EPA has, therefore, concluded that this action will have no net increase regulatory burden for all directly regulated small entities.

E. Unfunded Mandates Reform Act (UMRA)

This action does not contain any unfunded mandate as described in UMRA, 2 U.S.C. 1531–1538, and does not significantly or uniquely affect small governments. The action imposes no enforceable duty on any state, local, or tribal governments or the private sector.

F. Executive Order 13132: Federalism

This action does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the National Government and the states, or on the distribution of power and responsibilities among the various levels of government.

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

This action does not have tribal implications as specified in Executive Order 13175. It will not have substantial direct effects on tribal governments, on the relationship between the Federal Government and Indian tribes, or on the distribution of power and responsibilities between the Federal Government and Indian tribes, as specified in Executive Order 13175. Thus, Executive Order 13175 does not apply to this action.

Consistent with the EPA Policy on Consultation and Coordination with Indian Tribes, on September 10, 2019, the EPA sent a letter to all tribal governments inviting consultation. Additionally, on August 29, 2019, and September 18, 2019, the EPA provided an overview of the proposed rule to the National Tribal Air Association. The EPA did not receive any requests for consultation.

H. 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. The 2016 Rule, as discussed in the RIA,[90] was anticipated to reduce emissions of methane, VOC, and HAP, and some of the benefits of reducing these pollutants would have accrued to children. The final rule is expected to decrease the impact of the emissions reductions estimated from the 2016 Rule on these benefits, as discussed in the RIA.

The final action does not affect the level of public health and environmental protection already being provided by existing NAAQS and other mechanisms in the CAA. This final action does not affect applicable local, state, or Federal permitting or air quality management programs that will continue to address areas with degraded air quality and maintain the air quality in areas meeting current standards. Areas that need to reduce criteria air pollution to meet the NAAQS will still need to rely on control strategies to reduce emissions. The EPA does not believe the decrease in emission reductions projected by the final rule will have a disproportionate adverse effect on children's health.

I. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

This 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. In the RIA accompanying the 2016 Rule, the EPA used the NEMS to estimate the impacts of the 2016 Rule on the United States energy system. The EPA estimated small impacts of that rule over the 2020 to 2025 period relative to the baseline for that rule. This final rule is estimated to result in a decrease in total compliance costs, with the reduction in costs affecting a subset of the affected entities under NSPS subpart OOOOa. Therefore, the EPA expects that this deregulatory action will reduce the impacts estimated for the final NSPS in the 2016 RIA and, as such, is not a significant energy action.

J. National Technology Transfer and Advancement Act (NTTAA)

This rulemaking does not involve technical standards.

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

The EPA believes that this final action is unlikely to have disproportionately high and adverse human health or environmental effects on minority populations, low-income populations, and/or indigenous peoples, as specified in Executive Order 12898 (59 FR 7629, February 16, 1994). The 2016 Rule was anticipated to reduce emissions of methane, VOC, and HAP, and some of the benefits of reducing these pollutants would have accrued to minority populations, low-income populations, and/or indigenous peoples. The final rule is expected to decrease the impact of the emission reductions estimated from the 2016 Rule on these benefits. These communities may experience forgone benefits as a result of this action, as discussed in the RIA.

This final action does not affect the level of public health and environmental protection already being provided by existing NAAQS and other mechanisms in the CAA. This final action does not affect applicable local, state, or Federal permitting or air quality management programs that will continue to address areas with degraded air quality and maintain the air quality in areas meeting current standards. Areas that need to reduce criteria air pollution to meet the NAAQS will still

[89] The specific frequency for each information collection activity within this request is shown in Tables 1a through 1d of the Supporting Statement in the public docket.

[90] *See* Final RIA in the public docket for this rulemaking.

need to rely on control strategies to reduce emissions.

The EPA believes that this final action is unlikely to have disproportionately high and adverse human health or environmental effects on minority populations, low-income populations, and/or indigenous peoples. The EPA notes that the potential impacts of the final rule are not expected to be experienced uniformly, and the distribution of avoided compliance costs associated with this action depends on the degree to which costs would have been passed through to consumers.

L. Congressional Review Act (CRA)

This action is subject to the CRA, and the EPA will submit a rule report to each House of the Congress and to the Comptroller General of the United States. This action is not a ''major rule'' as defined by 5 U.S.C. 804(2).

List of Subjects in 40 CFR Part 60

Environmental protection, Administrative practice and procedure, Air pollution control, Reporting and recordkeeping requirements.

Andrew Wheeler,

Administrator.

For the reasons set forth in the preamble, the EPA amends 40 CFR part 60 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. Revise the heading of subpart OOOO to read as follows:

Subpart OOOO—Standards of Performance for Crude Oil and Natural Gas Facilities for Which Construction, Modification, or Reconstruction Commenced After August 23, 2011, and on or Before September 18, 2015

■ 3. Section 60.5360 is amended to read as follows:

§ 60.5360 What is the purpose of this subpart?

This subpart establishes emission standards and compliance schedules for the control of volatile organic compounds (VOC) and sulfur dioxide (SO_2) emissions from affected facilities in the crude oil and natural gas production source category that commence construction, modification, or reconstruction after August 23, 2011, and on or before September 18, 2015.

■ 4. Section 60.5365 is amended by revising the introductory text and paragraphs (b), (c), and (d)(1), removing and reserving paragraph (d)(2), and revising paragraph (e) introductory text to read as follows:

§ 60.5365 Am I subject to this subpart?

You are subject to the applicable provisions of this subpart if you are the owner or operator of one or more of the onshore affected facilities listed in paragraphs (a) through (g) of this section that is located within the Crude Oil and Natural Gas Production source category, as defined in § 60.5430 for which you commence construction, modification, or reconstruction after August 23, 2011, and on or before September 18, 2015.

* * * * *

(b) Each centrifugal compressor affected facility, which is a single centrifugal compressor using wet seals. A centrifugal compressor located at a well site, or an adjacent well site and servicing more than one well site, is not an affected facility under this subpart.

(c) Each reciprocating compressor affected facility, which is a single reciprocating compressor. A reciprocating compressor located at a well site, or an adjacent well site and servicing more than one well site, is not an affected facility under this subpart.

(d)(1) For the oil and natural gas production segment, each pneumatic controller affected facility, which is a single continuous bleed natural gas-driven pneumatic controller operating at a natural gas bleed rate greater than 6 standard cubic feet per hour.

* * * * *

(e) Each storage vessel affected facility, which is a single storage vessel, and has the potential for VOC emissions equal to or greater than 6 tons per year (tpy) as determined according to this section by October 15, 2013, for Group 1 storage vessels and by April 15, 2014, or 30 days after startup (whichever is later) for Group 2 storage vessels, except as provided in paragraphs (e)(1) through (4) of this section. The potential for VOC emissions must be calculated using a generally accepted model or calculation methodology, based on the maximum average daily throughput determined for a 30-day period of production prior to the applicable emission determination deadline specified in this section. The determination may take into account requirements under a legally and practically enforceable limit in an operating permit or other requirement established under a Federal, State, local or tribal authority.

* * * * *

■ 5. Section 60.5420 is amended by revising paragraph (c)(5)(iv) to read as follows:

§ 60.5420 What are my notification, reporting, and recordkeeping requirements?

* * * * *

(c) * * *

(5) * * *

(iv) For storage vessels that are skid-mounted or permanently attached to something that is mobile (such as trucks, railcars, barges, or ships), records indicating the number of consecutive days that the vessel is located at the site. If a storage vessel is removed from the site and, within 30 days, is either returned to or replaced by another storage vessel at the site to serve the same or similar function, then the entire period since the original storage vessel was first located at the site, including the days when the storage vessel was removed, will be added to the count towards the number of consecutive days.

* * * * *

■ 6. Section 60.5430 is amended by:

■ a. Adding the definition for *Crude Oil and Natural Gas Production source category* in alphabetical order.

■ b. Revising the definition of *Custody transfer.*

■ c. Adding the definitions for *Local distribution company (LDC) custody transfer station* and *Natural gas transmission and storage segment* in alphabetical order.

The additions and revision read as follows:

§ 60.5430 What definitions apply to this subpart?

* * * * *

Crude Oil and Natural Gas Production source category means:

(1) Crude oil production, which includes the well and extends to the point of custody transfer to the crude oil transmission pipeline or any other forms of transportation; and

(2) Natural gas production and processing, which includes the well and extends to, but does not include, the point of custody transfer to the natural gas transmission and storage segment.

Custody transfer means the transfer of crude oil or natural gas after processing and/or treatment in the producing operations, or from storage vessels or automatic transfer facilities or other such equipment, including product loading racks, to pipelines or any other forms of transportation.

* * * * *

Local distribution company (LDC) custody transfer station means a metering station where the LDC receives a natural gas supply from an upstream supplier, which may be an interstate transmission pipeline or a local natural gas producer, for delivery to customers through the LDC's intrastate transmission or distribution lines.

* * * * *

Natural gas transmission and storage segment means the transport or storage of natural gas prior to delivery to a ''local distribution company custody transfer station'' (as defined in this section) or to a final end user (if there is no local distribution company custody transfer station). For the purposes of this subpart, natural gas enters the natural gas transmission and storage segment after the natural gas processing plant, when present. If no natural gas processing plant is present, natural gas enters the natural gas transmission and storage segment after the point of ''custody transfer'' (as defined in this section). A compressor station that transports natural gas prior to the point of ''custody transfer'' or to a natural gas processing plant (if present) is not considered a part of the natural gas transmission and storage segment.

* * * * *

Subpart OOOOa—Standards of Performance for Crude Oil and Natural Gas Facilities for Which Construction, Modification, or Reconstruction Commenced After September 18, 2015

■ 7. Section 60.5360a is revised to read as follows:

§ 60.5360a What is the purpose of this subpart?

(a) This subpart establishes emission standards and compliance schedules for the control of volatile organic compounds (VOC) and sulfur dioxide (SO_2) emissions from affected facilities in the Crude Oil and Natural Gas Production source category that commence construction, modification, or reconstruction after September 18, 2015. The effective date of the rule in this subpart is August 2, 2016.

(b) [Reserved]

■ 8. Section 60.5365a is amended by revising the introductory text to read as follows:

§ 60.5365a Am I subject to this subpart?

You are subject to the applicable provisions of this subpart if you are the owner or operator of one or more of the onshore affected facilities listed in paragraphs (a) through (j) of this section, that is located within the Crude Oil and Natural Gas Production source category, as defined in § 60.5430a, for which you commence construction, modification, or reconstruction after September 18, 2015.

* * * * *

■ 9. Section 60.5375a is amended by revising the section heading and introductory text to read as follows:

§ 60.5375a What VOC standards apply to well affected facilities?

If you are the owner or operator of a well affected facility as described in § 60.5365a(a) that also meets the criteria for a well affected facility in § 60.5365(a) (in subpart OOOO of this part), you must reduce VOC emissions by complying with paragraphs (a) through (g) of this section. If you own or operate a well affected facility as described in § 60.5365a(a) that does not meet the criteria for a well affected facility in § 60.5365(a) (in subpart OOOO of this part), you must reduce VOC emissions by complying with paragraphs (f)(3) and (4) or paragraph (g) of this section for each well completion operation with hydraulic fracturing prior to November 30, 2016, and you must comply with paragraphs (a) through (g) of this section for each well completion operation with hydraulic fracturing on or after November 30, 2016.

* * * * *

■ 10. Section 60.5380a is amended by revising the section heading, introductory text, and paragraph (a)(1) to read as follows:

§ 60.5380a What VOC standards apply to centrifugal compressor affected facilities?

You must comply with the VOC standards in paragraphs (a) through (d) of this section for each centrifugal compressor affected facility.

(a)(1) You must reduce VOC emissions from each centrifugal compressor wet seal fluid degassing system by 95.0 percent.

* * * * *

■ 11. Section 60.5385a is amended by revising the section heading, introductory text, and paragraph (a)(3) to read as follows:

§ 60.5385a What VOC standards apply to reciprocating compressor affected facilities?

You must reduce VOC emissions by complying with the standards in paragraphs (a) through (d) of this section for each reciprocating compressor affected facility.

(a) * * *

(3) Collect the VOC emissions from the rod packing using a rod packing emissions collection system that operates under negative pressure and route the rod packing emissions to a process through a closed vent system that meets the requirements of § 60.5411a(a) and (d).

* * * * *

■ 12. Section 60.5390a is amended by revising the section heading and introductory text to read as follows:

§ 60.5390a What VOC standards apply to pneumatic controller affected facilities?

For each pneumatic controller affected facility you must comply with the VOC standards, based on natural gas as a surrogate for VOC, in either paragraph (b)(1) or (c)(1) of this section, as applicable. Pneumatic controllers meeting the conditions in paragraph (a) of this section are exempt from the requirements in paragraph (b)(1) or (c)(1) of this section.

* * * * *

■ 13. Section 60.5393a is amended by revising the section heading and introductory text to read as follows:

§ 60.5393a What VOC standards apply to pneumatic pump affected facilities?

For each pneumatic pump affected facility you must comply with the VOC standards, based on natural gas as a surrogate for VOC, in either paragraph (a) or (b) of this section, as applicable, on or after November 30, 2016.

* * * * *

■ 14. Section 60.5397a is amended by revising the section heading and introductory text to read as follows:

§ 60.5397a What fugitive emissions VOC standards apply to the affected facility which is the collection of fugitive emissions components at a well site and the affected facility which is the collection of fugitive emissions components at a compressor station?

For each affected facility under § 60.5365a(i) and (j), you must reduce VOC emissions by complying with the requirements of paragraphs (a) through (j) of this section. The requirements in this section are independent of the closed vent system and cover requirements in § 60.5411a.

* * * * *

■ 15. Section 60.5398a is amended by revising the section heading and paragraphs (a) and (d)(1)(xi) to read as follows:

§ 60.5398a What are the alternative means of emission limitations for VOC from well completions, reciprocating compressors, the collection of fugitive emissions components at a well site and the collection of fugitive emissions components at a compressor station?

(a) If, in the Administrator's judgment, an alternative means of emission limitation will achieve a reduction in VOC emissions at least equivalent to the reduction in VOC emissions achieved under §§ 60.5375a, 60.5385a, and 60.5397a, the Administrator will publish, in the **Federal Register**, a notice permitting the use of that alternative means for the purpose of compliance with §§ 60.5375a, 60.5385a, and 60.5397a. The notice may condition permission on requirements related to the operation and maintenance of the alternative means.

* * * * *

(d) * * *

(1) * * *

(xi) Operation and maintenance procedures and other provisions necessary to ensure reduction in VOC emissions at least equivalent to the reduction in VOC emissions achieved under § 60.5397a.

* * * * *

■ 16. Section 60.5400a is amended by revising the section heading and paragraph (c) to read as follows:

§ 60.5400a What equipment leak VOC standards apply to affected facilities at an onshore natural gas processing plant?

* * * * *

(c) You may apply to the Administrator for permission to use an alternative means of emission limitation that achieves a reduction in emissions of VOC at least equivalent to that achieved by the controls required in this subpart according to the requirements of § 60.5402a.

* * * * *

■ 17. Section 60.5401a is amended by revising the section heading to read as follows:

§ 60.5401a What are the exceptions to the equipment leak VOC standards for affected facilities at onshore natural gas processing plants?

* * * * *

■ 18. Section 60.5402a is amended by revising the section heading and paragraphs (a) and (d)(2) introductory text to read as follows:

§ 60.5402a What are the alternative means of emission limitations for VOC equipment leaks from onshore natural gas processing plants?

(a) If, in the Administrator's judgment, an alternative means of emission limitation will achieve a reduction in VOC emissions at least equivalent to the reduction in VOC emissions achieved under any design, equipment, work practice or operational standard, the Administrator will publish, in the **Federal Register**, a notice permitting the use of that alternative means for the purpose of compliance with that standard. The notice may condition permission on requirements related to the operation and maintenance of the alternative means.

* * * * *

(d) * * *

(2) The application must include operation, maintenance, and other provisions necessary to assure reduction in VOC emissions at least equivalent to the reduction in VOC emissions achieved under the design, equipment, work practice or operational standard in paragraph (a) of this section by including the information specified in paragraphs (d)(2)(i) through (x) of this section.

* * * * *

■ 19. Section 60.5410a is amended by revising paragraphs (a) introductory text, (b)(1), (d) introductory text, and (f) to read as follows:

§ 60.5410a How do I demonstrate initial compliance with the standards for my well, centrifugal compressor, reciprocating compressor, pneumatic controller, pneumatic pump, storage vessel, collection of fugitive emissions components at a well site, collection of fugitive emissions components at a compressor station, and equipment leaks and sweetening unit affected facilities at onshore natural gas processing plants?

* * * * *

(a) To achieve initial compliance with the VOC standards for each well completion operation conducted at your well affected facility you must comply with paragraphs (a)(1) through (4) of this section.

* * * * *

(b)(1) To achieve initial compliance with standards for your centrifugal compressor affected facility you must reduce VOC emissions from each centrifugal compressor wet seal fluid degassing system by 95.0 percent or greater as required by § 60.5380a(a) and as demonstrated by the requirements of § 60.5413a.

* * * * *

(d) To achieve initial compliance with VOC emission standards for your pneumatic controller affected facility you must comply with the requirements specified in paragraphs (d)(1) through (6) of this section, as applicable.

* * * * *

(f) For affected facilities at onshore natural gas processing plants, initial compliance with the VOC standards is demonstrated if you are in compliance with the requirements of § 60.5400a.

* * * * *

■ 20. Section 60.5412a is amended by paragraphs (a)(1)(i) and (a)(2) to read as follows:

§ 60.5412a What additional requirements must I meet for determining initial compliance with control devices used to comply with the emission standards for my centrifugal compressor, and storage vessel affected facilities?

* * * * *

(a) * * *

(1) * * *

(i) You must reduce the mass content of VOC in the gases vented to the device by 95.0 percent by weight or greater as determined in accordance with the requirements of § 60.5413a(b), with the exceptions noted in § 60.5413a(a).

* * * * *

(2) Each vapor recovery device (*e.g.,* carbon adsorption system or condenser) or other non-destructive control device must be designed and operated to reduce the mass content of VOC in the gases vented to the device by 95.0 percent by weight or greater as determined in accordance with the requirements of § 60.5413a(b). As an alternative to the performance testing requirements in § 60.5413a(b), you may demonstrate initial compliance by conducting a design analysis for vapor recovery devices according to the requirements of § 60.5413a(c).

* * * * *

■ 21. Section 60.5413a is amended by revising paragraph (d)(11)(iii) to read as follows:

§ 60.5413a What are the performance testing procedures for control devices used to demonstrate compliance at my centrifugal compressor and storage vessel affected facilities?

* * * * *

(d) * * *

(11) * * *

(iii) A manufacturer must demonstrate a destruction efficiency of at least 95 percent for THC, as propane. A control device model that demonstrates a destruction efficiency of 95 percent for THC, as propane, will meet the control requirement for 95-percent destruction of VOC (if applicable) required under this subpart.

* * * * *

■ 22. Section 60.5415a is amended by revising paragraphs (b)(1) and (f) to read as follows:

§ 60.5415a How do I demonstrate continuous compliance with the standards for my well, centrifugal compressor, reciprocating compressor, pneumatic controller, pneumatic pump, storage vessel, collection of fugitive emissions components at a well site, and collection of fugitive emissions components at a compressor station affected facilities, and affected facilities at onshore natural gas processing plants?

* * * * *

(b) * * *

(1) You must reduce VOC emissions from the wet seal fluid degassing system by 95.0 percent or greater.

* * * * *

(f) For affected facilities at onshore natural gas processing plants, continuous compliance with VOC requirements is demonstrated if you are in compliance with the requirements of § 60.5400a.

* * * * *

■ 23. Section 60.5420a is amended by revising paragraph (c)(5)(iv) to read as follows:

§ 60.5420a What are my notification, reporting, and recordkeeping requirements?

* * * * *

(c) * * *

(5) * * *

(iv) For storage vessels that are skid-mounted or permanently attached to something that is mobile (such as trucks, railcars, barges, or ships), records indicating the number of consecutive days that the vessel is located at a site in the Crude Oil and Natural Gas source category. If a storage vessel is removed from a site and, within 30 days, is either returned to the site or replaced by another storage vessel at the site to serve the same or similar function, then the entire period since the original storage vessel was first located at the site, including the days when the storage vessel was removed, will be added to the count towards the number of consecutive days.

* * * * *

■ 24. Section 60.5421a is amended by revising the section heading to read as follows:

§ 60.5421a What are my additional recordkeeping requirements for my affected facility subject to VOC requirements for onshore natural gas processing plants?

* * * * *

■ 25. Section 60.5422a is amended by revising the section heading to read as follows:

§ 60.5422a What are my additional reporting requirements for my affected facility subject to VOC requirements for onshore natural gas processing plants?

* * * * *

■ 26. Section 60.5430a is amended by:

■ a. Revising the definition for *Compressor station.*

■ b. Removing the definition for *Crude oil and natural gas source category.*

■ c. Adding the definition for *Crude Oil and Natural Gas Production source category* in alphabetical order.

■ d. Revising the definitions for *Equipment* and *Fugitive emissions component.*

■ e. Adding the definition for *Natural gas transmission and storage segment* in alphabetical order.

The revisions and additions read as follows:

§ 60.5430a What definitions apply to this subpart?

* * * * *

Compressor station means any permanent combination of one or more compressors that move natural gas at increased pressure through gathering pipelines. This includes, but is not limited to, gathering and boosting stations. The combination of one or more compressors located at a well site, or located at an onshore natural gas processing plant, is not a compressor station for purposes of § 60.5397a.

* * * * *

Crude Oil and Natural Gas Production source category means:

(1) Crude oil production, which includes the well and extends to the point of custody transfer to the crude oil transmission pipeline or any other forms of transportation; and

(2) Natural gas production and processing, which includes the well and extends to, but does not include, the point of custody transfer to the natural gas transmission and storage segment.

* * * * *

Equipment, as used in the standards and requirements in this subpart relative to the equipment leaks of VOC from onshore natural gas processing plants, means each pump, pressure relief device, open-ended valve or line, valve, and flange or other connector that is in VOC service or in wet gas service, and any device or system required by those same standards and requirements in this subpart.

* * * * *

Fugitive emissions component means any component that has the potential to emit fugitive emissions of VOC at a well site or compressor station, including valves, connectors, pressure relief devices, open-ended lines, flanges, covers, and closed vent systems not subject to § 60.5411 or § 60.5411a, thief hatches or other openings on a controlled storage vessel not subject to § 60.5395 or § 60.5395a, compressors, instruments, and meters. Devices that vent as part of normal operations, such as natural gas-driven pneumatic controllers or natural gas-driven pumps, are not fugitive emissions components, insofar as the natural gas discharged from the device's vent is not considered a fugitive emission. Emissions originating from other than the device's vent, such as the thief hatch on a controlled storage vessel, would be considered fugitive emissions.

* * * * *

Natural gas transmission and storage segment means the transport or storage of natural gas prior to delivery to a ''local distribution company custody transfer station'' (as defined in this section) or to a final end user (if there is no local distribution company custody transfer station). For the purposes of this subpart, natural gas enters the natural gas transmission and storage segment after the natural gas processing plant, when present. If no natural gas processing plant is present, natural gas enters the natural gas transmission and storage segment after the point of ''custody transfer'' (as defined in this section). A compressor station that transports natural gas prior to the point of ''custody transfer'' or to a natural gas processing plant (if present) is not considered a part of the natural gas transmission and storage segment.

* * * * *

[FR Doc. 2020–18114 Filed 9–9–20; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[EPA–HQ–OAR–2017–0483; FRL–10013–60–OAR]

RIN 2060–AT54

Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Reconsideration

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This action finalizes amendments to the new source performance standards (NSPS) for the oil and natural gas sector. The Environmental Protection Agency (EPA) granted reconsideration on the fugitive emissions requirements, well site pneumatic pump standards, requirements for certification of closed vent systems (CVS) by a professional engineer (PE), and the provisions to apply for the use of an alternative means of emission limitation (AMEL). This final action includes amendments as a result of the EPA's reconsideration of the issues associated with the above mentioned four subject areas and other issues raised in the reconsideration petitions for the NSPS, as well as amendments to streamline the implementation of the rule. This action also includes technical corrections and additional clarifying language in the regulatory text and/or preamble where the EPA concludes further clarification is warranted.

DATES: This final rule is effective on November 16, 2020.

ADDRESSES: The EPA has established a docket for this action under Docket ID No. EPA–HQ–OAR–2017–0483. All documents in the docket are listed on the *https://www.regulations.gov/* website. Although listed, some information is not publicly available, *e.g.,* Confidential Business Information or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the internet and will be publicly available only in hard copy form. Publicly available docket materials are available electronically through *https://www.regulations.gov.* Out of an abundance of caution for members of the public and our staff, the EPA Docket Center and Reading Room are closed to the public, with limited exceptions, to reduce the risk of transmitting COVID–19. Our Docket Center staff will continue to provide remote customer service via email, phone, and webform. For further information and updates on EPA Docket Center services, please visit us online at *https://www.epa.gov/dockets.* The EPA continues to carefully and continuously monitor information from the Center for Disease Control, local area health departments, and our Federal partners so that we can respond rapidly as conditions change regarding COVID–19.

FOR FURTHER INFORMATION CONTACT: For questions about this action, contact Ms. Karen Marsh, Sector Policies and Programs Division (E143–05), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711; telephone number: (919) 541–1065; fax number: (919) 541–0516; and email address: *marsh.karen@epa.gov.*

SUPPLEMENTARY INFORMATION:

Preamble acronyms and abbreviations. A number of acronyms and terms 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:

AMEL Alternative Means of Emission Limitation
ANSI American National Standards Institute
AVO Auditory, Visual, and Olfactory
boe Barrels of Oil Equivalent
BSER Best System of Emissions Reduction
CAA Clean Air Act
CAPP Canadian Association of Petroleum Producers
CEDRI Compliance and Emissions Data Reporting Interface
CFR Code of Federal Regulations
CO_2 Eq. Carbon dioxide equivalent
CPI Consumer Price Indices
CVS Closed Vent System
DOE Department of Energy
EAV Equivalent Annualized Value
EPA Environmental Protection Agency
FEAST Fugitive Emissions Abatement Simulation Toolkit
GHG Greenhouse Gases
GHGI Greenhouse Gas Inventory
HAP Hazardous Air Pollutant(s)
ITRC Interstate Technology and Regulatory Council
LDAR Leak Detection and Repair
METEC Methane Emissions Technology Evaluation Center
NEMS National Energy Modeling System
NSPS New Source Performance Standards
NSSN National Standards System Network
NTTAA National Technology Transfer and Advancement Act
OGI Optical Gas Imaging
OMB Office of Management and Budget
PE Professional Engineer
PRA Paperwork Reduction Act
PRD Pressure Relief Device
PRV Pressure Relief Valve
PTE Potential To Emit
PV Present Value
REC Reduced Emissions Completion
RFA Regulatory Flexibility Act
RIA Regulatory Impact Analysis
RTC Responses to Comments
SOCMI Synthetic Organic Chemicals Manufacturing Industry
The Court United States Court of Appeals for the District of Columbia Circuit
tpy Tons Per Year
TSD Technical Support Document
UIC Underground Injection Control
UMRA Unfunded Mandates Reform Act
VOC Volatile Organic Compounds

Organization of this document. The information presented in this preamble is presented as follows:

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I. Executive Summary

A. Purpose of the Regulatory Action

The purpose of this action is to finalize amendments to the NSPS for the Crude Oil and Natural Gas Production source category (located at 40 Code of Federal Regulations (CFR) part 60, subpart OOOOa) based on the EPA's reconsideration of those standards. On June 3, 2016, the EPA published a final rule titled ''Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources; Final Rule,'' at 81 FR 35824 (''2016 NSPS subpart OOOOa''). The 2016 NSPS subpart OOOOa set the standards for reducing emissions of greenhouse gases (GHG), in the form of limitations on methane, and volatile organic compounds (VOC) from the oil and natural gas sources constructed, modified, or reconstructed after September 15, 2015.[1] Following promulgation of the final rule, the Administrator received petitions for reconsideration of several provisions of the 2016 NSPS subpart OOOOa.[2] The EPA granted reconsideration on four issues: (1) The applicability of the fugitive emissions requirements to low production well sites, (2) the process and criteria for requesting approval of an AMEL, (3) the well site pneumatic pump standards, and (4) the requirements for certification of CVS by a PE. On October 15, 2018, the EPA published a proposed rulemaking titled ''Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Reconsideration,'' in which we proposed amendments to the 2016 NSPS subpart OOOOa to address the issues for which reconsideration was granted, as well as other implementation issues and technical corrections. 83 FR 52056. After considering public comments and new data submitted by the commenters, the EPA is finalizing certain amendments to the 2016 NSPS subpart OOOOa as proposed, finalizing other amendments with changes from the proposal in response to comments and new data that were received, and not finalizing some of the proposed amendments in response to comments and new data that were received.

In addition to the amendments described above, this action includes amendments to address other issues raised in the reconsideration petitions for the 2016 NSPS subpart OOOOa and to clarify and streamline implementation of the rule. These amendments relate to the following provisions: Well completions (location of a separator during flowback, screenouts, and coil tubing cleanouts), onshore natural gas processing plants (definition of capital expenditure and monitoring), storage vessels (applicability), and general clarifications (certifying official and recordkeeping and reporting). Lastly, in addition to the amendments addressing reconsideration and implementation issues, the EPA is finalizing technical corrections of inadvertent errors in the 2016 NSPS subpart OOOOa.

In addition to this action, the EPA has published a separate final rule in the **Federal Register** of Monday, September 14, 2020, that finalizes additional amendments to the 2016 NSPS subpart OOOOa which are not addressed by this action. That separate final rule, titled ''Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Review: Final Rule'' (FRL–10013–44–OAR; FR Doc. 2020–18114) is herein referred to as the ''Review Rule.'' Specifically, the Review Rule removes sources in the transmission and storage segment from the source category by revising the definition of the Crude Oil and Natural Gas Production source category, rescinds the standards (including both the VOC and methane requirements) applicable to those sources, and rescinds the methane-specific requirements of the NSPS applicable to sources in the production and processing segments. For further information about these additional amendments, see the final rule published in the *Rules and Regulations* section of the **Federal Register** of Monday, September 14, 2020. Please refer to the Regulatory Impact Analysis (RIA) for both this action and the Review Rule to see the combined impacts of both actions.

B. Summary of the Major Provisions of This Final Rule

Provided below is a summary of each key amendment, clarification, or correction made to the 2016 NSPS subpart OOOOa that is included in this final action.

Well completions. The EPA is finalizing its proposed amendment to 40 CFR 60.5375a(a)(1)(iii) to allow the separator to be nearby during flowback, but the separator must be available and ready for use as soon as it is technically feasible for the separator to function. We are also amending 40 CFR 60.5375a(a)(1)(i) to clarify that the separator that is required during the initial flowback stage may be a production separator as long as it is designed to accommodate flowback. Finally, we are amending the definition of flowback at 40 CFR 60.5430a to exclude screenouts, coil tubing cleanouts, and plug drill outs. As explained in the preamble to the proposed rulemaking, these are functional processes that allow for flowback to begin; as such, they are not part of the flowback. 83 FR 52082.

Pneumatic pumps. The EPA is finalizing an amendment to extend the exemption from control where it is technically infeasible to route pneumatic pump emissions to a control device. The final rule extends this exemption to all pneumatic pump affected facilities at all well sites by removing the reference to greenfield sites in 40 CFR 60.5393a(b) and the greenfield site definition from 40 CFR 60.5430a. Additionally, in order to qualify for the technical infeasibility exemption, the 2016 NSPS subpart OOOOa requires certification by a qualified PE that routing a pneumatic pump to a control device or a process is technically infeasible. 40 CFR 60.5393a(b)(5). This final rule allows certification of technical infeasibility by either a qualified PE or an in-house engineer with expertise on the design and operation of the pneumatic pump.

Storage vessels. This final rule amends the applicability criteria for storage vessel affected facilities by establishing criteria for calculating potential for VOC emissions under different scenarios. Specifically, for individual storage vessels that are part of a controlled tank battery (*i.e.,* two or more storage vessels manifolded together with piping such that all vapors are shared between the headspace of the storage vessels, and where emissions are routed through a CVS to a process or a control device with a destruction efficiency of at least 95.0 percent for VOC emissions) that is subject to a

[1] Docket ID No. EPA–HQ–OAR–2010–0505.

[2] Copies of the petitions are provided in Docket ID No. EPA–HQ–OAR–2017–0483.

legally and practicably enforceable limit, potential VOC emissions may be determined by averaging the emissions from the entire tank battery across the number of storage vessels in the battery. For a controlled tank battery described above, if the average per storage vessel VOC emissions are greater than 6 tons per year (tpy), then all storage vessels in that battery are storage vessel affected facilities. For individual storage vessels that do not meet the criteria described above, the potential VOC emissions is determined according to the proposed criteria, which the EPA is finalizing in this action; where the VOC emissions are greater than 6 tpy, the storage vessel is an affected facility.

CVS. This final rule incorporates the option for owners and operators to demonstrate that the pneumatic pump CVS is operated with no detectable emissions by (1) an annual inspection using EPA Method 21 of appendix A–7 of part 60 (''Method 21''), (2) monthly audio/visual/olfactory (AVO) monitoring, or (3) optical gas imaging (OGI) monitoring at the frequencies specified for fugitive monitoring. Additionally, this final rule incorporates the option for a storage vessel CVS to be monitored by either monthly AVO monitoring or OGI monitoring at the frequencies specified for fugitive monitoring. Finally, this final rule allows for certification of the CVS design and capacity assessment by either a qualified PE or an in-house engineer with expertise on the design and operation of the CVS.

Fugitive emissions requirements. The EPA is finalizing several amendments to the requirements for the collection of fugitive emissions components at well sites and compressor stations. The monitoring frequencies in this final rule are semiannual for well sites and compressor stations, and annual for well sites and compressor stations located on the Alaska North Slope. The final rule excludes low production well sites (where the total combined oil and natural gas production for the well site is at or below 15 barrels of oil equivalent (boe) per day) from fugitive emissions monitoring, as long as they maintain the records specified in the final rule to demonstrate that their total well site production is at or below 15 boe per day. A low production well site that subsequently produces above this threshold is required to comply with the fugitive emissions requirements.

This final rule also finalizes separate initial monitoring requirements for the Alaska North Slope compressor stations, as proposed. Compressor stations located on the Alaska North Slope that start up between September and March must conduct initial monitoring within 6 months of startup or by June 30, whichever is later; compressor stations that start up between April and August must conduct initial monitoring within 90 days of startup. This final rule revises the initial monitoring requirement for well sites and compressor stations not located on the Alaska North Slope by requiring initial monitoring within 90 days of startup. Additionally, this final rule allows fugitive monitoring to stop when all major production and processing equipment is removed from a well site such that it becomes a wellhead-only well site.

In addition to the amendments related to monitoring frequencies, the final rule (1) specifies the events that constitute modifications to an existing separate tank battery surface site (which is a ''well site'' for purposes of well site fugitive emissions requirements); (2) revises the repair requirements to specify that a first attempt at repair must be made within 30 days of identifying fugitive emissions and final repair must be made within 30 days of the first attempt at repair; (3) amends the definition of a well site to exclude third-party equipment located downstream of the custody meter assembly and Underground Injection Control (UIC) Class I non-hazardous and UIC Class II disposal wells from the fugitive emissions requirements; and (4) revises the requirements for the monitoring plan, recordkeeping, and reporting associated with the fugitive emissions requirements.

AMEL. This final rule amends the provisions for application of an AMEL for emerging technologies or for existing state fugitive emissions programs. Additionally, this final rule provides alternative fugitive emissions standards for well sites and compressor stations located in specific states.

Onshore natural gas processing plants. This final rule revises the definition of ''capital expenditure'' at 40 CFR 60.5430a by replacing the equation used to determine the percent of replacement cost, ''Y'', with one that is based on the ratio of consumer price indices (CPI). Additionally, this final rule exempts components that are in VOC service for less than 300 hours/year from monitoring. The EPA is also revising the equipment leak standards for onshore natural gas processing plants (40 CFR 60.5400a) to include the same initial compliance provision that is in the original equipment leak standards for onshore natural gas processing plants. 40 CFR part 60, subpart KKK. That provision, which is codified at 40 CFR 60.632(a), requires compliance ''as soon as practicable but no later than 180 days after initial startup.'' The EPA has not been able to find a record explaining or otherwise indicating that we intended to change this initial compliance deadline for the leak standards at onshore natural gas processing plants when NSPS subparts OOOO and OOOOa were promulgated; accordingly, in these amendments to NSPS subpart OOOOa, the EPA is adding this provision back into the leak standards for onshore natural gas processing plants in NSPS subpart OOOOa at 40 CFR 60.5400a.

Sweetening units. This final rule revises the affected facility description for the sulfur dioxide (SO_2) standards to correctly define such affected facilities as any onshore sweetening unit that processes natural gas produced from either onshore or offshore wells at 40 CFR 60.5365a(g).

C. Costs and Benefits

The EPA has projected the compliance cost reductions, emissions changes, and forgone benefits that may result from the final reconsideration. The projected cost reductions and forgone benefits are presented in detail in the RIA accompanying this final rule. The RIA focuses on the elements of the final rule—the provisions related to fugitive emissions requirements and certification by a PE—that are likely to result in quantifiable cost or emissions changes compared to a baseline that includes the 2016 NSPS subpart OOOOa requirements. We estimated the effects of this final rule for all sources that are projected to change compliance activities under this action for the analysis years 2021 through 2030. The RIA also presents the present value (PV) and equivalent annualized value (EAV) of costs, benefits, and net benefits of this action in 2016 dollars.

A summary of the key results of this final rule is presented in Table 1. Table 1 presents the PV and EAV, estimated using discount rates of 7 and 3 percent, of the changes in benefits, costs, and net benefits, as well as the change in emissions under the final rule. Here, the EPA refers to the cost reductions as the ''benefits'' of this rule and the forgone benefits as the ''costs'' of this rule in Table 1. The net benefits are the benefits (cost reductions) minus the costs (forgone benefits).

TABLE 1—COST REDUCTIONS, FORGONE BENEFITS AND FORGONE EMISSIONS REDUCTIONS OF THE FINAL RULE, 2021 THROUGH 2030

[Millions 2016$]

	7-Percent discount rate		3-Percent discount rate	
	PV	EAV	PV	EAV
Benefits (Total Cost Reductions)	$750	$100	$950	$110
Costs (Forgone Benefits)	19	2.5	71	8.1
Net Benefits [1]	730	97	880	100
Emissions	Forgone Reductions			
Methane (short tons)	450,000			
VOC (short tons)	120,000			
Hazardous Air Pollutant(s) (HAP) (short tons)	4,700			
Methane (million metric tons carbon dioxide equivalent (CO_2 Eq.))	10			

Note: Estimates are rounded to two significant digits and may not sum due to independent rounding.

This final rule is expected to result in benefits (compliance cost reductions) for affected owners and operators. The PV of these benefits (cost reductions), discounted at a 7-percent rate, is estimated to be about $750 million, with an EAV of about $100 million (Table 1). Under a 3-percent discount rate, the PV of cost reductions is $950 million, with an EAV of $110 million (Table 1).

The estimated costs (forgone benefits) include the monetized climate effects of the projected increase in methane emissions under the final rule. The PV of these climate-related costs (forgone benefits), discounted at a 7-percent rate, is estimated to be about $19 million, with an EAV of about $2.5 million (Table 1). Under a 3-percent discount rate, the PV of the climate-related costs (forgone benefits) is about $71 million, with an EAV of about $8.1 million (Table 1). The EPA also expects that there will be increases in VOC and HAP emissions under the proposal. While the EPA expects that the forgone VOC emission reductions may also degrade air quality and adversely affect health and welfare effects associated with exposure to ozone, particulate matter with a diameter of 2.5 micrometers or less ($PM_{2.5}$), and HAP, we did not quantify these effects at this time. This omission should not imply that these forgone benefits do not exist. To the extent that the EPA were to quantify these ozone and particulate matter (PM) impacts, the Agency would estimate the number and value of avoided premature deaths and illnesses using an approach detailed in the Particulate Matter National Ambient Air Quality Standards (NAAQS) and Ozone NAAQS RIA (U.S. EPA, 2012; U.S. EPA, 2015). Such an analysis would account for the distribution of air pollution-attributable risks among populations most vulnerable and susceptible to $PM_{2.5}$ and ozone exposure.

The PV of the net benefits of this rule, discounted at a 7-percent rate, is estimated to be about $730 million, with an EAV of about $97 million (Table 1). Under a 3-percent discount rate, the PV of net benefits is about $880 million, with an EAV of about $100 million (Table 1).

II. General Information

A. Does this action apply to me?

Categories and entities potentially affected by this action include:

TABLE 2—INDUSTRIAL SOURCE CATEGORIES AFFECTED BY THIS ACTION

Category	NAICS code [1]	Examples of regulated entities
Industry	211120	Crude Petroleum Extraction.
	211130	Natural Gas Extraction.
	221210	Natural Gas Distribution.
	486110	Pipeline Distribution of Crude Oil.
	486210	Pipeline Transportation of Natural Gas.
Federal Government		Not affected.
State/local/tribal government		Not affected.

[1] North American Industry Classification System.

This table is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be regulated by this action. Other types of entities not listed in the table could also be affected by this action. To determine whether your entity is affected by this action, you should carefully examine the applicability criteria found in the final rule. If you have questions regarding the applicability of this action to a particular entity, consult the person listed in the **FOR FURTHER INFORMATION CONTACT** section, your air permitting authority, or your EPA Regional representative listed in 40 CFR 60.4 (General Provisions).

B. Where can I get a copy of this document?

This final action is available in the docket at *https://www.regulations.gov/,* Docket ID No. EPA–HQ–OAR–2017–0483. Additionally, following signature by the Administrator, the EPA will post a copy of this final action at *https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry.* This website provides information on all of the EPA's actions related to control of air pollution in the oil and natural gas industry. Following publication in the **Federal Register**, the EPA will post the **Federal Register** version of the final rule and key technical documents at this same website. A redline version of the regulatory language that incorporates the final changes in this action is available in the docket for this action (Docket ID No. EPA–HQ–OAR–2017–0483).

C. What is the Agency's authority for taking this action?

This action, which finalizes amendments to the 2016 NSPS subpart OOOOa, is based on the same legal authorities that the EPA relied upon for the original promulgation of the 2016 NSPS subpart OOOOa. The EPA promulgated the 2016 NSPS subpart OOOOa pursuant to its standard-setting authority under section 111(b)(1)(B) of the Clean Air Act (CAA) and in accordance with the rulemaking procedures in section 307(d) of the CAA. Section 111(b)(1)(B) of the CAA requires the EPA to issue ''standards of performance'' for new sources in a category listed by the Administrator based on a finding that the category of stationary sources causes or contributes significantly to air pollution which may reasonably be anticipated to endanger public health or welfare. In the Review Rule (published in the **Federal Register** of Monday, September 14, 2020), the EPA has interpreted CAA section 111(b)(1)(B) to require a determination that the emissions of any air pollutant not already subject to an NSPS for the source category (or evaluated in association with the listing of the source category) cause or contribute significantly to air pollution which may reasonably be anticipated to endanger public health or welfare. CAA section 111(a)(1) defines ''a standard of performance'' as ''a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirement) the Administrator determines has been adequately demonstrated.'' The standard that the EPA develops, based on the best system of emission reduction (BSER) is commonly a numerical emission limit, expressed as a performance level (*e.g.,* a rate-based standard). However, CAA section 111(h)(1) authorizes the Administrator to promulgate a work practice standard or other requirements, which reflect the best technological system of continuous emission reduction, if it is not feasible to prescribe or enforce a standard of performance. This action includes amendments to the fugitive emissions standards for well sites and compressor stations, which are work practice standards promulgated pursuant to CAA section 111(h)(1). 81 FR 35829.

The final amendments in this document result from the EPA's reconsideration of various aspects of the 2016 NSPS subpart OOOOa. Agencies have inherent authority to reconsider past decisions and to revise, replace, or repeal a decision to the extent permitted by law and supported by a reasoned explanation. *FCC* v. *Fox Televisions Stations, Inc.,* 556 U.S. 502, 515 (2009); *Motor Vehicle Mfrs. Ass'n* v. *State Farm Mutual Auto. Ins. Co.,* 463 U.S. 29, 42 (1983) (''State Farm''). ''The power to decide in the first instance carries with it the power to reconsider.'' *Trujillo* v. *Gen. Elec. Co.,* 621 F.2d 1084, 1086 (10th Cir. 1980); see also, *United Gas Improvement Co.* v. *Callery Properties, Inc.,* 382 U.S. 223, 229 (1965); *Mazaleski* v. *Treusdell,* 562 F.2d 701, 720 (D.C. Cir. 1977).

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 United Stated Court of Appeals for the District of Columbia Circuit by November 16, 2020. 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 for the EPA to convene a proceeding for reconsideration, ''[i]f the person raising an objection can demonstrate to the EPA that it was impracticable to raise such objection within [the period for public comment] or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule.'' Any person seeking to make such a demonstration to us should submit a Petition for Reconsideration to the Office of the Administrator, U.S. EPA, Room 3000, EPA WJC, 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.

III. Background

On June 3, 2016, the EPA published a final rule titled ''Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Source; Final Rule,'' at 81 FR 35824 (''2016 NSPS subpart OOOOa''). The 2016 NSPS subpart OOOOa established standards of performance for GHG and VOC emissions from new, modified, and reconstructed sources in the oil and natural gas sector. For further information on the 2016 NSPS subpart OOOOa, see 81 FR 35824 (June 3, 2016) and associated Docket ID No. EPA–HQ–OAR–2010–0505. Following promulgation of the final rule, the Administrator received petitions for reconsideration of several provisions of the 2016 NSPS subpart OOOOa. Copies of the petitions are provided in the docket for this final rule (Docket ID No. EPA–HQ–OAR–2017–0483). Several states and industry associations also sought judicial review of the rule, and that litigation is currently being held in abeyance. *American Petroleum Institute, et al.* v. *EPA,* No. 13–1108 (D.C. Cir.) (and consolidated cases).

In a letter to the petitioners dated April 18, 2017, the EPA granted reconsideration of the fugitive emissions requirements at well sites and compressor stations.[3] In a subsequent notification, the EPA granted reconsideration of two additional issues: Well site pneumatic pump standards and the requirements for certification of CVS by a PE.[4] On October 15, 2018, the EPA proposed amendments and clarifications to address the issues under reconsideration, as well as issues related to the implementation of the 2016 NSPS subpart OOOOa that have come to the EPA's attention. During this rulemaking, the EPA reviewed additional information, including information in the annual compliance reports submitted for the 2016 NSPS subpart OOOOa and on costs associated with fugitive emissions monitoring. The additional information has allowed the EPA to more accurately assess the emission reductions and costs associated with the fugitive emissions requirements of the 2016 NSPS subpart OOOOa before evaluating revisions in this rulemaking. Further, the EPA used the additional information to update the overall burden estimates for the 2016 NSPS subpart OOOOa, thus, providing a more accurate baseline on which to compare any burden reductions achieved through this final rule. Upon review of the updated cost estimates,

[3] See Docket ID Item No. EPA–HQ–OAR–2010–0505–7730.

[4] 82 FR 25730.

the EPA concludes the burden of the 2016 NSPS subpart OOOOa was underestimated, and this rulemaking provided an opportunity to reduce the burden of the rule, particularly related to the recordkeeping and reporting requirements. This action finalizes amendments that would significantly reduce the recordkeeping and reporting burden of the rule while continuing to assure compliance. This action also addresses several other implementation issues that were raised following promulgation of the 2016 NSPS subpart OOOOa. The EPA is addressing these issues at the same time to provide clarity and certainty for the public and the regulated community regarding these requirements.

IV. Summary of the Final Standards

This final rule amends certain requirements in the 2016 NSPS subpart OOOOa, as discussed in this section. These amendments are effective on November 16, 2020. Therefore, the standards in NSPS subpart OOOOa change from that date forward. Accordingly, after November 16, 2020, all affected facilities that commenced construction, reconstruction, or modification after September 18, 2015 must comply with the 2016 NSPS subpart OOOOa as amended; the previous requirements no longer apply.

A. Well Completions

The 2016 NSPS subpart OOOOa requires that the owner or operator of a well affected facility have a separator on site during the entire flowback period. 40 CFR 60.5375a(a)(1)(iii). The EPA proposed and received supportive comments on allowing the separator to be located in close enough proximity to the well site for use as soon as sufficient flowback is present for the separator to function. Consistent with the proposal, this final rule amends 40 CFR 60.5375a(a)(1)(iii) to allow the separator to be at a nearby centralized facility or well pad that services the well affected facility during flowback as long as the separator can be utilized as soon as it is technically feasible for the separator to function. The EPA is also amending 40 CFR 60.5375a(a)(1)(i) to clarify that the separator that is required during the initial flowback stage may be a production separator as long as it is also designed to accommodate flowback.

The October 15, 2018, proposal also included proposed amendments to the definition of flowback. The 2016 NSPS subpart OOOOa, 40 CFR 60.5430a defines flowback as the process of allowing fluids and entrained solids to flow from a well following a treatment, either in preparation for a subsequent phase of treatment of in preparation for cleanup and returning the well to production. The term flowback also means the fluids and entrained solids that emerge from a well during the flowback process. The flowback period begins when material introduced into the well during the treatment returns to the surface following hydraulic fracturing or refracturing. The flowback period ends when either the well is shut in and permanently disconnected from the flowback equipment or at the startup of production. The flowback period includes the initial flowback stage and the separation flowback stage.

In the October 15, 2018, proposed rulemaking, the EPA explained that screenouts, coil tubing cleanouts, and plug drill outs are functional processes that allow for flowback to begin; as such, they are not part of the flowback. 83 FR 52082. The proposed rulemaking included definitions for screenouts, coil tubing cleanouts, and plug drill outs, as proposed. Specifically, a screenout is an attempt to clear proppant from the wellbore in order to dislodge the proppant out of the well. A coil tubing cleanout is a process where an operator runs a string of coil tubing to the packed proppant within a well and jets the well to dislodge the proppant and provide sufficient lift energy to flow it to the surface. A plug drill-out is the removal of a plug (or plugs) that was used to isolate different sections of the well. The EPA proposed to exclude screenouts, coil tubing cleanouts, and plug drill outs from the definition of flowback. This final rule amends the definition of flowback and finalizes the definitions for screenouts, coil tubing cleanouts, and plug drill outs, as proposed.

This final rule does not include a definition for a permanent separator. The EPA proposed such a definition in conjunction with our proposal to streamline reporting and recordkeeping requirements for flowback routed through production separators (which we referred to as ''permanent separators'' in the proposed rulemaking). As explained in the preamble to the proposed rulemaking, when a production separator is used for both well completions and production, the production separator is connected at the onset of the flowback and stays on after flowback and at the startup of production; in that event, certain reporting and recordkeeping requirements associated with well completions (*e.g.,* information about when a separator is hooked up or disconnected during flowback) would be unnecessary. 83 FR 52082. We, therefore, proposed to remove such unnecessary data reporting and recordkeeping requirements when a ''permanent separator'' (as defined in the proposed rulemaking) is used for flowback. Upon further review, we learned that the term ''permanent separator,'' as defined in our proposed rulemaking, does not accurately describe production separators that are also used during flowback because such production separators may not be permanent fixtures of a site. Therefore, while the final rule streamlines reporting and recordkeeping requirements for flowback routed through production separators, on the condition that those separators are designed to accommodate flowback, it does not include the term ''permanent separator'' or the proposed definition. The details of these streamlined elements are provided in section IV.I.1 of this preamble.

B. Pneumatic Pumps

Under the 2016 NSPS subpart OOOOa, a pneumatic pump located at a non-greenfield site is not required to reduce its emissions by 95 percent if it is technically infeasible to route the pneumatic pump to a control device or process. This final rule expands the technical infeasibility exemption to pneumatic pumps at all well sites by removing the reference to greenfield site in 40 CFR 60.5393a(b) and the associated definition of greenfield site at 40 CFR 60.5430a. For the 2016 NSPS subpart OOOOa, the EPA concluded that circumstances that could otherwise make control of a pneumatic pump technically infeasible at an existing location could be addressed in the design and construction of a new site. In the proposal, the EPA explained petitioners' concerns that, even at greenfield sites, certain scenarios present circumstances where the control of a pneumatic pump may be technically infeasible despite the site being newly designed and constructed. 83 FR 52061. We, therefore, proposed to expand the technical infeasibility provision to apply to pneumatic pumps at all well sites and solicited comments on scenarios where routing a pump to a control device or process would be technically infeasible at greenfield sites. The EPA received numerous comments in support of the proposal. After consideration of the comments and further review of the standards, this action finalizes the proposed exemption from control if it is technically infeasible to route emissions from a pneumatic pump to a control device at all well sites, including greenfield sites. In addition to the reasons specified in the proposal, the EPA has reevaluated the 2016 NSPS subpart OOOOa standards for pneumatic pumps, and it is clear that the EPA did not intend to require the installation of a control device for the sole purpose of controlling emissions from a pneumatic pump, even at greenfield sites. Furthermore, in the 2016 NSPS subpart OOOOa, the assessment of technical infeasibility for a pneumatic pump is conducted within the context of an existing control device, not a control device that might be installed to also accommodate the pneumatic pump emissions. Therefore, the EPA concludes that when determining technical feasibility at any site, the technical feasibility is determined for the routing of pneumatic pump emissions to the controls which are needed for the processes at the site. Moreover, while it is likely uncommon that an owner or operator cannot design a greenfield site with a control device to reduce pneumatic pump emissions (*e.g.,* because the design from conception would be able to include necessary scenarios), the EPA cannot account for every scenario that may occur, especially given the potential intermittent nature of pneumatic pump emissions. Therefore, the EPA agrees with Petitioners and numerous commenters that it is appropriate to allow the owner or operator to demonstrate that it is technically infeasible to route pneumatic pump emissions to a control device or a process at any well site. The owner or operator must justify and provide professional or in-house engineering certification for any site where the control of pneumatic pump emissions is technically infeasible. The expansion of the technical infeasibility provision is reflected in 40 CFR 60.5393a(b), where we are removing paragraphs (b)(1) and (2).

In addition, we are amending paragraph (b)(5) to state that boilers and process heaters are not control devices for the purposes of the pneumatic pump standards. Two commenters stated that boilers and process heaters located at well sites are not inherently designed for the control of emissions and raised concerns that routing pneumatic pump emissions to these devices may result in frequent safety trips and burner flame instability (*i.e.,* high temperature limit shutdowns, loss of flame signal, etc.).[5] The comments further contend that requiring the technical infeasibility evaluation for every boiler and process heater located at a wellsite would result in unnecessary administrative burden since each such evaluation would be raising the same concerns described above. The EPA agrees with the commenters and has revised the standards to state that boilers and process heaters are not considered control devices for the purposes of controlling pneumatic pump emissions.

Additionally, the EPA is finalizing revisions to the certification requirements for the determination that it is technically infeasible to route emissions from pneumatic pumps to a control device or process. The 2016 NSPS subpart OOOOa requires certification of technical infeasibility by a qualified PE; however, the EPA proposed allowing this certification by either a PE or an in-house engineer because in-house engineers may be more knowledgeable about site design and control than a third-party PE. After considering the comments, some supporting and some opposing the proposal, the EPA continues to believe that certification by an in-house engineer is appropriate. We are, therefore, amending the rule to allow certification of technical infeasibility by either a PE or an in-house engineer with expertise on the design and operation of the pneumatic pump.

C. Storage Vessels

The storage vessel standards apply to individual storage vessels with the potential for VOC emissions of 6 tpy or greater. The 2016 NSPS subpart OOOOa requires a calculation of the potential for VOC emissions from individual storage vessels. In the proposal, the EPA sought to address instances where storage vessels are designed and operated as a manifolded battery and to address questions regarding where averaging emissions may be appropriate for the calculation of potential for VOC emissions. This final rule addresses the challenges of calculating the potential for VOC emissions from individual storage vessels that are part of a controlled battery by specifying separate calculation requirements for these storage vessels. Specifically, the final rule allows owners and operators to average the emissions across the number of storage vessels in a controlled battery provided that specific design and operational criteria are met. These specific design and operational criteria include requirements to manifold the vessels such that all vapors are shared between the headspace of the storage vessels and route the collected vapors through a CVS to a process or a control device with a destruction efficiency of at least 95.0 percent for VOC emissions, and must be included in legally and practicably enforceable limits in a permit or other requirement established under a Federal, state, local, or tribal authority. Under the final rule, if these criteria are met, the owner or operator may calculate the average emissions from the individual storage vessels in that battery to determine if the average emissions are greater than 6 tpy. If the average emissions are greater than 6 tpy, then each of the individual storage vessels in that battery is a storage vessel affected facility. However, if the average emissions are less than 6 tpy, then none of the storage vessels in that battery are a storage vessel affected facility.

In addition, the final rule finalizes the proposed methods for calculating the potential for VOC emissions for storage vessels that do not meet the design and operational criteria specified above. Those storage vessels include individual storage vessels, as well as manifolded storage vessels that do not meet the criteria specified (*e.g.,* less than 95-percent control). These storage vessels must determine applicability by calculating their potential for VOC emissions in accordance with the methods specified in this final rule. The calculation of the potential for VOC emissions may take into account legally and practically enforceable limits on storage vessels but must be determined on an individual storage vessel basis without averaging emissions across the number of storage vessels at the site, even if the storage vessels are manifolded together. If the potential for VOC emissions from the individual storage vessel is greater than 6 tpy, then that storage vessel is a storage vessel affected facility. If the potential for VOC emissions from the individual storage vessel is less than 6 tpy, then that storage vessel is not a storage vessel affected facility.

The EPA is also amending the applicability criteria to clarify how owners and operators must determine the potential for VOC emissions for storage vessels located at onshore natural gas processing plants and compressor stations. The 2016 NSPS subpart OOOOa specifies that the calculation is based on the first 30 days of production to an individual storage vessel. We received comments on the proposal that this production period is not an accurate reflection of the potential for VOC emissions from storage vessels not located at a well site. Specifically, onshore natural gas processing plants and compressor stations are designed to process or transport a specific capacity of gas from multiple sites upstream of these facilities. The design capacity is based on planned growth with additional sites coming online over time, which means

[5] See Docket ID Item Nos. EPA–HQ–OAR–2017–0483–0781 and EPA–HQ–OAR–2017–0483–0801.

the storage vessels at gas processing plants and compressor stations do not receive the maximum throughput for which they are designed during the first 30 days of their operation. For these storage vessels, the commenters indicated they have been utilizing forecasting to predict future throughput and emissions when applying for an operating permit. The EPA agrees that the language in the 2016 NSPS subpart OOOOa does not appropriately capture the information needed to make an informed applicability determination for these storage vessels. Therefore, we are revising the final rule to clarify that, for storage vessels located at onshore natural gas processing plants and compressor stations, the potential for VOC emissions may be determined based on the emission limit or throughput limit (as an input for calculating the potential for VOC emissions), established in a legally and practicably enforceable limit, or based on the projected maximum average daily throughput determined using generally accepted engineering models, such as process simulations based on representative or actual liquid analysis to determine volumetric condensate rates from the storage vessels based on the maximum gas throughput capacity of each facility.

D. CVS

The 2016 NSPS subpart OOOOa requires that CVS be operated with no detectable emissions, as demonstrated through specific monitoring requirements associated with the specific affected facilities (*i.e.,* storage vessels, pneumatic pumps, centrifugal compressors, and reciprocating compressors). In the October 15, 2018, proposal, the EPA proposed amending the requirements for CVS associated with pneumatic pumps to require monthly AVO monitoring instead of the required annual Method 21 monitoring, thereby aligning the demonstration requirements for pneumatic pumps with those for storage vessels. 83 FR 52083. The EPA received comments recommending (1) retaining annual Method 21 as an option and (2) including OGI monitoring as an additional option because OGI is already being used to monitor fugitive emissions components at the well site and the CVS can readily be monitored at the same time. Based on these public comments, the EPA is amending the requirements for these no detectable emissions demonstrations for CVS for pneumatic pumps, with some changes from the proposal. Specifically, we are incorporating the option to demonstrate the pneumatic pump CVS is operated with no detectable emissions by an annual inspection using Method 21, monthly AVO monitoring, or OGI monitoring at the frequencies specified in section IV.E of this preamble.

The 2016 NSPS subpart OOOOa requires monthly AVO inspections on CVS for storage vessels to demonstrate operation with no detectable emissions. Similar to CVS for pneumatic pumps, the EPA is adding OGI monitoring at the frequencies specified in section IV.E of this preamble as another option for demonstrating no detectable emissions from CVS for storage vessels.

While the final rule provides these options for demonstrating the operation of the CVS with no detectable emissions, it is important to note that any detection with AVO or any visual image when using OGI is considered an indication of detected emissions. It is not the EPA's intent to allow owners and operators to conduct an inspection using OGI that results in the visual image of emissions, and then follow that inspection with AVO to conclude no emissions are present. If any of the options specified result in detected emissions, the standard of ''no detectable emissions'' is not met.

Additionally, the EPA is finalizing revisions to the certification requirements for CVS design. Specifically, we are amending the rule to allow either a PE or an in-house engineer with expertise on the design and operation of the CVS to certify the design and operation will meet the requirement to route all vapors to the control device or back to the process.

E. Fugitive Emissions at Well Sites and Compressor Stations

1. Monitoring Frequency

The 2016 NSPS subpart OOOOa requires semiannual monitoring and quarterly monitoring for fugitive emissions at well sites and compressor stations, respectively. The EPA proposed amending these monitoring frequencies as follows: (1) Annual monitoring for well sites with total combined production greater than 15 boe per day, (2) biennial monitoring for well sites with total combined production at or below 15 boe per day, and (3) co-proposed semiannual and annual monitoring for compressor stations. Additionally, the EPA proposed to allow owners and operators to stop monitoring at well sites when all of the major production and processing equipment is removed, such that the well site becomes a wellhead-only well site. After considering the comments and additional data, we are not finalizing the proposed changes to the monitoring frequencies for fugitive emissions components at well sites and compressor stations, with two exceptions explained below. The required fugitive monitoring frequencies for the collection of fugitive emissions components located at a well site or compressor station are as follows:

- Semiannual monitoring for well sites, excluding well sites with total production for the site at or below 15 boe per day (herein referred to as ''low production well sites'') and well sites on the Alaska North Slope;
- Semiannual monitoring for compressor stations, excluding those on the Alaska North Slope;
- Annual monitoring for well sites (excluding low production well sites) and compressor stations located on the Alaska North Slope; and
- Monitoring may be stopped once all major production and processing equipment is removed from a well site such that it contains only one or more wellheads.
- Low production well sites are excluded from fugitive monitoring requirements as long as the total production of the well site remains at or below 15 boe per day, as determined on a rolling 12-month basis and demonstrated by the records specified in the final rule. To determine if a well site is a low production well site, the EPA is finalizing the following calculation periods:
  - For a well site that newly triggers the fugitive emissions requirements of the NSPS after the effective date of the rule, or a well site that triggered the 2016 NSPS subpart OOOOa requirements within 11 months prior to the effective date of the rule but does not have 12-months' worth of production data, the total well site production calculation is based on the first 30 days of production;
  - For a well site subject to the fugitive emissions requirements that subsequently has production decline, the total well site production calculation is based on a rolling 12-month average;
  - For a well site that has previously been determined to be low production but later takes an action (*e.g.,* drills a new well, performs a well workover, etc.) that may increase production, the total well site production calculation is based on the first 30 days of production following completion of the action. This re-determination must be completed at any time an action occurs, regardless of the original startup of production date.

2. Modification

The October 15, 2018, proposal did not propose amendments to the events that constitute modifications of the collection of fugitive emissions components located at a well site or a compressor station but did take comment on whether additional clarification is necessary. The EPA's consideration of the comments received did not result in changes to modifications for well sites and compressor stations, therefore, this final rule retains the events currently identified in the 2016 NSPS subpart OOOOa that qualify as modifications of the collection of fugitive emissions components located at a well site or a compressor station.

The 2016 NSPS subpart OOOOa specifies that, for the purposes of fugitive emissions components at a well site, a modification occurs when (1) a new well is drilled at an existing well site, (2) a well is hydraulically fractured at an existing well site, or (3) a well is hydraulically refractured at an existing well site. 40 CFR 60.5365a(i). Because this provision does not specifically address modifications of a well site that is a separate tank battery surface site, the EPA proposed language to address modifications of separate tank battery surface sites. Specifically, the EPA proposed that a modification of a well site that is a separate tank battery surface site occurs when (1) any of the actions listed above for well sites occurs at an existing separate tank battery surface site, (2) a well modified as described above sends production to an existing separate tank battery surface site, or (3) a well site subject to the fugitive emissions requirements removes all major production and processing equipment such that it becomes a wellhead-only well site and sends production to an existing separate tank battery surface site. After considering the comments received related to the proposed modification language relevant for separate tank battery surface sites, the EPA is finalizing this provision as proposed.

3. Initial Monitoring for Well Sites and Compressor Stations

The 2016 NSPS subpart OOOOa requires fugitive emissions monitoring to begin within 60 days of startup of production (for well sites) or startup of a compressor station. The October 15, 2018, proposal did not propose any change to this requirement but solicited comment identifying specific reasons why a change might be appropriate. 83 FR 52075. We received comments stating that well sites and compressor stations do not achieve normal operating conditions within the first 60 days of startup. Commenters suggested a range of options from 90 days to 180 days. Based on these comments, the EPA agrees that maintaining the requirement to conduct initial monitoring within 60 days of startup would not provide as effective of a survey as providing additional time to allow the well site or compressor station to reach normal operating conditions. The purpose of the initial monitoring is to identify any issues associated with installation and startup of the well site or compressor station. By providing sufficient time to allow owners and operators to conduct the initial monitoring survey during normal operating conditions, the EPA expects that there will be more opportunity to identify and repair sources of fugitive emissions, whereas, a partially operating site may result in missed emissions that remain unrepaired for a longer period of time. The additional 30 days provided in this final rule will still allow for identification and mitigation of fugitive emissions in a timely manner. Therefore, the final rule requires that initial monitoring be completed within 90 days after the startup of production for well sites and 90 days after the startup of a compressor station. Additionally, for low production well sites that take an action which subsequently increases production above 15 boe per day based on the first 30 days of production following the action, the final rule requires that initial monitoring be completed within 90 days after the startup of production following the action.

4. Repair Requirements

This final rule amends the fugitive emissions repair requirements. The 2016 NSPS subpart OOOOa requires repair within 30 days of identifying fugitive emissions and a resurvey to verify that the repair was successful within 30 days of the repair. In the proposal, the EPA proposed to require a first attempt at repair within 30 days of identifying fugitive emissions and final repair, including the resurvey to verify repair, within 60 days of identifying fugitive emissions. We proposed these revisions because stakeholders raised questions on whether emissions identified during the resurvey would result in noncompliance with the repair requirement. The EPA agreed that repairs should be verified as successful prior to the repair deadline, therefore, we proposed a definition of repair that includes the resurvey. The net result of the proposal was that sources would have up to 60 days to complete repairs, which was an increase from the 2016 NSPS subpart OOOOa requirement of 30 days. We received comments from owners and operators that a total of 60 days was not necessary to complete a successful repair, therefore, this final rule amends the fugitive emissions repair requirements with changes from the proposal. Specifically, we are finalizing the proposal that a first attempt at repair is required within 30 days of identifying fugitive emissions and requiring final repair within 30 days of the first attempt at repair. While this final rule would still allow up to a total of 60 days to complete repairs, several owners and operators indicated in their comments that the majority of repairs are completed onsite during the time of the monitoring survey. We are also finalizing as proposed definitions for the terms ''first attempt at repair'' and ''repaired.'' Specifically, the definition of ''repaired'' includes the verification of successful repair through a resurvey of the fugitive emissions component.

The EPA is also amending the requirements for when delayed repairs must be completed. The 2016 NSPS subpart OOOOa, as amended on March 12, 2018,[6] specifies that where the repair of a fugitive emissions component is ''technically infeasible, would require a vent blowdown, a compressor station shutdown, a well shutdown or well shut-in, or would be unsafe to repair during operation of the unit, the repair must be completed during the next scheduled compressor station shutdown, well shutdown, well shut-in, after a planned vent blowdown, or within 2 years, whichever is earlier.''[7] The EPA did not propose any additional revisions to this provision, but solicited comment on whether additional changes were necessary. 83 FR 52076. We received comments expressing concerns with requiring repairs during the next scheduled compressor station shutdown, without regard to whether the shutdown is for maintenance purposes. The commenters stated that repairs must be scheduled and that where a planned shutdown is for reasons other than scheduled maintenance, completion of the repairs during that shutdown may be difficult and disrupt gas transmission. The EPA agrees that requiring the completion of delayed repairs only during those scheduled compressor station shutdowns where maintenance activities are scheduled is reasonable and anticipates that these maintenance shutdowns occur on a regular schedule. Therefore, the final rule requires completion of delayed repairs during the ''next scheduled compressor station

[6] 83 FR 10638.

[7] 40 CFR 60.5397a(h)(2).

shutdown for maintenance, scheduled well shutdown, scheduled well shut-in, after a scheduled vent blowdown, or within 2 years, whichever is earliest.''

5. Definitions Related to Fugitive Emissions at Well Sites and Compressor Stations

The EPA is finalizing, as proposed, amendments to the definition of well site, for purposes of fugitive emissions monitoring, to exclude equipment owned by third parties and oilfield wastewater disposal wells (referred to as saltwater disposal wells in the proposal). Additionally, based on information received in public comments, the EPA is also amending the definition to exclude oilfield disposal wells used for solid waste disposal. The amended definition for ''well site'' excludes third party equipment from the fugitive emissions requirements by excluding ''the flange immediately upstream of the custody meter assembly and equipment, including fugitive emissions components located downstream of this flange.'' To clarify this exclusion, the final rule defines ''custody meter'' as the meter where natural gas or hydrocarbon liquids are measured for sales, transfers, and/or royalty determination, and the ''custody meter assembly'' as an assembly of fugitive emissions components, including the custody meter, valves, flanges, and connectors necessary for the proper operation of the custody meter, as proposed. The exclusion does not extend to other third-party equipment at a well site that is not associated with the custody meter and custody meter assembly (*e.g.,* dehydrators).

This final rule further amends the definition of a well site to exclude UIC Class I oilfield disposal wells and UIC Class II oilfield wastewater disposal wells. The EPA proposed excluding UIC Class II oilfield wastewater disposal wells because of our understanding that they have negligible fugitive emissions. 83 FR 52077. Commenters suggested that we also should exclude UIC Class I oilfield disposal wells for the same reasons. Both types of disposal wells are permitted through UIC programs under the Safe Drinking Water Act for surface and groundwater protection. The EPA agrees with the commenters that the potential fugitive methane and VOC emissions from UIC Class I oilfield disposal wells are low. Therefore, the final rule includes a definition for UIC Class I oilfield disposal wells. The definition for a UIC Class I oilfield disposal well is a well with a UIC Class I permit that meets the definition in 40 CFR 144.6(a)(2) and receives eligible fluids from oil and natural gas exploration and production operations. Additionally, the EPA is finalizing, as proposed, the definition of UIC Class II oilfield wastewater disposal wells. The definition for a UIC Class II oilfield wastewater disposal well is a well with a UIC Class II permit where wastewater resulting from oil and natural gas production operations is injected into underground porous rock formations not productive of oil or gas, and sealed above and below by unbroken, impermeable strata. Consequently, UIC Class I and UIC Class II disposal facilities without wells that produce oil or natural gas are not considered well sites for the purposes of fugitive emissions requirements.

The EPA is also finalizing, as proposed, the definition of startup of production as it relates to fugitive emissions requirements. Specifically, startup of production is defined as the beginning of initial flow following the end of flowback when there is continuous recovery of salable quality gas and separation and recovery of any crude oil, condensate or produced water, except as otherwise provided herein. For the purposes of the fugitive monitoring requirements of § 60.5397a, startup of production means the beginning of the continuous recovery of salable quality gas and separation and recovery of any crude oil, condensate or produced water.

F. AMEL

1. Incorporation of Emerging Technologies

The EPA is amending the application requirements for requesting the use of an AMEL for well completions, reciprocating compressors, and the collection of fugitive emissions components located at a well site or compressor station. Applications for an AMEL may be submitted by, among others, owners or operators of affected facilities, manufacturers or vendors of leak detection technologies, or trade associations. The application must provide sufficient information to demonstrate that the AMEL achieves emission reductions at least equivalent to the work practice standards in this rule. At a minimum, the application should include field data that encompass seasonal variations, and may be supplemented with modeling analyses, test data, and/or other documentation. The specific work practice(s), including performance methods, quality assurance, the threshold that triggers action, and the mitigation thresholds are also required as part of the application. For example, for a technology designed to detect fugitive emissions, information such as the detection criteria that indicate fugitive emissions requiring repair, the time to complete repairs, and any methods used to verify successful repair would be required.

2. Incorporation of State Fugitive Emissions Programs

This final rule includes alternative fugitive emissions standards for specific state fugitive emissions programs that the EPA has concluded are at least equivalent to the fugitive emissions monitoring and repair requirements at 40 CFR 60.5397a(e), (f), (g), and (h). These alternative fugitive emissions standards may be adopted for certain individual well sites or compressor stations that are subject to fugitive emissions monitoring and repair so long as the source complies with specified Federal requirements applicable to each approved alternative state program. For example, a well site that is subject to the requirements of Pennsylvania General Permit 5A, section G, effective August 8, 2018, could comply with those standards in lieu of the monitoring, repair, recordkeeping, and reporting requirements in the NSPS. However, the company must develop and maintain a fugitive emissions monitoring plan, as required in 40 CFR 60.5397a(c) and (d), and must monitor all of the fugitive emissions components, as defined in 40 CFR 60.5430a, regardless of the components that must be monitored under the alternative standard. Additionally, the facility must submit, as an attachment to its annual report for NSPS subpart OOOOa, the report that is submitted to its state in the format submitted to the state, or the information required in the report for NSPS subpart OOOOa if the state report does not include site-level monitoring and repair information. If a well site is located in the state but is not subject to the state requirements for monitoring and repair (*i.e.,* not obligated to monitor or repair fugitive emissions), then the well site must continue to comply with the requirements of 40 CFR 60.5397a in its entirety.

In addition to providing alternative fugitive emissions standards for well sites and compressor stations located in California, Colorado, Ohio, Pennsylvania, and Texas, and well sites in Utah, these amendments provide application requirements to request alternative fugitive emissions standards as state, local, and tribal programs continue to develop. Applications for alternative fugitive emissions standards based on state, local, or tribal programs may be submitted by any interested person, including individuals, corporations, partnerships, associations, states, or municipalities. Similar to the applications for AMEL for emerging technologies, the application must include sufficient information to demonstrate that the alternative fugitive emissions standards achieve emissions reductions at least equivalent to the fugitive emissions monitoring and repair requirements in this rule. At a minimum, the application must include the monitoring instrument, monitoring procedures, monitoring frequency, definition of fugitive emissions requiring repair, repair requirements, recordkeeping, and reporting requirements. If any of the sections of the regulations or permits approved as alternative fugitive emissions standards are changed at a later date, the state must follow the procedures outlined in 40 CFR 60.5399a to apply for a new evaluation of equivalency.

G. Onshore Natural Gas Processing Plants

1. Capital Expenditure

The EPA is amending the definition of ''capital expenditure'' at 40 CFR 50.5430a by replacing the equation used to determine the percent of replacement cost, ''Y.'' The 2016 NSPS subpart OOOOa contains a definition for ''Y'' that would result in an error, thus, making it difficult to determine whether a capital expenditure had occurred. The EPA proposed to revise the base year in the equation for ''Y'' with the year 2015 and to define ''Y'' as equal to 1 for facilities constructed in the year 2015. Additionally, we solicited comment on an alternative approach that would utilize CPI. While the EPA proposed these specific amendments to the equation used to determine the value of ''Y,'' we received public comments that supported the alternative approach which would more appropriately reflect inflation than the original equation. The EPA solicited comment on this alternative and is finalizing the alternative because we agree it is appropriate. The final equation for ''Y'' is based on the CPI, where ''Y'' equals the CPI of the date of construction divided by the most recently available CPI of the date of the project, or ''CPI_N/CPI_{PD}.'' Further, the final rule specifies that the ''annual average of the consumer price index for all urban consumers (CPI–U), U.S. city average, all items'' must be used for determining the CPI of the year of construction, and the ''CPI–U, U.S. city average, all items'' must be used for determining the CPI of the date of the project. This amendment clarifies that the comparison of costs is between the original date of construction of the process unit and the date of the project which adds equipment to the process unit.

2. Equipment in VOC Service Less Than 300 Hours per Year (hr/yr)

The October 15, 2018, proposal included an exemption from the requirements for equipment leaks at onshore natural gas processing plants. Specifically, the EPA proposed an exemption from monitoring for equipment that an owner or operator designates as being in VOC service less than 300 hr/yr. 83 FR 52086. The EPA received comments supporting this proposed exemption; therefore, we are amending the final rule as proposed. This exemption applies to equipment at onshore natural gas processing plants that is used only during emergencies, used as a backup, or that is in service only during startup and shutdown.

3. Initial Compliance Period

The EPA is amending NSPS subpart OOOOa to specify that the initial compliance deadline for the equipment leak standards for onshore natural gas processing plants is 180 days. Specifically, the EPA is including in NSPS subpart OOOOa the provision requiring compliance ''as soon as practicable, but no later than 180 days after initial startup'' that is already in 40 CFR 60.632(a), which is part of subpart KKK of the part, ''Standards of Performance for Equipment Leaks of VOC from Onshore Natural Gas Processing Plants for which Construction, Reconstruction, or Modification Commenced After January 20, 1984, and on or before August 23, 2011'' (NSPS subpart KKK). In 2012, the EPA revised the standards in NSPS subpart KKK with the promulgation of NSPS subpart OOOO [8] by lowering the leak definition for valves from 10,000 parts per million (ppm) to 500 ppm and requiring the monitoring of connectors. 77 FR 49490, 49498. While no changes to the compliance deadlines were made or discussed in NSPS subpart OOOO, 40 CFR 60.632(a) was not included in NSPS subpart OOOO and, as a result, was also not included in NSPS subpart OOOOa. During the rulemaking for NSPS subpart OOOOa, the EPA declined a request to include the language in 40 CFR 60.632(a) in NSPS subpart OOOOa, explaining that such inclusion was not necessary because NSPS subpart OOOOa already incorporates by reference a similar statement (*i.e.,* 40 CFR 60.482–1a(a)) which requires each owner and operator to ''demonstrate compliance . . . within 180 days of initial startup,'' 80 FR 56593, 56647–8. In reassessing the issue, the EPA notes that NSPS subpart KKK includes both 40 CFR 60.632(a) and 40 CFR 60.482–1(a), a provision that is the same as 40 CFR 60.482–1a(a), suggesting that at the time of promulgation of NSPS subpart KKK, the EPA did not think that 40 CFR 60.482–1(a) (and 40 CFR 60.482–1a(a)) make 40 CFR 60.632(a) redundant or unnecessary. To remain consistent with NSPS subpart KKK, the EPA is amending NSPS subpart OOOOa to include a provision similar to 40 CFR 60.632(a).

The final rule requires monitoring to begin as soon as practicable, but no later than 180 days after the initial startup of a new, modified, or reconstructed process unit at an onshore natural gas processing plant. Once started, monitoring must continue with the required schedule. For example, if pumps are monitored by month 3 of the initial startup period, then monthly monitoring is required from that point forward. This initial compliance period is different than the compliance requirements for newly added pumps and valves within a process unit that is already subject to a leak detection and repair (LDAR) program. Initial monitoring for those newly added pumps and valves is required within 30 days of the startup of the pump or valve (*i.e.,* when the equipment is first in VOC service).

H. Sweetening Units

This final rule revises the applicability criteria for the SO_2 standards for sweetening units to correctly define an affected facility as any onshore sweetening unit that processes natural gas produced from either onshore or offshore wells. Sweetening units are used to convert hydrogen sulfide (H_2S) in acid gases (*i.e.,* H_2S and CO_2) that are separated from natural gas by a sweetening process (*e.g.,* amine treatment) into elemental sulfur in the Claus process.[9] These units can exist anywhere in the production and processing segment of the source category, including as stand-alone processing facilities that do not extract or fractionate natural gas liquids from field gas. The SO_2 standards for onshore sweetening units were first promulgated in 1985 and codified in 40 CFR part 60, subpart LLL. In 2012,

[8] ''Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution for Which Construction, Modification or Reconstruction Commenced After August 23, 2011, and on or before September 18, 2015.''

[9] See Docket ID Item No. EPA–HQ–OAR–2010–0505–0045.

based on our review of the standards, the EPA tightened the SO_2 standards, which were codified in NSPS subpart OOOO and later carried over to NSPS subpart OOOOa. In the process of finalizing this current rulemaking to amend NSPS subpart OOOOa, the EPA discovered that NSPS subpart OOOOa inexplicably limits the applicability of the SO_2 standards to only those sweetening units that are located at onshore natural gas processing plants, which NSPS subpart OOOOa defines as ''any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both. . . .'' 40 CFR 60.5430a. NSPS subpart LLL did not contain this limitation, and the EPA did not offer any rationale for creating it during the promulgation of either NSPS subpart OOOO or NSPS subpart OOOOa, nor can we identify any reason why the extraction of natural gas liquids relates in any way to the SO_2 standards such that the standards should only apply to sweetening units located at onshore natural gas processing plants engaged in extraction or fractionation activities. Sweetening units emit SO_2 in the same manner, regardless of whether they are located at an onshore natural gas processing plant or at processing facilities without extraction or fractionation activities. Therefore, the EPA concludes that the limitation was made in error and is now correcting the error by revising the affected facility description for the SO_2 standards to include all onshore sweetening units that process natural gas produced from either onshore or offshore wells.

I. Recordkeeping and Reporting

The EPA is amending NSPS subpart OOOOa to streamline the recordkeeping and reporting requirements as discussed below for the specified affected facilities. These amendments reflect consideration of the public comments received on the proposal.

1. Well Completions

For each well site affected facility that routes flowback entirely through one or more production separators, owners and operators are only required to record and report the following elements:

- Well Completion ID;
- Latitude and longitude of the well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using North American Datum of 1983;
- U.S. Well ID;
- The date and time of the onset of flowback following hydraulic fracturing or refracturing or identification that the well immediately starts production; and
- The date and time of the startup of production.

For periods where salable gas is unable to be separated, owners and operators will also be required to record and report the date and time of onset of flowback, the duration and disposition of recovery, the duration of combustion and venting (if applicable), reasons for venting (if applicable), and deviations.

2. Fugitive Emissions at Well Sites and Compressor Stations

For each collection of fugitive emissions components located at a well site or compressor station, the EPA is amending the recordkeeping and reporting requirements as follows:

- Revise the requirements in 40 CFR 60.5397a(d)(1) to require inclusion of procedures that ensure all fugitive emissions components are monitored during each survey within the monitoring plan.
- Remove the requirement to maintain records of a digital photo of each monitoring survey performed, captured from the OGI instrument used for monitoring.
- Remove the requirement to maintain records of the number and type of fugitive emissions components or digital photo of fugitive emissions components that are not repaired during the monitoring survey. These records are not required once repair is completed and verified with a resurvey.
- Require records of the total well site production for low production well sites.
- Require records of the date of first attempt at repair and date of successful repair.
- Revise reporting to specify the type of site (*i.e.,* well site, low production well site, or compressor station) and when the well site changes status to a wellhead-only well site.
- Remove requirement to report the name or ID of operator performing the monitoring survey.
- Remove requirement to report the number and type of difficult-to-monitor and unsafe-to-monitor components that are monitored during each monitoring survey.
- Remove requirement to report the ambient temperature, sky conditions, and maximum wind speed.
- Remove requirement to report the date of successful repair.
- Remove requirement to report the type of instrument used for resurvey.

In addition to streamlining the recordkeeping and reporting requirements, the EPA is also finalizing the form that is used for submitting annual reports through the Compliance and Emissions Data Reporting Interface (CEDRI) with this final rule. Per the requirement in 40 CFR 60.5420a(b)(11), affected facilities must submit all subsequent reports via CEDRI, once the form has been available in CEDRI for at least 90 calendar days. The EPA anticipates that the deadline to begin submitting subsequent annual reports required by 40 CFR 60.5420a(b) through CEDRI will be [INSERT DATE 90 DAYS AFTER DATE OF PUBLICATION IN THE **FEDERAL REGISTER**]. However, owners and operators should verify the date that the form becomes available in CEDRI by checking the ''Initial Availability Date'' listed on the CEDRI website (*https://www.epa.gov/electronic-reporting-air-emissions/cedri*).

J. Technical Corrections and Clarifications

The EPA is revising NSPS subpart OOOOa to include the following technical corrections and clarifications.

- Revise 40 CFR 60.5385a(a)(1), 60.5410a(c)(1), 60.5415a(c)(1), and 60.5420a(b)(4)(i) and (c)(3)(i) to clarify that hours or months of operation at reciprocating compressor facilities must be measured beginning with the date of initial startup, the effective date of the requirement (August 2, 2016), or the last rod packing replacement, whichever is latest.
- Revise 40 CFR 60.5393a(b)(3)(ii) to correctly cross-reference paragraph (b)(3)(i) of that section.
- Revise 40 CFR 60.5397a(c)(8) to clarify the calibration requirements when Method 21 of appendix A–7 to part 60 is used for fugitive emissions monitoring.
- Revise 40 CFR 60.5397a(d)(3) to correctly cross-reference paragraphs (g)(3) and (4) of that section.
- Revise 40 CFR 60.5401a(e) to remove the word ''routine'' to clarify that pumps in light liquid service, valves in gas/vapor service and light liquid service, and pressure relief devices in gas/vapor service within a process unit at an onshore natural gas processing plant located on the Alaska North Slope are not subject to any monitoring requirements.
- Revise 40 CFR 60.5410a(e) to correctly reference pneumatic pump affected facilities located at a well site as opposed to pneumatic pump affected facilities not located at a natural gas processing plant (which would include those not at a well site). This correction reflects that the 2016 NSPS subpart OOOOa did not finalize requirements for pneumatic pumps at gathering and boosting compressor stations. 81 FR 35850.

• Revise 40 CFR 60.5411a(a)(1) to remove the reference to § 60.5412a(a) and (c) for reciprocating compressor affected facilities.

• Revise 40 CFR 60.5411a(d)(1) to remove the reference to storage vessels, as this paragraph applies to all the sources listed in 40 CFR 60.5411a(d), not only storage vessels.

• Revise 40 CFR 60.5412a(a)(1) and (d)(1)(iv) to clarify that all boilers and process heaters used as control devices on centrifugal compressors and storage vessels must introduce the vent stream into the flame zone. Additionally, revise 40 CFR 60.5412a(a)(1)(iv) and (d)(1)(iv)(D) to clarify that the vent stream must be introduced with the primary fuel or as the primary fuel to meet the performance requirement option. This is consistent with the performance testing exemption in 40 CFR 60.5413a and continuous monitoring exemption in 40 CFR 60.5417a for boilers and process heaters that introduce the vent stream with the primary fuel or as the primary fuel.

• Revise 40 CFR 60.5412a(c) to correctly reference both paragraphs (c)(1) and (2) of that section, for managing carbon in a carbon adsorption system.

• Revise 40 CFR 60.5413a(d)(5)(i) to reference fused silica-coated stainless steel evacuated canisters instead of a specific name brand product.

• Revise 40 CFR 60.5413a(d)(9)(iii) to clarify the basis for the total hydrocarbon span for the alternative range is propane, just as the basis for the recommended total hydrocarbon span is propane.

• Revise 40 CFR 60.5413a(d)(12) to clarify that all data elements must be submitted for each test run.

• Revise 40 CFR 60.5415a(b)(3) to reference all applicable reporting and recordkeeping requirements.

• Revise 40 CFR 60.5416a(a)(4) to correctly cross-reference 40 CFR 60.5411a(a)(3)(ii).

• Revise 40 CFR 60.5417a(a) to clarify requirements for controls not specifically listed in paragraph (d) of that section.

• Revise 40 CFR 60.5422a(b) to correctly cross-reference 40 CFR 60.487a(b)(1) through (3) and (b)(5).

• Revise 40 CFR 60.5422a(c) to correctly cross-reference 40 CFR 60.487a(c)(2)(i) through (iv) and (c)(2)(vii) through (viii).

• Revise 40 CFR 60.5423a(b) to simplify the reporting language and clarify what data are required in the report of excess emissions for sweetening unit affected facilities.

• Revise 40 CFR 60.5430a to remove the phrase ''including but not limited to'' from the ''fugitive emissions component'' definition. During the 2016 NSPS subpart OOOOa rulemaking, we stated in a response to comment that we are removing this phrase,[10] but we did not do so in that rulemaking and are finalizing that change in this final rule.

• Revise 40 CFR 60.5430a to remove the phrase ''at the sales meter'' from the ''low pressure well'' definition to clarify that when determining the low pressure status of a well, pressure is measured within the flow line, rather than at the sales meter.

• Revise Table 3 to correctly indicate that the performance tests in 40 CFR 60.8 do not apply to pneumatic pump affected facilities.

• Revise Table 3 to include the collection of fugitive emissions components at a well site and the collection of fugitive emissions components at a compressor station in the list of exclusions for notification of reconstruction.

• Revise 40 CFR 60.5393a(f), 60.5410a(e)(8), 60.5411a(e), 60.5415a(b) introductory text and (b)(4), 60.5416a(d), 60.5420a(b) introductory text and (b)(13), and introductory text in §§ 60.5411a and 60.5416a, to remove language associated with the administrative stay we issued under section (d)(7)(B) of the CAA in ''Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources; Grant of Reconsideration and Partial Stay'' (June 5, 2017). The administrative stay was vacated by the U.S. Court of Appeals for the District Of Columbia Circuit on July 3, 2017.

V. Significant Changes Since Proposal

This section identifies significant changes since the proposed rulemaking. These changes reflect the EPA's consideration of over 500,000 comments submitted on the proposal and other information received since the proposal. In this section, we discuss the significant changes since proposal by affected facility type and the rationales for those changes. Additional information related to these changes, such as specific comments and our responses, is in section VI of this preamble and in materials available in the docket.[11]

A. Storage Vessels

In the October 15, 2018, proposal, the EPA proposed clarifications on how to calculate the potential for VOC emissions for purposes of determining whether a storage vessel has the potential for 6 tpy or more of VOC emissions and, therefore, is an affected facility subject to the storage vessels standards under the 2016 NSPS subpart OOOOa. Specifically, the EPA proposed amendments to the definition of ''maximum average daily throughput'' that provided distinct methodologies for calculating the throughput of an individual storage vessel based on how throughput is measured and recorded. We proposed the amendments because owners and operators continued to express confusion over how to calculate this throughput.

Numerous commenters[12] expressed objections to several aspects of the proposed amendments, particularly to the EPA's assumption that averaging emissions across storage vessels in a controlled battery would underestimate a storage vessel's potential VOC emissions. The commenters explained why averaging across storage vessels in controlled batteries has a sound basis in engineering and addresses the EPA's concern about flash emissions, which constitute most of the emissions from storage vessels.

Specifically, the commenters pointed out that tank batteries typically share vapor space (the tank volume above the liquid) and joint piping used to collect generated vapors, which are then routed back to a process or conveyed to a control device, when one is used, or vented through one common pressure relief valve (PRV). For purposes of this discussion, the EPA considers this configuration as a manifolded system that collects and routes vapors across the headspace. (This is different than liquid manifolded systems where liquids can be introduced to any tank in the system.) The commenters noted that vapors flow both into and out of each tank within the battery and into overflow piping on a continuous basis, and vapors will always flow from high pressure areas to low pressure areas when flow is mechanically unrestricted. The commenters explained that, in this configuration, the flash emissions from the first tank will flow into the other tanks and vent line space associated with the battery until the total pressure in the system exceeds the back-pressure of the flare or other control device, or in systems without controls, the PRV.

[10] See Docket ID Item No. EPA–HQ–OAR–2010–0505–7632, Chapter 4, page 4–319.

[11] See Response to Comments (RTC) document and technical support documents (TSD) in Docket ID No. EPA–HQ–OAR–2017–0483.

[12] See Docket ID Item Nos. EPA–HQ–OAR–2017–0483–0773, EPA–HQ–OAR–2017–0483–0775, EPA–HQ–OAR–2017–0483–0780, EPA–HQ–OAR–2017–0483–0801, EPA–HQ–OAR–2017–0483–0996, EPA–HQ–OAR–2017–0483–0999, EPA–HQ–OAR–2017–0483–1006, EPA–HQ–OAR–2017–0483–1009, EPA–HQ–OAR–2017–0483–1236, EPA–HQ–OAR–2017–0483–1243, EPA–HQ–OAR–2017–0483–1248, EPA–HQ–OAR–2017–0483–1261, EPA–HQ–OAR–2017–0483–1343, and EPA–HQ–OAR–2017–0483–1578.

The commenters asserted that only then will the emissions (*i.e.,* the vapors) be released from the PRV if uncontrolled; routed back to a process; or combusted by the control equipment. Therefore, the commenters suggested that because the vapors from individual storage vessels are comingled and not individually emitted from the originating storage vessels, it is appropriate to allow sources to average the emissions across the number of storage vessels in the controlled battery in order to attribute emissions to individual storage vessels.

After considering these comments and subsequent conversations with the commenters,[13] the EPA reevaluated the proposal. Based on this review, the EPA agrees with the commenters that, in certain situations, averaging emissions across a controlled battery may be appropriate for purposes of determining whether to subject the storage vessels in the tank battery to the storage vessel standards in NSPS subpart OOOOa.

In order to fully understand where averaging of emissions across a controlled battery may be appropriate, under this final rule, for purposes of determining whether to subject the storage vessels in the controlled battery to the storage vessel standards in NSPS subpart OOOOa, the EPA considered the level of control that would be achieved where uncontrolled potential emissions are greater than 6 tpy. The standards in the 2016 NSPS subpart OOOOa require reducing uncontrolled emissions from individual storage vessel affected facilities by 95.0 percent.

For controlled batteries, as liquids are introduced to a storage vessel in the system, the vapors transfer to the piping, or common header, enter the common vapor space, and commingle with vapors from other storage vessels in the manifolded system. When the combined vapor pressure in the common header reaches a specified set point, the vapors are typically conveyed through a CVS to either a vapor recovery unit (which routes vapors back to a process) or a control device. Where this controlled battery is designed and operated to route the vapors in this manner, emissions from an individual storage vessel within the controlled battery are indistinguishable from emissions from other storage vessels within the controlled battery; each individual storage vessel does not directly emit (*e.g.,* flash emissions) to the atmosphere. These controlled batteries are typically subject to specific design and operational criteria through a legally and practicably enforceable limit (*e.g.,* through permits or other requirements established through Federal, state, local, or tribal authority). To the extent that the control, through the battery's design and operation, already reduces 95 percent or more of the VOC emissions, no additional emission reductions would be achieved by subjecting each individual storage vessel in the controlled battery operating under legally and practicably enforceable limits to the storage vessel standards in the 2016 NSPS subpart OOOOa. However, the 2016 NSPS subpart OOOOa considers any storage vessel with the potential for VOC emissions greater than 6 tpy, including those with legally and practicably enforceable limits, a storage vessel affected facility. This final rule does not change that 6 tpy applicability threshold, but it does include specific criteria that must be included in the legally and practicably enforceable limit before averaging of emissions will be allowed for the purposes of determining whether the potential for VOC emissions from the individual storage vessels in a controlled tank battery is above the 6 tpy threshold. Specifically, the legally and practicably enforceable limit must require the storage vessels to be (1) manifolded together with piping such that all vapors are shared among the headspaces of the storage vessels, (2) equipped with a CVS that is designed, operated, and maintained to route vapors back to the process or to a control device, and (3) designed and operated to route vapors back to the process or to a control device that reduces VOC emissions by at least 95.0 percent. The EPA concludes that averaging emissions across the number of storage vessels in a controlled battery subject to the design and operational criteria specified above, through a legally and practicably enforceable limit, is the appropriate way to determine if the storage vessels in that battery are affected facilities under NSPS subpart OOOOa. Where the average VOC emissions across the number of storage vessels in the controlled battery is 6 tpy or greater, all of the storage vessels in the controlled battery are storage vessel affected facilities and subject to the requirements for storage vessels in NSPS subpart OOOOa. However, where the average emissions are less than 6 tpy, none of the storage vessels in the controlled battery are storage vessels affected facilities.

For storage vessels that do not meet all of the design and operational criteria specified in this final rule, which includes single storage vessels (whether controlled or not) and storage vessels that are connected in some way but do not meet all of the criteria described above, the final rule requires owners and operators to calculate the potential for VOC emissions on an individual storage vessel basis to determine if the storage vessel is a storage vessel affected facility, as proposed. Where the potential for VOC emissions from a storage vessel is 6 tpy or greater, the storage vessel is a storage vessel affected facility. We have not revised the BSER for storage vessel affected facilities; as a result, the storage vessel standards in the 2016 NSPS subpart OOOOa remain applicable to these storage vessels if their potential for VOC emissions is 6 tpy or greater, based on each individual storage vessel and without averaging across the storage vessels at the site.

The final rule continues to require that an owner or operator calculate the potential for VOC emissions using generally accepted methods for estimating emissions based on the maximum average daily throughput. In this final rule, the EPA is amending the definition of maximum average daily throughput to specify how to determine throughput for the calculation of the potential for VOC emissions. Specifically, this amended definition specifies how storage vessels that commence construction, reconstruction, or modification after the effective date of this final rule must determine the throughput to each individual storage vessel in order to calculate the potential for VOC emissions. This definition is relevant to the individual storage vessels or connected storage vessels that do not meet the specified design and operational criteria defined for controlled tank batteries (*i.e.,* tank batteries that are allowed to average emissions across the tanks in the battery).

In summary, this final rule amends the definition of ''maximum average daily throughput,'' to specify how the potential for VOC emissions are calculated. Additionally, this final rule allows for a calculation of the average VOC emissions to determine the applicability of the storage vessel standards to storage vessels in controlled batteries where specific design and operational criteria are incorporated as legally and practicably enforceable requirements into a permit or other requirement established under Federal, state, local, or tribal authority. The specific design and operational criteria are as follows: (1) The storage vessels are manifolded together with piping such that all vapors are shared

[13] See Memoranda for March 27, 2019 Meeting with American Petroleum Institute, April 9, 2019 Meeting with Hess, and May 1, 2019 Meeting with GPA Midstream located at Docket ID No. EPA–HQ–OAR–2017–0483.

between the headspace of the storage vessels, (2) the storage vessels are equipped with a CVS that is designed, operated, and maintained to route collected vapors back to the process or to a control device, and (3) collected vapors are routed to a process or a control device that achieves at least 95.0-percent control of VOC emissions. If the potential for VOC emissions (or average emissions where applicable) is greater than or equal to 6 tpy, the storage vessel is a storage vessel affective facility.

The amendments discussed above, including the definition of ''maximum average daily throughput,'' apply to storage vessels that commence construction, reconstruction, or modification after the effective date of this final rule, which is November 16, 2020. Owners and operators of storage vessels that commenced construction, reconstruction, or modification after September 18, 2015, and on or before November 16, 2020 may still have uncertainty regarding whether they determined their applicability appropriately. If so, these owners and operators should contact the EPA if they have questions regarding how they previously determined applicability for these sources.

B. Fugitive Emissions at Well Sites and Compressor Stations

The October 15, 2018, proposal included various proposed amendments to the fugitive emissions standards. Two major aspects of those proposed amendments were (1) reduction in the monitoring frequency for well sites and compressor stations and (2) revisions to the monitoring plan, recordkeeping, and reporting requirements. This final rule includes changes from the proposal in both areas. First, the EPA is not finalizing the proposed annual monitoring frequency at non-low production well sites. As explained in more detail below, the EPA concluded that the three areas of uncertainty that were the basis for proposing amendments to the monitoring frequencies for well sites and compressor stations did not result in an overestimate of the cost-effectiveness of the monitoring frequencies in the 2016 NSPS subpart OOOOa, and semiannual monitoring remains cost effective based on the revised cost estimates for well sites with total production greater than 15 boe per day, which are presented in the TSD for this final rule. Therefore, the final rule retains semiannual monitoring for well sites with total production greater than 15 boe per day.

Additionally, the EPA is neither finalizing the proposed biennial monitoring frequency at low production well sites (*i.e.,* well sites with total production at or below 15 boe per day) nor retaining the current semiannual monitoring requirement because monitoring is not cost effective at any frequency for these well sites based on the revised cost estimates. Instead, the final rule requires that a low production well site either maintain its total production at or below 15 boe per day or conduct semiannual monitoring. This requirement applies to well sites that produce at or below 15 boe per day during the first 30 days of production, as well as those sites that experience a decline in production where the total production for the well site, based on a rolling 12-month average, is at or below 15 boe per day, as demonstrated by the records required in the final rule.

Further, the EPA is finalizing the co-proposed semiannual monitoring frequency for gathering and boosting compressor stations. As explained in more detail below in section V.B.4 of the preamble, based on our comparison of the cost-effectiveness of semiannual and quarterly monitoring and consideration of other cost-related factors, we are finalizing semiannual monitoring for gathering and boosting compressor stations. This final rule does not address fugitive emissions monitoring for transmission and storage compressor stations because the Review Rule (published in the **Federal Register** of Monday, September 14, 2020) revises the source category by removing sources in the transmission and storage segment from the category. As such, the Review Rule rescinds the GHG and VOC standards for sources in the transmission and storage segment. Regardless, the TSD for this final action does include relevant updates to the model plants for the transmission and storage compressor stations.

The revised cost estimates for fugitive monitoring of well sites and gathering and boosting compressor stations rely on updates the EPA made to the model plants, including updates that address the areas of uncertainty that we identified in the October 15, 2018, proposal, as well as the revisions to the monitoring plan, recordkeeping, and reporting requirements we are making in this final rule, which reduce administrative burden without compromising our ability to determine compliance with the standards. This section describes the analyses and resulting amendments to the fugitive emissions standards in this final rule.

1. Areas of Uncertainty

In the 2016 NSPS subpart OOOOa, the EPA concluded that a fugitive emissions monitoring and repair program that includes semiannual OGI monitoring at well sites and quarterly monitoring at compressor stations and the repair of any components identified with fugitive emissions was the BSER for the collection of fugitive emissions components at well sites and compressor stations.[14] 81 FR 35826. While the EPA continued to maintain that OGI is the BSER for reducing fugitive emissions at well sites and compressor stations in the October 15, 2018, proposal, we proposed less frequent monitoring after identifying three areas of uncertainty that led to concerns that we might have overestimated the emission reductions, and, therefore, cost effectiveness, of the monitoring frequencies specified in the 2016 NSPS subpart OOOOa. We solicited comments on these three areas of uncertainty, as well as additional information, so that we could better assess the emission reductions that occur at different monitoring frequencies. Additional detailed discussion on the areas of uncertainty is available in the TSD for this final rule.[15]

In the October 15, 2018, proposal, regarding the EPA's cost analysis in the 2016 NSPS subpart OOOOa, we stated that the ''EPA identified three areas of the analysis that raise concerns regarding the emissions reductions: (1) The percent emission reduction achieved by OGI, (2) the occurrence rate of fugitive emissions at different monitoring frequencies, and (3) the initial percentage of fugitive emissions components identified with fugitive emissions.'' 83 FR 52063. Given these areas of concern, we solicited information to further refine our analysis and reduce or eliminate these uncertainties. Several commenters provided information that the EPA used to evaluate each of these areas for this final rule.

Reductions using OGI. In the October 15, 2018, proposal, the EPA maintained the estimates for emissions reductions achieved when using OGI at any type of site, which are 30 percent for biennial monitoring, 40 percent for annual monitoring, 60 percent for semiannual monitoring, and 80 percent for quarterly monitoring. As stated in the proposal, one stakeholder asserted that annual monitoring was more appropriate for compressor stations than the required quarterly monitoring. This stakeholder stated that the estimated control

[14] The rule allows the use of Method 21 as an alternative to OGI but did not conclude Method 21 was BSER because OGI was found to be more cost effective. See 81 FR 35856.

[15] See TSD located at Docket ID No. EPA–HQ–OAR–2017–0483.

efficiency for quarterly monitoring should be 90 percent (instead of 80 percent) and annual monitoring should be 80 percent (instead of 40 percent), based on the stakeholder's interpretation of results from a study conducted by the Canadian Association of Petroleum Producers (CAPP).[16] In response to this information, the EPA reviewed the CAPP report and was unable to conclude that annual OGI monitoring would achieve 80-percent emissions reductions, as stated by the stakeholder.[17] In its submission of public comments on the proposal, and in subsequent clarifying discussions, the stakeholder continued to assert that the EPA had understated the emissions reductions achieved with annual monitoring.[18] As discussed in the TSD,[19] we have reevaluated the information provided in the CAPP report and are still unable to conclude that the CAPP report demonstrates that annual OGI monitoring would achieve 80-percent emissions reductions. In brief, we concluded that the results of the CAPP report indicate that quarterly monitoring could achieve 92-percent emission reductions while annual monitoring could achieve 56-percent emission reductions based on attributing the recommended frequencies at which the components at compressor stations should be monitored to the emissions reported for those component types. However, as stated in our discussion in the TSD, these emissions reductions may also be due to factors such as improved emissions factors and not actual emissions reductions resulting from monitoring and repair.

Another commenter provided information related to the emissions reductions achieved when using OGI at the various monitoring frequencies.[20] The commenter referenced a study performed by Dr. Arvind Ravikumar as supporting the EPA's estimates of emissions reductions for annual and semiannual monitoring using OGI.[21] This study utilized the Fugitive Emissions Abatement Simulation Toolkit (FEAST) model that was developed by Stanford University to simulate emissions reductions achieved at the various monitoring frequencies. The study used information from the EPA's model plant analysis for the 2016 NSPS subpart OOOOa, including the site-level baseline emissions. Emissions reductions were estimated at 32 percent for annual monitoring, 54 percent for semiannual monitoring, and 70 percent for quarterly monitoring, which the EPA considers to be comparable to the EPA's estimated reduction efficiencies for OGI at these monitoring frequencies.

Finally, the EPA updated its analysis of emissions reductions using Method 21 for comparison to the estimated reductions using OGI. As previously stated in the proposal TSD,[22] data from the Synthetic Organic Chemicals Manufacturing Industry (SOCMI) in the 1995 Equipment Leak Protocol Document (1995 Protocol) was used to estimate the Method 21 effectiveness at the various monitoring frequencies. In the proposal TSD, we stated, ''it is not possible to correlate OGI detection capabilities with a Method 21 instrument reading, provided in ppm. However, based on the EPA's current understanding of OGI technology and the types of hydrocarbons found at oil and natural gas well sites and compressor stations, the emission reductions from an OGI monitoring and repair program likely correlate to a Method 21 monitoring and repair program with a fugitive emissions definition somewhere between 2,000 to 10,000 ppm.'' [23] We received comments asserting that the EPA inappropriately used Method 21 effectiveness estimates based on SOCMI to justify the emissions reductions for OGI. In response to these comments, the EPA updated the Method 21 effectiveness estimates using information for the oil and gas industry, as described in the TSD for this final rule.[24] The revised analysis estimates emissions reductions when using Method 21 to be 40 percent for annual monitoring, 54 percent for semiannual monitoring, and 67 percent for quarterly monitoring, when using the average reductions achieved at leak definitions of 500 ppm and 10,000 ppm. While not a direct comparison, the EPA estimates emission reductions using OGI would likely be higher because OGI will detect large emissions, such as emissions from thief hatches on controlled storage vessels, that Method 21 would otherwise not detect.

In conclusion, the EPA performed detailed analyses of the CAPP studies, the FEAST model results, and the updated Method 21 estimates to determine whether changes to the estimated effectiveness of OGI monitoring is appropriate. Based on these analyses, we conclude that the estimated effectiveness percentages of OGI monitoring at the various frequencies are appropriate and do not need adjustment.

Leak occurrence rates. The second uncertainty identified in the October 15, 2018, proposal relates to the occurrence rate of fugitive emissions, or the percentage of components identified with fugitive emissions during each survey. In the proposal, the EPA stated, ''because the model plants assume that the percentage of components found with fugitive emissions is the same regardless of the monitoring frequency, we acknowledge that we may have overestimated the total number of fugitive emissions components identified during each of the more frequent monitoring cycles.'' 83 FR 52064. There are numerous ways the number of leaking components could impact the cost effectiveness of monitoring, including (1) the amount of baseline emissions, (2) the potential emission reductions, and (3) the number of repairs required.

In the 2016 analysis, the EPA assumed that each monitoring survey at a well site would identify four components with fugitive emissions. That is, when a site is monitored annually, we estimated four total components leaking for that year, but if that same site were monitored semiannually, we estimated eight total components leaking for that year. However, we have found that a constant leak occurrence rate is not reflected in our analysis of Method 21 monitoring, the information provided through comments on the proposal, or a review of the annual compliance reports submitted to the EPA for the NSPS subpart OOOOa. Rather, the information demonstrates that occurrence rates differ based on monitoring frequency. For example, the information we reviewed in the annual compliance reports for well site fugitive emissions components demonstrated that, on average, three components were identified as leaking where only one survey had taken place in a 12-month period, and two components were identified as leaking, per survey, where more than one survey had occurred in

[16] CAPP, ''Update of Fugitive Equipment Leak Emission Factors,'' prepared for CAPP by Clearstone Engineering, Ltd., February 2014.

[17] See memorandum, ''EPA Analysis of Fugitive Emissions Data Provided by Interstate Natural Gas Association of America (INGAA),'' located at Docket ID Item No. EPA–HQ–OAR–2017–0483–0060. August 21, 2018.

[18] See Docket ID Item No. EPA–HQ–OAR–2017–0483–1002 and Memorandum for the April 30, 2019 Meeting with INGAA, located at Docket ID No. EPA–HQ–OAR–2017–0483.

[19] See TSD, section 2.4.1.1 for more details at Docket ID No. EPA–HQ–OAR–2017–0483.

[20] See Docket ID Item No. EPA–HQ–OAR–2017–0483–2041.

[21] See Appendix D to Docket ID Item No. EPA–HQ–OAR–2017–0483–2041.

[22] See Docket ID Item No. EPA–HQ–OAR–2017–0483–0040.

[23] See Docket ID Item No. EPA–HQ–OAR–2017–0483–0040, at page 25.

[24] See TSD at Docket ID No. EPA–HQ–OAR–2017–0483.

a 12-month period.[25] These values are similar to those provided by two commenters that provided detailed information on the number of components identified with fugitive emissions at different monitoring frequencies.[26] Therefore, we updated the well site model plant analysis to include an average of three components per annual survey and two components per semiannual survey (for a total of four repairs annually).[27]

In the 2016 analysis, the EPA assigned each type of compressor station (*i.e.,* gathering and boosting, transmission, and storage) a specific leak occurrence rate. While annual compliance reports were submitted for compressor stations complying with NSPS subpart OOOOa, it was not possible to determine which stations were which type. However, for gathering and boosting compressor stations, detailed information was provided by GPA Midstream.[28] While the number of reported leaks varied widely in the dataset, the EPA's analysis of the data demonstrated that, on average, 11 components were identified as leaking during a 12-month period, with monitoring frequencies ranging from monthly to annually.[29] Therefore, we assumed that a total of 11 components, on average, would be identified as leaking over the course of a full year's worth of monitoring, regardless of monitoring frequency. That is, we assumed that if monitoring occurs semiannually, on average, 11 components will be leaking over the course of the two surveys in that year. This estimate takes into account the reported variation in the number of components identified as leaking during each survey. For example, a gathering and boosting compressor station that is monitoring quarterly may identify the following number of components as leaking: Three components in Quarter 1; two components in Quarter 2; four components in Quarter 3; and two components in Quarter 4. If that same gathering and boosting compressor station were monitored annually, then all 11 components would be identified during the one annual survey. This is different than the assumption used in the 2016 NSPS subpart OOOOa. Utilizing the estimate of 11 components identified as leaking over the course of 1 year provides an annual estimate of the repair costs for gathering and boosting compressor stations which is independent of the monitoring survey costs. That is, on average, the same number of repairs are made in a single year, regardless of the frequency of surveys, which helps account for the variability presented in the dataset.

In summary, the EPA is no longer using a linear function for occurrence rates as we did in the proposal or the 2016 NSPS subpart OOOOa. Instead, we have based occurrence rates on available information that is specific to fugitive emissions monitoring frequencies for each type of facility. Specifically, we estimate a total of two repairs (leaking components) at the annual monitoring frequency and three repairs at the semiannual monitoring frequency for well sites. For gathering and boosting compressor stations we estimate that, on average, 11 repairs are necessary over the course of a year. This updated analysis more directly reflects the reality that leak occurrence rates are not linear between frequencies and more appropriately estimates the number of repairs (and, thus, emission reductions and costs) at more frequent monitoring. Thus, the EPA no longer considers leak occurrence rates to raise uncertainties with the analysis or to overestimate emissions.

Initial leak rate. The final uncertainty raised in the October 15, 2018, proposal was the initial percentage of components identified with fugitive emissions (''initial leak rate''). While the EPA did not use an initial leak rate in our estimate of the baseline emissions, one commenter noted that initial leak rate should be considered a key element for understanding potential baseline emissions. The commenter stated its belief that the emissions factor the EPA used to estimate baseline emissions was calculated using an initial leak rate that was too high, thus, biasing the baseline emissions (and the resulting emission reductions) high.[30]

In the 2016 NSPS subpart OOOOa TSD, the EPA stated incorrectly that the model plant analysis assumed an initial leak rate of 1.18 percent.[31] One commenter pointed out that this initial leak rate, which was also cited in the October 15, 2018, proposal, was not the actual estimate used for the model plant analysis. The commenter is correct on this point. The uncontrolled emissions factors for non-thief hatch fugitive emission components the EPA used to estimate model plant emissions are based on Table 2–4 of the Protocol for Equipment Leak Emission Estimates (''Protocol Document'').[32] While the initial leak rates that are inherent in these emissions factors are not specifically stated in the Protocol Document, the commenter performed a back-calculation of the fraction of leaking components using Table 5–7 of the Protocol Document and the weighted leak fraction for all components using the number of each component per model plant. That result, with which the EPA agrees, shows that when using Method 21 and a leak definition of 500 ppm, the estimated initial leak rate is 2.5%, and when using Method 21 and a leak definition of 10,000 ppm, the estimated initial leak rate is 1.65 percent.[33] However, the initial leak rate is only one contributing factor to baseline emissions. Another contributing factor is the magnitude of emissions.

While several commenters[34] provided information on the number or percentage of components identified with fugitive emissions, no commenters provided component-level information on the magnitude of those emissions.[35] In June 2019, a study was published in Elementa that examined fugitive emissions from 67 oil and natural gas well sites and gathering and boosting compressor stations in the Western U.S.[36] As discussed in the TSD, the study included quantification of fugitive emissions from components located at well sites and gathering and boosting compressor stations. The EPA evaluated the measured fugitive emissions from that study for central production, well production, and well site facilities, as defined by the study. We then evaluated the average emissions across those three site types to compare those emissions to

[25] See TSD located at Docket ID No. EPA–HQ–OAR–2017–0483.

[26] See Docket ID Item Nos. EPA–HQ–OAR–2017–0483–0801 and EPA–HQ–OAR–2017–0483–2041.

[27] The 2016 model plant analysis included an evaluation of quarterly monitoring for well sites. Because semiannual monitoring is required, it was not possible to determine the quarterly occurrence rate for well sites using this information. See TSD for additional analysis.

[28] See Docket ID Item No. EPA–HQ–OAR–2017–0483–1261.

[29] See TSD located at Docket ID No. EPA–HQ–OAR–2017–0483.

[30] See Docket ID Item No. EPA–HQ–OAR–2017–0483–0801.

[31] See Docket ID Item No. EPA–HQ–OAR–2010–0505–7631.

[32] See U.S. EPA, ''1995 Protocol for Equipment Leak Emission Estimates Emission Standards'' located at Docket ID Item No. EPA–HQ–OAR–2017–0483–0002.

[33] See memorandum, ''Summary of Data Received on the October 15, 2018 Proposed Amendments to 40 CFR part 60, subpart OOOOa Related to Model Plant Fugitive Emissions.'' February 10, 2020.

[34] See, for example, Docket ID Item Nos. EPA–HQ–OAR–2017–0483–0801, EPA–HQ–OAR–2017–0483–1261, and EPA–HQ–OAR–2017–0483–2041.

[35] See memorandum, ''Summary of Data Received on the October 15, 2018 Proposed Amendments to 40 CFR part 60, subpart OOOOa Related to Model Plant Fugitive Emissions.'' February 10, 2020.

[36] See Pasci, A.P., Ferrara, T., Schwan, K., Tupper, P., Lev-On, M., Smith, R., and Ritter, K., 2019. ''Equipment Leak Detection and Quantification at 67 Oil and Gas Sites in the Western United States.'' Elem Sci Anth, 7(1), p.29 located at *http://doi.org/10.1525/elementa.368.*

the estimated emissions using the average emissions factors from the EPA Protocol Document. The average well site emissions measured in the study were comparable to the model plant well site emissions. Therefore, the EPA determined that the use of the emissions factors from the 1995 Protocol Document was still appropriate and has maintained use of these average emissions factors in the model plant analyses supporting this final rule.

In conclusion, we identified three areas of potential uncertainty in the October 15, 2018, proposal: (1) The effectiveness of OGI at the various frequencies, (2) the leak occurrence rate for each survey, and (3) the initial leak rate. The EPA was concerned that we might have overestimated the emission reductions from the monitoring frequencies in the 2016 NSPS subpart OOOOa due to these three areas of uncertainties. However, after evaluating the data provided by commenters and making the appropriate revisions to our model plant analysis, the EPA no longer believes that these three areas create uncertainty or resulted in an overestimation of emissions reductions.

2. Recordkeeping, Reporting, and Other Administrative Burden Associated With the Fugitive Emissions Program

In addition to proposing reduced monitoring frequencies, the EPA proposed amending the monitoring plan requirements in the 2016 NSPS subpart OOOOa. Specifically, we proposed these amendments to address concerns that the requirements, such as the site map and observation path, resulted in significant costs that increase over time due to the increase in the number of facilities subject to the requirements each year. The EPA proposed allowing alternatives to the site map and observation path that would also ensure that all fugitive components at a site are monitored. 83 FR 52078 and 9. The EPA received comments expressing concern that, in addition to the costs associated with the development and necessary updates of the monitoring plan, the EPA had underestimated the administrative burden associated with the extensive recordkeeping and reporting requirements of the fugitive emissions standards in the 2016 NSPS subpart OOOOa. These commenters stated that this burden represents the largest cost of the fugitive emissions program in the 2016 NSPS subpart OOOOa.[37] In the October 15, 2018, proposed rulemaking, the EPA proposed to streamline certain recordkeeping and reporting requirements in the 2016 NSPS subpart OOOOa to reduce burden on the industry, including the fugitive emissions recordkeeping and reporting. 83 FR 52059. In response to these comments, the EPA re-evaluated the fugitive emissions program, with a focus on identifying areas to reduce unnecessary administrative burden and provide flexibility for future innovation, while retaining sufficient recordkeeping and reporting requirements to assure that affected facilities are complying with the standards. After concluding this re-evaluation, we found that certain requirements were unnecessary and burdensome.

First, we examined the commenters' assertion and supporting information that the EPA underestimated the recordkeeping and reporting costs in both the 2016 NSPS subpart OOOOa and the October 15, 2018, proposal. To better understand the commenters' statements regarding the recordkeeping and reporting costs associated with the 2016 NSPS subpart OOOOa, we reviewed the specific recordkeeping and reporting requirements for the fugitive emissions program, including the monitoring plan. Based on this review, we agree with the commenters that the recordkeeping and reporting burden was underestimated in both the 2016 NSPS subpart OOOOa and the October 15, 2018, proposal, as described below.

In the October 15, 2018, proposal, we had proposed reducing certain monitoring frequencies. While we updated portions of the model plant analysis for fugitive emissions to reflect these proposed changes, we did not make specific changes related to recordkeeping and reporting costs. As shown in the proposal TSD,[38] we estimated that the development of a monitoring plan was a one-time cost of $3,672 per company-defined area, which is estimated as consisting of 22 well sites or seven gathering and boosting compressor stations. We estimated reporting costs to be at $245 per site per year.

Second, we reevaluated the cost burden of the recordkeeping and reporting requirements associated with the fugitive emissions standards in the 2016 NSPS subpart OOOOa prior to considering any additional changes to those standards that might further reduce the cost burden. This step was necessary to provide a correct baseline for comparison when evaluating the burden reductions associated with potential changes to the standards.

Before considering the information provided in the comments, we removed certain line items from the previous analysis as described. We removed the initial and subsequent planning activities because these items were not clearly representative of actual recordkeeping activities that are associated with the fugitive emissions requirements of the rule (*e.g.,* records management systems, tracking components, data review, etc.). We also removed the cost associated with notification of initial compliance status because such notification is not required under the 2016 NSPS subpart OOOOa. Next, we considered the comments and information received on our estimate of the cost to develop a monitoring plan under the 2016 NSPS subpart OOOOa. One commenter provided information on the range of costs that have been incurred by owners and operators to develop a monitoring plan since the rule has been in place.[39] These estimated costs range from $5,600 to $8,800, which is more than our estimate of $3,672. In examining the information provided by the commenter in further detail, we note that hourly rates are higher than the standard labor rate used in EPA's calculations, which would attribute to the difference in costs. Next, commenters dispute our assumption that the monitoring plan is a one-time cost for the company. Several commenters stated while most of the monitoring plan is associated with a one-time cost, the required site map and observation path require frequent updates as the equipment at the site changes. One of these commenters provided an estimate of the cost to develop the initial site map and observation path for an individual site, and the cost of updating these items for each monitoring survey.[40] This information provided estimates that companies have already spent approximately $650 developing the individual site map and observation path for each site and an additional $150 updating these items for each monitoring survey. Based on this information, we agree it is appropriate to account for the necessary updates for

[37] See Docket ID Item No. EPA–HQ–OAR–2017–0483–0016.

[38] See TSD at Docket ID Item No. EPA–HQ–OAR–2017–0483–0040.

[39] See Docket ID No. EPA–HQ–OAR–2017–0483; EPA's ''Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Reconsideration; Proposed Rule''; 83 FR 52056 (October 15, 2018). Dated May 22, 2019, located at Docket ID No. EPA–HQ–OAR–2017–0483.

[40] See Docket ID No. EPA–HQ–OAR–2017–0483; EPA's ''Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Reconsideration; Proposed Rule''; 83 FR 52056 (October 15, 2018). Dated May 22, 2019, located at Docket ID No. EPA–HQ–OAR–2017–0483.

the site map and observation path when estimating the cost burden of the rule. Therefore, we split the monitoring plan costs into three items in our model plant analysis: (1) Develop company-wide fugitive emissions monitoring plan, (2) develop site-specific fugitive monitoring plan (*i.e.,* site map and observation path), and (3) management of change (site map and observation path). Additionally, we applied hourly rates, based on information provided by the commenter, to estimate costs instead of using the flat cost values provided. The updated estimates associated with developing a monitoring plan for well sites under the existing standards are $2,448 to develop the general company-wide monitoring plan (assumes 22 well sites), $400 to develop the site map and observation path for each site, and $184 to update the individual site map and observation path annually (based on semiannual monitoring). This would result in a total cost for development of the monitoring plan for the 22 well site company-defined area of $15,296, including updates to the site map and observation path at the semiannual surveys conducted that first year. For gathering and boosting compressor stations, we estimate it costs $1,530 to develop a company-wide monitoring plan (assumes seven stations per plan), $400 to develop the site map and observation path for each site, and $367 to update the individual site map and observation path annually (based on quarterly monitoring). This would result in a total cost of $6,899 for development of the monitoring plan for the seven gathering and boosting compressor station company-defined area, including updates to the site map and observation path at the quarterly surveys conducted that first year. Based on available information, we believe these costs are representative of the costs to develop and maintain the monitoring plan as required in the 2016 NSPS subpart OOOOa.

We then examined the recordkeeping costs associated with the fugitive emissions requirements. As stated above, we were unable to locate clearly defined estimates for recordkeeping costs for the 2016 NSPS subpart OOOOa, therefore, all costs are new in our baseline estimate of the actual cost of the existing standards and are based on information received from commenters and previous information collected by the Agency for similar programs. There are extensive records required for each survey that is performed, regardless of the frequency; therefore, we recognize that appropriate data management is critical to ensuring compliance with the standards. As explained in the TSD for this final rule,[41] we evaluated costs for the set-up for a database system, which ranged from commercially available options to customized systems. Because there are commercial systems currently available that allow owners and operators to maintain records in compliance with the standards, we did not find it appropriate to apply customized system costs to determine an average or range of costs. Therefore, our initial database set-up fee is estimated as $18,607 for 22 well sites and seven gathering and boosting compressor stations. In addition to this initial set-up fee, we recognize that there are annual licensing fees that include technical support and updates to software. Therefore, we have incorporated an ongoing annual fee of approximately $470. Finally, there is recordkeeping associated with tracking observed fugitive emissions and repairs, such as scheduling repairs and quality control of the data. Based on information provided by commenters,[42] we estimate additional recordkeeping costs at $430 for well sites and $860 for gathering and boosting compressor stations.

Finally, we evaluated the current estimate for reporting costs associated with the 2016 NSPS subpart OOOOa. One commenter asserted they spent over 500 hours reporting information through the Compliance and Emissions Data Reporting Interface (CEDRI) for their sources.[43] We examined the information reported to CEDRI for this commenter and concluded they have reported information for approximately 100 well sites, which would equate to 5 hours per site. This is comparable to our estimate of 4 hours per well site; therefore, we did not update the cost estimate for reporting associated with the 2016 NSPS subpart OOOOa.

In summary, we updated the cost burden estimates for recordkeeping based on the 2016 NSPS subpart OOOOa. As updated, the annualized recordkeeping and reporting costs for the existing rule, on a per site basis, are approximately $1,500 per well site and $2,500 per gathering and boosting compressor station. These costs represent the baseline from which any changes to the cost burden for reporting and recordkeeping requirements in this final rule are compared. It is important to note that while these costs represent the costs for each individual site, the EPA estimates that currently there are over 40,000 well sites and 1,250 compressor stations currently subject to the fugitive emissions requirements in the 2016 NSPS subpart OOOOa. When multiplied, the total annualized costs to the industry is estimated to exceed $60 million per year.

After updating the recordkeeping and reporting costs for the existing requirements, we evaluated requests by commenters recommending specific changes to those requirements. Several commenters requested removal of or amendments to specific line items. These included items such as the site map and observation path requirement in the monitoring plan, records related to the date and repair method for each repair attempt, and name of the operator performing the survey. After further review of the specific requirements, for the reasons explained below, we agree with the commenters that some of the items are not critical or are redundant for demonstrating compliance and, therefore, are an unnecessary burden.

We are amending the monitoring plan by removing the requirement for a site map and observation path when OGI is used to perform fugitive emissions surveys. This requirement was in place to ensure that all fugitive emissions components could and would be imaged during each survey. As explained in the TSD,[44] we agree with the commenters that a site map and observation path are only one way to ensure all components are imaged. We are replacing the specified site map and observation path with a requirement to include procedures to ensure that all fugitive emissions components are monitored during each survey in the monitoring plan. These procedures may include a site map and observation path, an inventory, or narrative of the location of each fugitive emissions component, but may also include other procedures not listed here. These company-defined procedures are consistent with other requirements for procedures in the monitoring plan, such as the requirement for procedures for determining the maximum viewing distance and maintaining this viewing distance during a survey. As previously stated, we had not accurately accounted for the ongoing cost of updating the site map and observation path as changes

[41] See TSD at Docket ID No. EPA–HQ–OAR–2017–0483.

[42] See Re: Docket ID No. EPA–HQ–OAR–2017–0483; EPA's ''Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Reconsideration; Proposed Rule''; 83 FR 52056 (October 15, 2018). Dated May 22, 2019, located at Docket ID No. EPA–HQ–OAR–2017–0483. See memorandum for May 1, 2019 meeting with GPA Midstream located at Docket ID No. EPA–HQ–OAR–2017–0483.

[43] See Docket ID Item No. EPA–HQ–OAR–2017–0483–0757.

[44] See TSD at Docket ID No. EPA–HQ–OAR–2017–0483.

occur at the site. Based on information provided by one commenter, we estimate this amendment will save each site $580 with the semiannual monitoring frequency. These cost reductions are based on an initial cost of $400 to develop the site map and observation path, plus $180 to update the site map or observation path each year, based on a semiannual monitoring frequency.

We are not finalizing the proposed recordkeeping requirement to keep records of each repair attempt. Instead, the final rule requires maintaining a record only for the first attempt at repair and the completion of repair. Other interim repair attempts are not necessary for demonstrating compliance with the repair requirements. Additionally, we are removing the requirement to maintain records of the number and type of components not repaired during the monitoring survey. The 2016 NSPS subpart OOOOa required maintaining a record of the number and type of components found with fugitive emissions that were not repaired during the monitoring survey. After further review, this information can be derived from, and is, therefore, redundant to, other records of the survey date and repair dates required for all fugitive emissions components. While it is difficult to quantify the reduction in cost burden of the removal of these records, we have estimated a reduction in cost of 25 percent, or $107 per site per year as discussed in the TSD.

We are also amending the reporting requirements to streamline reporting based on comments received and further reconsideration of what information is essential to demonstrate compliance with the standards. First, as we are finalizing the electronic reporting form for the annual report required by 40 CFR 60.5420a(b) concurrently with this action, we are updating the CEDRI reporting template to reflect the streamlined reporting requirements in this final action and ease review of the information contained within the form. Specifically, for reporting compliance with the fugitive emissions requirements, we have created dropdown menus for the operator to select the type of site for which they are reporting (*i.e.,* well site or compressor station), to indicate whether the well site changed status to a wellhead-only well site during the reporting period, and identify any approved alternative fugitive emissions standard that was used during the reporting period for the site. Second, we are removing specific items from the annual report as listed in section IV.I.3 of this preamble. We are removing the requirement to report the name or unique ID of the operator performing the survey; however, this information must be maintained in the record, similar to the LDAR requirements for onshore natural gas processing plants. We are removing the requirement to report the number and type of difficult-to-monitor and unsafe-to-monitor components that were monitored during the specified survey. This information is required to be kept in the record, and the type and number of these components would already be included in the reported number and type of components found with fugitive emissions during the survey. The date of successful repair is being removed from the report because we already require owners and operators to report the number and type of fugitive emissions not repaired on time. The date of successful repair will be maintained in the record. Finally, the type of instrument used for the resurvey is being removed from the report because the rule allows either OGI or Method 21 (analyzer or a soap bubbles test). The information is required to be kept in the record. Similar to the recordkeeping changes identified in the previous paragraph, it is difficult to estimate the reduced cost burden of each of these individual items. That said, as shown in the TSD, we have estimated a burden reduction of 25 percent, or $61 per site per annual report.

In summary, the amendments to the recordkeeping and reporting requirements in this final rule will reduce the recordkeeping and reporting burden for NSPS subpart OOOOa. The estimated annualized recordkeeping and reporting costs for this final rule, on a per site basis, are approximately $1,100 per well site and $1,750 per gathering and boosting compressor station. This results in an annualized burden reduction of approximately 27 percent for well sites and 30 percent for gathering and boosting compressor stations.[45]

3. Additional Updates to the Model Plants

We also received information from commenters that suggested additional updates beyond those already discussed above. These included the major equipment counts and survey costs. A detailed discussion of these updates, which we agree are necessary, is provided in the TSD.[46] A summary of these updates is provided below.

Well sites. In the October 15, 2018, proposal, we maintained the assumed flat contractor fee of $600 per survey. However, information from commenters suggested this may be an overestimate of survey costs if an hourly rate were used. To examine this comment, we analyzed the CEDRI reports, and evaluated the survey times that were reported. Based on this information, we estimated it takes operators 3.4 hours to complete a survey at a well site, including the travel time to and from the well site. This is based on an average survey time of approximately 1.4 hours. The travel time considers travel between sites and the shared travel of mobilizing a monitoring operator. We applied an hourly rate of $134 based on the Regulatory Analysis performed by the Colorado Department of Public Health and Environment in support of Colorado's Regulation 7.[47] We believe this more accurately reflects the costs of performing the survey than the previously assumed flat rate of $600.

Low production well sites. The low production well site model plants (*i.e.,* well sites with total production at or below 15 boe per day) were updated after further review of the Fort Worth Study, updates to the Greenhouse Gas Inventory (GHGI), and based on comments received. First, the counts of wellheads, separators, meters/piping, and dehydrators were recalculated after removing well sites that listed no production on the day prior to emissions measurements during the Fort Worth Study. This resulted in a decrease in the number of separators and meters/piping for the low production gas well pad. The scaling factors were also updated based on these revisions and applied to low production oil well pads and low production associated gas well pads. Further discussion on these changes are in the TSD. Like the well sites discussed above, we maintained the estimate of one controlled storage vessel per low production well site. One commenter provided some preliminary information regarding component counts, specific to valves and storage vessels, but also stated in their comments that the information was not representative.[48] Therefore, as discussed in the TSD, it was not appropriate to revise the model plants using information this commenter provided. We also

[45] See TSD for additional information on the estimated cost burden at the individual site level at Docket ID No. EPA–HQ–OAR–2017–0483.

[46] See TSD at Docket ID No. EPA–HQ–OAR–2017–0483.

[47] Colorado Department of Public Health and Environment, ''Regulatory Analysis for Proposed Revisions to Colorado Air Quality Control Commission Regulation Numbers 3, 6, and 7'' (5 CCR 1001–5, 5 CCR 1001–8, and CCR 1001–9), February 2014.

[48] See Docket ID Item No. EPA–HQ–OAR–2017–0483–1006.

performed an analysis of the survey time and found that on average, the surveys for low production well sites were approximately 30 minutes. After accounting for travel time, we estimate that each survey of a low production well site takes 2.4 hours. We applied the same hourly rate of $134 to estimate the total cost of each survey.

Gathering and boosting compressor stations. Information of average equipment counts were provided by GPA Midstream for gathering and boosting compressor stations.[49] We updated the model plant estimate to use this information. Specifically, we revised the estimated number of separators from 11 to five, meter/piping from seven to six, gathering compressors from five to three, in-line heaters from seven to one, and dehydrators from five to one, which reduces the baseline emissions estimated for the compressor station. We maintained the cost for the survey of $2,300 because the commenter indicated this was appropriate based on implementation of the rule.

4. Cost Effectiveness of Fugitive Emissions Requirements

With the revisions discussed in sections V.B.1 through 3 of this preamble incorporated in the model plants, we reexamined the costs and emission reductions for various monitoring frequencies to determine the updated costs of control. In evaluating the costs for this final rule, we also reexamined the decisions made in the 2016 NSPS subpart OOOOa for comparison. In the 2016 NSPS subpart OOOOa, we evaluated the controls under different approaches, namely a single pollutant approach and multipollutant approach.[50] Further, we stated that a frequency is considered cost effective if the cost of control for any one scenario of methane (without consideration of VOC), VOC (without consideration of methane), or the combination of both pollutants is cost effective.[51] That is, if the cost of control for reducing VOC, where all costs are attributed to VOC control and zero to methane control, is cost effective, then that frequency is cost effective regardless of the methane-only or multipollutant costs.

In the Review Rule, finalized in the **Federal Register** of Monday, September 14, 2020, we are rescinding the methane standards for NSPS subpart OOOOa. Therefore, in this final rule, we examined the cost effectiveness for the control of VOC emissions only. For each frequency evaluated in this final rule, we examined the total cost effectiveness of each monitoring frequency (*i.e.,* the cost of control for each frequency from a baseline of no monitoring). This is consistent with how costs were examined in the 2016 NSPS subpart OOOOa. For the reason explained in the preamble to the October 15, 2018, proposal, in addition to evaluating the total cost effectiveness of the different monitoring frequencies, this final rule also considers incremental cost (*i.e.,* the additional cost to achieve the next increment of emission reduction) to be an appropriate tool for assessing the effects of different stringency levels of control costs.[52] 83 FR 52070. It is important to note that the 2016 NSPS subpart OOOOa analysis did not present the incremental costs between each of the monitoring frequencies evaluated. The TSD supporting this final rule presents the cost of control for annual, semiannual, and quarterly monitoring frequencies for well sites producing greater than 15 boe per day and compressor stations, and biennial, annual, and semiannual monitoring frequencies for low production well sites.

When examining the costs of each monitoring frequency, we recognized that a significant percentage of the costs are independent of the monitoring frequency. That is, when annualized, the recordkeeping and reporting costs remain unchanged as monitoring frequencies increase. For example, the annualized cost of semiannual monitoring is approximately 20 percent higher than the annualized cost of annual monitoring at well sites. However, the cost effectiveness of the annual monitoring is a higher $/ton reduced because semiannual monitoring results in approximately 50 percent more emissions reductions than annual monitoring. Therefore, while more frequent monitoring does increase the costs of surveys for the year, the bulk of the costs are realized regardless of monitoring frequency. In other words, whereas we assumed during the proposal that reduced monitoring frequencies would lead to large cost savings, the analyses we performed for this final rule demonstrate that monitoring frequency is not the most significant factor in the overall cost of the fugitive emissions requirements. Below we present the costs of control for the monitoring frequencies at the model plants for well sites, low production well sites, and compressor stations.

Table 3 presents the costs of control for VOC emissions at the monitoring frequencies evaluated in this final rule and compares those costs to the costs presented for the 2016 NSPS subpart OOOOa. With the updates to the model plants discussed in section V.B.1 through 3 of this preamble, the EPA estimates that the semiannual monitoring currently required by the 2016 NSPS subpart OOOOa for well sites has a cost-effectiveness value of $4,324/ton of VOC emissions reduced. This value is $1,135/ton less than was estimated for semiannual monitoring in 2016, after adjusting for inflation. Therefore, we have determined that semiannual monitoring remains cost effective for well sites producing greater than 15 boe per day. We also considered the incremental cost effectiveness of semiannual monitoring compared to annual monitoring. This analysis showed that it cost $2,666/ton of additional VOC emissions reduced between the annual and semiannual monitoring frequencies. This cost is very reasonable and, therefore, further supports retaining semiannual monitoring. Finally, the EPA notes that, while we did not propose or take comment on quarterly monitoring for well sites, this monitoring frequency results in a total cost of control of $4,725/ton of VOC emissions reduced, which is also less than the inflation-adjusted cost-effectiveness value for quarterly monitoring that was calculated in 2016. However, the incremental cost to reduce additional emissions by going from semiannual monitoring to quarterly monitoring is $5,927/ton, which is a value that is higher than the EPA has previously found to be cost effective in the past.[53]

[49] See Docket Item ID No. EPA–HQ–OAR–2017–0483–1261.

[50] See 80 FR 56616. Under the single pollutant approach, we assign all costs to the reduction of one pollutant and zero costs for all other pollutants simultaneously reduced. Under the multipollutant approach, we allocate the annualized costs across the pollutant reductions addressed by the control option in proportion to the relative percentage reduction of each pollutant controlled. For purposes of the multipollutant approach, we assume that emissions of methane and VOC are controlled at the same time, therefore, half of the cost is apportioned to the methane emission reductions and half of the cost is apportioned to VOC emission reductions. In this evaluation, we examined both approaches across the range of identified monitoring frequencies, annual, semiannual, and quarterly.

[51] See 80 FR 56617.

[52] See also, ''Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemical Manufacturing Industry (SOCMI); Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries''; 72 FR 64860, 64864 (''2007 NSPS subparts VV and VVa'') (in its BSER analysis, the EPA evaluated the additional cost and emission reduction from lowering the leak definition for valves and determined that the additional emission reduction for SOCMI, at $5,700/ton of VOC, is not cost effective.)

[53] See 2007 NSPS subparts VV and VVa, 72 FR 64864, cited in the 2016 NSPS subpart OOOOa final rule, 80 FR 56636. See TSD for additional analysis

TABLE 3—COST-EFFECTIVENESS OF CONTROL FOR WELL SITES SUBJECT TO FUGITIVE EMISSIONS STANDARDS UNDER SUBPART OOOOA OF 40 CFR PART 60

Monitoring frequency	Cost effectiveness ($/ton VOC)		
	2016 TSD total cost effectiveness [1]	2020 TSD total cost effectiveness [2]	2020 TSD incremental cost effectiveness
Annual	$4,723	$5,153	
Semiannual	5,459	4,324	2,666
Quarterly	7,559	4,725	5,927

[1] Values from the 2016 TSD have been adjusted for inflation for comparison purposes.
[2] As discussed in section V.B of this preamble, the EPA received comments that our original 2016 estimates were low, especially for recordkeeping and reporting burden. The 2020 estimates include adjustments to the 2016 estimates based on this information (which is higher than the 2016 TSD) plus include streamlined recordkeeping and reporting as well as other updates. In addition, the revised analysis found that the majority of the costs of the fugitive requirements are annual costs and do not vary with the monitoring frequency. That is, the recordkeeping and reporting burden remain consistent regardless of the monitoring frequency and the cost of each survey is not directly proportional to the incremental emissions reductions achieved at more frequent surveys. This is further explained in section V.B.2 of this preamble. Hence, Table 3 shows an increase in cost effectiveness for the annual monitoring frequency, but a decrease in the cost effectiveness for the semiannual and quarterly cost effectiveness from the 2020 TSD. In contrast, the 2016 values presented here are directly from the 2016 TSD and have not been adjusted based on our new analysis of what the 2016 rule cost.

As shown in the EPA's revised model plant analysis in the TSD for this final rule, and consistent with the October 15, 2018, proposal, there is sufficient evidence that low production well sites are different than well sites with higher production and, therefore, warrant a separate evaluation of the cost of control. The EPA did not include a separate analysis of low production well sites in the 2016 NSPS subpart OOOOa. Therefore, all costs presented above for well sites from the 2016 analysis also would apply to low production well sites. The EPA proposed biennial monitoring of low production well sites (*i.e.,* well sites with total production at or below 15 boe per day). Based on the revised cost analysis, the EPA estimates that the proposed biennial monitoring frequency has a cost effectiveness of $6,061/ton of VOC emissions reduced. In addition, we estimate that annual monitoring would cost $7,577/ton VOC, and semiannual monitoring currently required by the 2016 NSPS subpart OOOOa has a cost of $6,116/ton of VOC emissions reduced. All of these values are higher than the inflation-adjusted value of $5,459/ton VOC that was estimated for semiannual monitoring at well sites in 2016. Further, all of these costs are higher than a value the EPA has previously stated is not cost effective.[54] Therefore, we have determined that none of the monitoring frequencies are cost effective for low production well sites. Table 4 provides a summary of the costs of control for low production well sites.

TABLE 4—COST-EFFECTIVENESS OF CONTROL FOR LOW PRODUCTION WELL SITES SUBJECT TO FUGITIVE EMISSIONS STANDARDS UNDER SUBPART OOOOA OF 40 CFR PART 60

Monitoring frequency	Cost effectiveness ($/ton VOC)		
	2016 TSD total cost effectiveness [1]	2020 TSD total cost effectiveness [2]	2020 TSD incremental cost effectiveness
Biennial [3]	N/A	$6,061	
Annual	$4,723	7,577	$12,125
Semiannual	5,459	6,116	3,192

[1] Values from the 2016 TSD have been adjusted for inflation for comparison purposes.
[2] As discussed in section V.B of this preamble, the EPA received comments that our original 2016 estimates were low, especially for recordkeeping and reporting burden. The 2020 estimates include adjustments to the 2016 estimates based on this information (which is higher than the 2016 TSD) plus include streamlined recordkeeping and reporting as well as other updates. In addition, the revised analysis found that the majority of the costs of the fugitive requirements are annual costs and do not vary with the monitoring frequency. That is, the recordkeeping and reporting burden remain consistent regardless of the monitoring frequency and the cost of each survey is not directly proportional to the incremental emissions reductions achieved at more frequent surveys. This is further explained in section V.B.2 of this preamble. Further, low production well site model plants were not developed as part of the 2016 rulemaking. Therefore, the 2016 values presented here were for all well sites, without consideration of production. Hence, Table 4 shows an increase in cost effectiveness for the monitoring frequencies presented. In contrast, the 2016 values presented here are directly from the 2016 TSD and have not been adjusted based on our new analysis of what the 2016 rule cost.
[3] Biennial monitoring was not evaluated in 2016, therefore, no cost effectiveness is presented in Table 4.

Further, while this final rule does not have to consider the costs of controlling methane emissions, the EPA did evaluate those costs. The costs for all of the monitoring frequencies evaluated for low production well sites are greater

and cost information, located at Docket ID No. EPA–HQ–OAR–2017–0483.

[54] See 2007 NSPS subparts VV and VVa, 72 FR 64864, cited in the 2016 NSPS subpart OOOOa final rule, 80 FR 56636. See TSD for additional analysis and cost information, located at Docket ID No. EPA–HQ–OAR–2017–0483.

and cost information, located at Docket ID No. EPA–HQ–OAR–2017–0483.

than the highest value for methane that the EPA determined to be reasonable in the 2016 NSPS subpart OOOOa for both methane only and under the multipollutant approach.[55] In the 2015 proposal for NSPS subpart OOOOa, the EPA stated that a cost of control of $738 per ton of methane reduced did not appear excessive when all costs are assigned to methane reduction and zero to VOC reduction. 80 FR 56624. Based on the revised analysis, the costs of control of methane emissions under the single pollutant approach for low production well sites are more than double this value of $738 per ton at all of the monitoring frequencies evaluated. This value is also exceeded under a multipollutant approach where methane reduction only assumes half the cost, as explained in the TSD.[56] Therefore, even if we had not rescinded the methane standards in the Review Rule, we would still conclude that fugitive emissions monitoring, at any of the frequencies evaluated, is not cost effective for low production well sites.

While we are concluding that fugitive emissions monitoring is not cost effective for low production well sites, production at these well sites could potentially increase to greater than 15 boe per day, rendering monitoring to be cost effective. For example, a new well may be drilled at a well site, or the existing wells may be refractured to increase the production levels. When these actions occur, the final rule requires a new 30-day calculation of the total well site production. If the total production remains at or below 15 boe per day, no monitoring is required as long as the owner or operator continues to maintain the production at these low levels. However, if the total production following one of these actions has increased to greater than 15 boe per day, the owner or operator must begin monitoring for fugitive emissions within 90 days of the startup of production following such action, the same as the requirement for a modified well site. Therefore, under the final rule, low production well sites remain affected facilities; however, they have the option of maintaining production at or below 15 boe per day on a continuous basis instead of implementing the fugitive monitoring requirement.

There are three timeframes in which we are requiring sources to calculate the total production from the well site. First, there are well sites that have not yet triggered the requirements in NSPS subpart OOOOa, which are those constructed, reconstructed, or modified after this final rule becomes effective. The owner or operator of such a well site has the option to calculate the total well site production based on the first 30 days of production. If the total production from all of the wells at the well site is at or below 15 boe per day (combined for both oil and natural gas produced at the site), then the owner or operator of the well site may either maintain production at or below this threshold on a rolling 12-month average or begin the fugitive emissions program. The owner or operator must comply with one of these two requirements at any and all times. If the total production of the well site is above 15 boe per day as determined in the first 30 days of production, then the site must begin the fugitive emissions program, including completing the initial monitoring within 90 days of startup of production. Recognizing that there are some well sites that have triggered the fugitive emissions requirements that may not have 12-months' worth of production data yet but are already able to demonstrate they are low production, the final rule contains a provision to allow the owner or operator to use production records based on the first 30 days of production after becoming subject to the NSPS to determine if the well site is low production. This determination must be made by December 14, 2020. After that date, the owner or operator may use the rolling 12-month average, as described next, for demonstrating the well site is low production.

Next, recognizing that production declines over time, we are also allowing an option for owners or operators subject to the monitoring requirement to determine whether the total production for the well site declines to 15 boe per day or below when calculated on a rolling 12-month average. If the total well site production is at or below this threshold on a rolling 12-month average, then the owner or operator has the option to stop fugitive monitoring and instead maintain total well site production below this threshold. The owner or operator must comply with either the fugitive monitoring requirement or maintain total well site production below this threshold at any and all times.

Finally, the EPA is aware that a low production well site could later increase production due to subsequent activities, as discussed above. For example, owners or operators commonly take actions to increase production as production declines or continue to drill new wells after the initial startup of production of the well site. If production subsequently increases to greater than 15 boe per day, it would be cost effective to implement the fugitive emissions monitoring requirement. In light of the above, the final rule requires that any well site that is not conducting fugitive emissions monitoring because total well site production is at or below the threshold must redetermine the total well site production following any of the following actions: A new well is drilled, a well is hydraulically fractured or re-fractured, a well is stimulated in any manner for the purpose of increasing production (including well workovers), or a well at the well site is shut-in for the purposes of increasing production from the well site. These well sites must recalculate the total well site production based on the first 30 days of production following the completion of that action. It is inappropriate to continue to utilize a rolling 12-month average because the production in the 11 months prior to the action that increased production would bias the average low. Like well sites constructed, reconstructed, or modified after this final rule, these well sites must recalculate the total well site production based on the first 30 days of production following the completion of that action to increase production.

We have not calculated the impacts of the production calculation because owners and operators are already required to track production for other purposes, regardless of environmental regulation, and we do not anticipate any additional burden associated with these records for purposes of this rule.

The final rule also requires semiannual monitoring of gathering and boosting compressor stations. As with fugitive monitoring of well sites, based on the revised cost analysis in the TSD for the final rule, the EPA reexamined the costs and emission reductions, including incremental cost and emission reductions, for various monitoring frequencies. In the October 15, 2018, proposed rulemaking, the EPA co-proposed annual and semiannual monitoring of fugitive emissions at all compressor stations. As previously discussed, the 2016 NSPS subpart OOOOa requires quarterly monitoring for compressor stations, including gathering and boosting stations, transmission stations, and storage stations. Therefore, the 2016 determination that quarterly monitoring was cost effective was based on the

[55] See Section 2.5.1.1 of the TSD for additional information.

[56] For the multipollutant approach, the emissions of each pollutant are calculated based on the relative percentage of each pollutant in the gas emitted. Since the same control is applied to the gas emitted, the cost is divided in half to attribute the costs of control equally between the two pollutants (methane and VOC).

weighted average of the cost-effectiveness values for all of those station types. In the Review Rule, which was finalized in the **Federal Register** of Monday, September 14, 2020, the EPA has removed the transmission and storage segments from the Crude Oil and Natural Gas Production source category and rescinded the standards for those sources. As a consequence, only gathering and boosting compressor stations remain subject to the standards of NSPS subpart OOOOa.

After updating the compressor station model plants, the EPA estimates that the quarterly monitoring currently required by the 2016 NSPS subpart OOOOa has a cost effectiveness of $3,221/ton of VOC emissions reduced at gathering and boosting compressor stations. The EPA also considered the incremental cost effectiveness of going from semiannual monitoring to quarterly monitoring. This analysis showed that it cost $4,988/ton of additional VOC emissions reduced between the semiannual and quarterly monitoring frequencies. These values (total and incremental) are considered cost-effective for VOC reduction based on past EPA decisions, including the 2016 rulemaking. However, the incremental cost of $4,988/ton of additional VOC reduced is on the high end of the range that we had previously found to be cost-effective for VOC.[57] In contrast, semiannual monitoring is very cost-effective, at a total cost of $2,632/ton and incremental cost of $2,501/ton between annual and semiannual monitoring to reduce an additional 2,156 tons of VOC per year.[58] We further note that moving from annual to semiannual monitoring achieves the same incremental reduction in VOC emissions as moving from semiannual to quarterly monitoring (2,156 tons/year) but at half the cost per ton of additional VOC reduced ($2,501/ton instead of $4,988/ton). Moreover, additional factors influence our evaluation of the appropriateness of selecting quarterly monitoring as compared to semiannual monitoring for compressor stations. In particular, the oil and gas industry is currently experiencing significant financial hardship that may weigh against the appropriateness of imposing the additional costs associated with more frequent monitoring.[59] The EPA also acknowledges that there are potential efficiencies, and potential cost savings, with applying the same monitoring frequencies for well sites and compressor stations,[60] In light of all of these considerations, the EPA thinks it is reasonable to forgo quarterly monitoring and choose semiannual monitoring as the BSER for compressor stations. Table 5 provides a summary and comparison of these costs per ton of VOC reduced.

While this final rule does not have to consider the cost-effectiveness of controlling methane emissions, the EPA did evaluate those costs per ton of methane reduced. As discussed above for low production well sites, the highest costs per ton of methane reduced that we have found to be cost-effective in the past is $738/ton. Assigning all costs to methane (under the single pollutant approach) results in a total cost per ton of $895/ton and incremental cost per ton of $1,387/ton of methane reduced for quarterly monitoring, which almost doubles the highest cost per ton of methane reduced that we had previously found to be cost-effective ($738/ton). Under the multipollutant approach, the incremental cost per ton of additional methane reduced is $695/ton. While this incremental cost per ton is cost-effective, it is also at the high end of the range. Therefore, based on these costs per ton of methane reduced and considering the current financial hardships being experienced across the oil and gas industry, we would have similarly required semiannual monitoring even if methane had remained a regulated pollutant.

TABLE 5—COST-EFFECTIVENESS OF CONTROL FOR COMPRESSOR STATIONS SUBJECT TO FUGITIVE EMISSIONS STANDARDS UNDER SUBPART OOOOA OF 40 CFR PART 60

Monitoring frequency	Cost effectiveness ($/ton VOC)					
	Gathering and boosting stations			Compressor station weighted-average		
	2016 TSD total cost effectiveness [1]	2020 TSD total cost effectiveness [2]	2020 TSD incremental cost effectiveness	2016 TSD total cost effectiveness [1]	2020 TSD total cost effectiveness	2020 TSD incremental cost effectiveness
Annual	$2,105	$2,698		$3,278	$3,606	
Semiannual	2,443	2,632	$2,501	3,682	3,341	$2,811
Quarterly	3,391	3,221	4,988	5,006	3,908	5,607

[1] Values from the 2016 TSD have been adjusted for inflation for comparison purposes.

[2] As discussed in section V.B of this preamble, the EPA received comments that our original 2016 estimates were low, especially for recordkeeping and reporting burden. The 2020 estimates include adjustments to the 2016 estimates based on this information (which is higher than the 2016 TSD) plus include streamlined recordkeeping and reporting as well as other updates. In addition, the revised analysis found that the majority of the costs of the fugitive requirements are annual costs and do not vary with the monitoring frequency. That is, the recordkeeping and reporting burden remain consistent regardless of the monitoring frequency and the cost of each survey is not directly proportional to the incremental emissions reductions achieved at more frequent surveys. This is further explained in section V.B.2 of this preamble. Hence, Table 5 shows an increase in cost effectiveness for the annual and semiannual monitoring frequencies, but a decrease in the cost effectiveness for the quarterly cost effectiveness from the 2020 TSD. In contrast, the 2016 values presented here are directly from the 2016 TSD and have not been adjusted based on our new analysis of what the 2016 rule cost.

C. AMEL

The 2016 NSPS subpart OOOOa contains provisions for requesting an AMEL for specific work practice standards covering well completions, reciprocating compressors, and the collection of fugitive emissions components at well sites and compressor stations. While written with emerging technologies as the focus, the provisions in the 2016 NSPS subpart

[57] See 2007 NSPS subparts VV and VVa, 72 FR 64864, cited in the 2016 NSPS subpart OOOOa final rule, 80 FR 56636. See TSD for additional analysis and cost information, located at Docket ID No. EPA–HQ–OAR–2017–0483.

[58] See Table 2–35f of the TSD located at Docket ID No. EPA–HQ–OAR–2017–0483.

[59] See Iyke, B. N., 2020. ''COVID–19: The reaction of US oil and gas producers to the pandemic.'' Energy RESEARCH LETTERS, 1(2), located at *https://erl.scholasticahq.com/article/13912.pdf.*

See Gil-Alana, L. A., & Monge, M., 2020. ''Crude Oil Prices and COVID–19: Persistence of the Shock.'' Energy RESEARCH LETTERS, 1(1), located at *https://doi.org/10.46557/001c.13200.*

See Sharif, et al., 2020. ''COVID–19 pandemic, oil prices, stock market, geopolitical risk and policy uncertainty nexus in the US economy: Fresh evidence from the wavelet-based approach.'' International Review of Financial Analysis, 70, 7101496, located at *https://doi.org/10.1016/j.irfa.2020.101496.*

[60] See Docket ID Nos. EPA–HQ–OAR–2017–0483–0755 and EPA–HQ–OAR–2017–0483–0773.

OOOOa could also be used for state programs, though the application requirements were unclear on certain points. Therefore, the EPA proposed amendments to the application requirements as they relate to emerging technologies in order to streamline the application process, and proposed a new section to address state programs, including proposed alternative fugitive emissions standards based on our review of existing state programs. This section describes changes, based on information provided in public comments, to the AMEL provisions.

1. Emerging Technologies

The EPA continues to recognize that new technologies are expected to enter the market soon that could locate sources of fugitive emissions sooner and at lower costs than the current technologies required by the 2016 NSPS subpart OOOOa. While the EPA established a foundation for approving the use of these emerging technologies in the 2016 NSPS subpart OOOOa, we proposed specific revisions in the October 15, 2018, proposal to help streamline the application requirements and process. Specifically, we proposed to allow owners and operators to apply for an AMEL on their own, or in conjunction with manufacturers or vendors and trade associations. We also proposed to allow the use of test data, modeling analyses, and other documentation to support field test data, provided seasonal variations are accounted for in the analyses. While we received many supportive comments on these specific proposed amendments, we also received comments asserting that the application process is still too restrictive and burdensome to promote innovation.

First, the commenters stated that applications seeking approval of an alternative should be accepted by the EPA from manufacturers and vendors independently of owners and operators. We have reviewed the information provided by the commenters and agree that it is appropriate in the context of the revisions to 40 CFR 60.5398a to remove language that previously indicated from whom the Administrator would consider applications under that section because section 111(h)(3) of the CAA states ''any person'' can request an AMEL, and if they establish to the satisfaction of the Administrator that the AMEL will achieve emission reductions that are at least equivalent with the requirements of the rule, then the Administrator will allow the alternative. While the final rule allows any person to submit an application for an AMEL under this provision, the final rule still includes the minimum information that must be included in each application in order for the EPA to make a determination of equivalency and, thus, be able to approve an alternative. This final rule requires applications for these AMEL to include site-specific information to demonstrate equivalent emissions reductions, as well as site-specific procedures for ensuring continuous compliance.

Next, the commenters generally supported the proposal to allow the use of test data, modeling analyses, and other documentation to support field test data. In addition to their support of these supplemental data, commenters also requested that the final rule allow the use of information collected during testing at controlled testing facilities to be considered in lieu of site-specific field testing. The EPA considered whether it would be appropriate to allow this information and has concerns related to the representativeness of the information when compared to actual operating sites. For example, we are aware of one controlled testing facility located in the U.S., the Methane Emissions Technology Evaluation Center (METEC) located in Fort Collins, Colorado.[61] That facility is equipped with several different configurations of well pads using equipment that was donated from the oil and natural gas industry. The test well pads do not produce or process field gas; in fact, none of the equipment that is onsite is in contact with field gas. Instead, METEC utilizes compressed natural gas that is transported from offsite in order to create controlled leaks. In establishing controlled leaks, METEC uses tubing with leak points near typical leak interfaces to simulate a leak; however, these releases are not operated at pressures or temperatures that are typically encountered at an operating well site in the field. While we agree that testing at a controlled testing facility such as the METEC site can be helpful to understanding how a technology may perform, and the information gathered from such controlled test sites can be useful in supplementing other data, it is inappropriate to rely solely on the information collected at these types of facilities as being representative of how the technology would perform at an operating well site or compressor station. At this time, the EPA does not believe that it can determine the efficacy of a monitoring or detection technology where demonstrations take place only under controlled conditions. By extension, the EPA would be unable to determine the validity of whether an alternative indeed achieves equivalent emissions reductions if only presented with data from testing at a controlled testing facility. Therefore, we are finalizing amendments that require field test data, but that allow the use of test data, modeling analyses, data collected at controlled testing facilities, and other documentation to support and supplement field test data.

Next, we solicited comment on whether groups of sites within a specific area that are operated by the same operator could be grouped under a single AMEL. We received comments that discussed this broad application of alternatives in two distinct ways: (1) Allowing the aggregation of emission sources beyond the individual site in order to demonstrate equivalent emission reductions, and (2) allowing the use of approved AMELs at future sites that are designed and operated under the conditions specified in the approved AMEL. We evaluated both types of broad approval options raised in the comments by considering the definitions in the existing rule and the AMEL provisions of section 111(h)(3) of the CAA.

In the first instance, we evaluated whether it would be appropriate to allow the aggregation of emission sources beyond the individual site when evaluating the equivalency of an alternative. Specifically, we considered whether an applicant for an AMEL related to fugitive emissions monitoring could aggregate the total fugitive emissions across multiple sites within a specific geographic area, such as a basin, in order to demonstrate the requested AMEL would achieve at least equivalent emission reductions as the NSPS requirements for fugitive emissions monitoring and repair at an individual site. The work practice standards for the collection of fugitive emissions components at a well site or at a compressor station were established pursuant to section 111(h) of the CAA, which allows an opportunity for an AMEL. In accordance with section 111(h)(3) of the CAA, a source may use an approved AMEL for purposes of compliance with the established work practice. The commenters stated that the generic use of the word ''source'' allows aggregation of fugitive emissions components amongst multiple sites and is not limited to single sites. The EPA does not agree that aggregating fugitive emissions across multiple sites is a viable method to determine equivalency with the NSPS provided the definitions of affected facility in NSPS subpart OOOOa related to the collection of

[61] See *https://energy.colostate.edu/metec* for more information on the METEC facility.

fugitive emissions components. NSPS subpart OOOOa defines the ''source'' that is subject to the work practice standards for fugitive emissions as the ''collection of fugitive emissions components at a well site'' and the ''collection of fugitive emissions components at a compressor station'' in 40 CFR 60.5365a(i) and (j). These terms specify single-site applicability for the work practice standard. Because the rule does not define an affected facility or a source to be a geographic area, such as a basin, it is the EPA's determination that a demonstration of equivalent emission reductions for purposes of evaluating alternatives to the BSER has been based on the fugitive emissions at a single site, and not an aggregation of emissions across multiple well sites, compressor stations, or a combination of these two site types with an averaging or trading program akin to what the EPA has referred to in the past as a ''bubble'' approach. For further discussion on this topic, see section VI.C.2 of this preamble.

The second point raised by commenters was that requiring site-specific approvals (*i.e.,* AMELs that list specific well sites or compressor stations) would result in unnecessary burden as new sites with the same owner or operator, similar equipment, operating conditions, and in the same geographic area (*e.g.,* basin) are constructed. According to commenters, this unnecessary burden results from the need for the owner or operator to apply for an AMEL for each of these sites in the future, even though the AMEL would be identical to the previously approved AMELs for similar sites. We agree with the commenters that it is possible that AMELs could, where appropriate, be approved for future use at sites not included in the original application as discussed below. Commenters also encouraged the EPA to consider the potential for AMELs applicable to specific types of facilities with different owners or operators within an industry category or geographic region.

While the EPA is not amending 40 CFR 60.5398a at this time to address broad approvals of AMEL applications, we do recognize that the Agency has discretion in certain circumstances to allow for broad approval of alternatives via several different paths. First, for example, an applicant could submit an AMEL application for an alternative technology (and associated work practice) that includes specific site characteristics under which the technology (and associated work practice) has been tested and that demonstrates equivalent reductions to the standards in the NSPS. The application would include an explanation of these characteristics (*e.g.,* characteristics of the formation, operating conditions at the site, type of equipment and processes located at the site, and variables that affect performance of the technology or work practice) and a request that the EPA consider broad approval of the application such that sites (including those subject to the NSPS at the time of application and future sites) that meet the same characteristics could utilize the same approved alternative without the need for additional application to the EPA. The scope of such an approval might be limited based on any number of conditions as appropriate (such as those mentioned above). The EPA believes that, depending on the facts of the application, some type of broad approval may be a feasible path forward, but we will need to evaluate the information specific to the application in hand once received. As of the date of this final rule, the EPA has received no applications for AMELs to be able to determine if additional amendments (beyond those in this final rule) are necessary for such a situation, and how such potential amendments might be drafted to facilitate such broad approvals. In summary, if the applicant believes that it is appropriate to apply the alternative to more sites than those listed in the application because the proposed alternative can achieve equivalency for other sites, then the applicant should state this intent and make this demonstration to the EPA within the application. If provided with sufficient information, explanation, justification, and documentation, the EPA may determine under what defined conditions, if any, it is appropriate to allow the use of the alternative once approved at any site meeting those conditions, including sites constructed in the future.

Second, the EPA is interested in developing a framework in the future for AMEL requests that share similar characteristics (*e.g.,* technologies) in order to streamline both applications and approvals. While the EPA has not received applications related to the work practice standards in the 2016 NSPS subpart OOOOa, we have evaluated and approved AMELs for other sources in a few instances for one specific control technology, pressure assisted multi-point flares (for further information, see the EPA rulemaking Docket ID No. EPA–HQ–OAR–2014–0783). In the course of reviewing those applications, the EPA was able to establish testing criteria for this particular control technology to demonstrate equivalency with the underlying operational standards (*i.e.,* 98-percent control efficiency) as well as other certain design, equipment, and work practice standards, which, if met, would help streamline approval of applications submitted after that point. The EPA is committed to working with stakeholders to develop testing criteria for technologies and work practices for NSPS subpart OOOOa. However, due to the variability of this sector, as well as the wide-ranging array of technologies currently being pursued for development, we are unable to amend the language within this rule and provide such a framework at this time. For the pressure assisted multi-point flares, the EPA developed the testing framework in conjunction with an application and with stakeholder feedback from the first AMEL requests received and approved for that particular technology. We have not yet reached that critical first step of an application being submitted to the EPA to determine what testing framework might be appropriate, or how that framework might be technology family-specific (*e.g.,* continuous point monitors, aerial surveys, mobile equipment). We encourage interested stakeholders to continue engaging with us early in any application process so additional streamlining measures can be evaluated. The EPA is committed to improving this process of evaluating emerging technologies and may publish another request for information regarding technology innovation and the application process.

Third, if an applicant can demonstrate that a technology has very broad applicability across the entire industry, then, in addition to exploring the possibility of an AMEL, the EPA also would consider whether to undertake a rulemaking process to amend NSPS subpart OOOOa to allow for widespread use of the technology. As always, the EPA will review each application individually to determine if it has demonstrated that the alternative will achieve equivalent or greater emission reductions than the work practice standard the alternative would replace.

In summary, we are finalizing amendments to the application requirements for an AMEL in 40 CFR 60.5398a. We are allowing applications from any person. Further, we are allowing the use of supplemental data, such as test data, data collected at controlled testing facilities, modeling analyses, and other relevant documentation, to support field data that are collected to demonstrate the emissions reductions achieved. While we are not amending the rule to specifically state an approved AMEL can be used for future sources, we recognize that it may be possible, where appropriate, for the EPA to establish specific conditions during the AMEL process under which an approved alternative may be applied at sites not specifically listed in the application.

2. State Fugitive Emissions Programs

To reduce duplicative burdens to the industry related to the fugitive emissions requirements, the EPA proposed alternative fugitive emissions standards for well sites and compressor stations located in specific states. These alternative standards were proposed based on the EPA's review of the monitoring and repair requirements of the individual state fugitive emissions requirements [62] relevant to well sites and compressor stations. In the proposal, we stated that a well site or compressor station, located in the specified state, could elect to comply with the specified state program as an alternative to the monitoring, repair, and recordkeeping requirements in the NSPS. However, these sites would be required to monitor all fugitive emissions components, as defined in the NSPS, comply with the requirement to develop a monitoring plan, and report the information required by the NSPS because the sites remain affected facilities.

Similar to the proposed amendments for emerging technologies, we received support for the proposed amendments for state programs. However, some commenters stated that the EPA should recognize the approved state programs as wholly equivalent to the NSPS, including for all reporting and recordkeeping requirements. The commenters indicated that the EPA's equivalency determination still leaves the regulated community in certain states subject to duplicative requirements. They added that complying with two different reporting and recordkeeping schemes for the same site is very burdensome and provided no environmental benefit.

For the proposal, we evaluated 14 existing state programs to determine whether they are equivalent to the fugitive emissions requirements in 40 CFR 60.5397a. That evaluation included a qualitative comparison of the fugitive emissions components covered by the state programs, monitoring instruments, leak or fugitive emissions definitions, monitoring frequencies, repair requirements, and recordkeeping requirements to the requirements of the NSPS.[63] However, at the time of the proposal, the EPA had not evaluated the reporting requirements of the 14 individual state programs. We have completed that evaluation for this final rule for the state programs that we proposed as alternative standards and the results of that evaluation are discussed in more detail in section VI.C.2 of this preamble. We also updated the overall analysis of equivalency.[64] Through this additional evaluation, we concluded that the recordkeeping and reporting requirements of the various state programs do not need to be exactly equivalent to the requirements of the NSPS subpart OOOOa because the purpose of recordkeeping and reporting requirements is to ensure compliance with whatever standards apply. Obviously, the state programs we evaluated are not identical to the NSPS, so it stands to reason that their associated recordkeeping and reporting requirements might differ. Therefore, when evaluating the recordkeeping and reporting requirements in the individual state programs, we focused our review on the elements of those requirements that we deemed essential to a demonstration of compliance with the individual alternative standards. Sites remain subject to the NSPS, because the alternative standards are standards within the NSPS, therefore, compliance demonstrations are necessary through recordkeeping and reporting.

At a minimum, the EPA requires reports to include information that allows a demonstration of compliance for all fugitive emissions components (as defined in 40 CFR 60.5430a) at the individual site level (*i.e.,* well site or compressor station). This means the report must provide information on each individual monitoring survey conducted at each well site or compressor station adopting the alternative fugitive emissions standards. We reviewed the reports required under state law for the six states for which we are finalizing alternative fugitive emissions standards (*i.e.,* California, Colorado, Ohio, Pennsylvania, Texas, and Utah) to determine (1) if site-level information is required in the reports and (2) if the information reported demonstrates compliance through inclusion of elements such as the date of the survey, monitoring instrument used, information for each identified fugitive emission, repair information, and delayed repair information. For three of the six states (California, Ohio, and Pennsylvania) where we are finalizing alternative standards, the required state reports are site-specific and include information that will demonstrate compliance with the alternative standards. For the other three states (Colorado, Texas, and Utah), site-specific reporting is not required, or will not demonstrate compliance with the alternative standards. Therefore, the sites adopting the alternative standards for Colorado, Texas, and Utah, would need to provide the site-specific reports required in 40 CFR 60.5420a(b)(7). As discussed in detail in section V.B.2 of this preamble, the EPA is amending the recordkeeping and reporting requirements related to the fugitive emissions requirements. The result of these amendments is an annualized burden reduction of approximately 27 percent for well sites and 30 percent for gathering and boosting compressor stations, and those same burden reductions will be realized by sites in these three states.[65]

For the three states that do not require site-specific reporting, we reviewed the state's recordkeeping requirements to determine if any additional records would be necessary for reporting the required information under the NSPS. We found that for each of the three states, the records are very similar to, if not the same as, the information required under the NSPS. Given that additional records beyond those required by the state are not necessary, the EPA concludes that there is no duplicative recordkeeping burden associated with compliance with these alternative standards. This, in addition to the significant reduction in reporting burden discussed in section V.B.2 of this preamble, allows the EPA to conclude the submission of the reports required in 40 CFR 60.5420a(b)(7) presents minimal burden for sites in Colorado, Texas, and Utah.

Therefore, to summarize, the final rule requires reporting of information to demonstrate site-level compliance with the alternative fugitive emissions standards as follows:

- Where the state report includes site-specific information for each fugitive emissions survey that demonstrates compliance with the alternative

[62] Note, several states refer to the fugitive emissions standards as LDAR.

[63] See memorandum, ''Equivalency of State Fugitive Emissions Programs for Well Sites and Compressor Stations to Final Standards at 40 CFR part 60, subpart OOOOa,'' located at Docket ID No. EPA–HQ–OAR–2017–0483. January 17, 2020.

[64] See memorandum, ''Equivalency of State Fugitive Emissions Programs for Well Sites and Compressor Stations to Final Standards at 40 CFR part 60, subpart OOOOa,'' located at Docket ID No. EPA–HQ–OAR–2017–0483. January 17, 2020.

[65] See TSD for additional information on the estimated cost burden at the individual site level at Docket ID No. EPA–HQ–OAR–2017–0483.

standard, the owner or operator has the option to either (a) provide the EPA with a copy of the state report, in the format in which is it submitted to the state, based on the following order of preference: (1) As a binary file; (2) as an Extensible Markup Language (XML) schema; (3) as a searchable portable document format (PDF); or (4) as a scanned PDF of a hard copy, or (b) provide the report required by 40 CFR 60.5420a(b)(7)(i) and (ii) to the EPA in accordance with the applicable reporting procedures.

• Where the state report does not include site-specific information for each fugitive emissions survey, the owner or operator must report the information required by 40 CFR 60.5420a(b)(7)(i) and (ii) to the EPA in accordance with the procedures applicable to such a submission.

Any owner or operator has the option to complete the information required by 40 CFR 60.5420a(b)(7) in lieu of submitting a copy of the state report. As described in section IV.I of this preamble, electronic reporting through CEDRI is now required for all reports under 40 CFR 60.5420a(b). Thus, the EPA is requiring electronic submission of reports for the alternative fugitive emissions requirements, regardless of whether the state continues to allow paper copy submissions.

The EPA believes that adoption of these alternative standards will further reduce the burden of the fugitive emissions standards on the industry from this rule. No additional recordkeeping beyond that required by the alternative standard is necessary. Additional justification for the EPA's decision to adopt these state programs as alternative fugitive emission standards is provided in the memorandum [66] summarizing the EPA's review of each state program's requirements and in section VI of this preamble.

We note that one commenter expressed concern over the proposed state equivalency determinations and noted that several of the programs evaluated have specific applicability thresholds where the standards only apply to a subset of sources, whereas the NSPS applies to all new, modified, or reconstructed sources.[67] We agree that the applicability thresholds for these state programs are different from the NSPS, but we do not agree that additional regulatory text is necessary to address this concern. The regulatory thresholds included in state programs that limit or reduce monitoring and repair requirements do not affect the requirements for sources subject to the NSPS. Therefore, if a site subject to the NSPS is not also subject to the state program because of the state-specific applicability threshold, the site would still be required to comply with the requirements of the NSPS. Where appropriate, we have amended the regulatory text to clearly define the requirements of the alternative standard. More discussion of this comment and our response is provided in section VI.C.2 of this preamble.

VI. Summary of Significant Comments and Responses

This section summarizes the significant comments on the proposed amendments and our responses to those comments. Additional comments and responses are summarized in the RTC document available in the docket.

A. Major Comments Concerning Storage Vessels

The EPA received numerous comments on the proposed amendments to the definition of ''maximum average daily throughput,'' which is key in the determination of storage vessel affected facility status under the 2016 NSPS subpart OOOOa. Many of the comments we received were related to manifolded storage vessel systems. The EPA considered those comments and is finalizing changes to the rule to address a subset of these manifolded storage vessel systems (*i.e.,* controlled storage vessel batteries as described in section V.A of this preamble). A more detailed summary of the comments regarding controlled storage vessel batteries, and our responses to those comments, is available in the RTC document for this action (see Chapter 6).[68]

In addition to the comments the EPA received on controlled storage vessel batteries, we also received other comments related to storage vessel applicability determination criteria. Below is a discussion related to three of these topics: (1) The use of legally and practicably enforceable limits that maintain VOC emissions from storage vessels below 6 tpy, (2) the calculation of maximum average daily throughput based only on the days of actual production in the first 30 days, and (3) the determination of maximum average daily throughput for storage vessels at gathering and boosting compressor stations, onshore natural gas processing plants, and transmission and storage compressor stations.

Comment: Some commenters stated that the EPA proposed additional parameters on what constitutes a ''legally and practicably enforceable'' limit; and, therefore, heightened the standard for allowing use of such limit in estimating a storage vessel's potential VOC emissions for purposes of determining applicability of the storage vessel standards at 40 CFR 60.5395a. Specifically, the commenters took issue with the statement in the preamble to the October 15, 2018, proposed rulemaking where the EPA stated ''only limits that meet certain enforceability criteria may be used to restrict a source's potential to emit, and the permit or requirement must include sufficient compliance assurance terms and conditions such that the source cannot lawfully exceed the limit.'' 83 FR 52085. One commenter claimed that these additional criteria (1) conflict with prior EPA statements made during earlier oil and gas NSPS rulemakings; (2) conflict with the EPA's traditional practice of deferring to states regarding the appropriate mechanisms for limiting potential to emit (PTE); (3) raise concerns about how this new interpretation/approach would apply in the title V and New Source Review/Prevention of Significant Deterioration context where operators are relying on the same control requirements to limit their PTE; (4) raise significant concerns about retroactive application; and (5) ignore that the requirements for fugitive components under the 2016 NSPS subpart OOOOa are not tied to storage tank applicability and apply regardless of whether a storage tank is an affected facility under the rule.

Commenters also cited the EPA's ''enforceability criteria'' guidance, which was first introduced in 1995, and asserted that the EPA's proposed additional criteria were not consistent with that guidance. One commenter was concerned that the EPA's proposal not only conflicted with the Agency's traditional and consistent practice, it also threatened to subject sources to the NSPS that already determined their potential for VOC emissions was below the 6 tpy threshold by using the EPA's prior guidance.

Response: The EPA disagrees with the commenters because we did not propose additional parameters on what would constitute a legally and practicably enforceable limit. Rather, in the proposal preamble, the EPA simply summarized its position on this matter based on the existing substantial body of EPA guidance and administrative

[66] See memorandum, ''Equivalency of State Fugitive Emissions Programs for Well Sites and Compressor Stations to Final Standards at 40 CFR part 60, subpart OOOOa,'' located at Docket ID No. EPA–HQ–OAR–2017–0483. January 17, 2020.

[67] See Docket ID Item No. EPA–HQ–OAR–2017–0483–2041.

[68] See Chapter 6 of the RTC document located at Docket ID No. EPA–HQ–OAR–2017–0483.

decisions relating to potential emissions and emissions limits. As the EPA explained, limits that meet certain enforceability criteria may be used to restrict a source's potential emissions. For example, any such emission limit must be enforceable as a practical matter, which requires that the permit or requirement specifies how emissions will be measured or determined for purposes of demonstrating compliance with the limit. The permit or requirement must also include sufficient terms and conditions such that the source cannot lawfully exceed the limit (*e.g.,* monitoring, recordkeeping, and reporting). For additional information and a summary of the EPA's position on establishing legally and practicably enforceable limits on potential emissions, including examples of ''enforceability criteria,'' see In the Matter of Yuhuang Chemical Inc. Methanol Plant St. James Parish, Louisiana, Order on Petition No. VI–2015–03 (August 31, 2016) at 13–15.

Comment: Under the 2016 NSPS subpart OOOOa, the applicability of the storage vessel standards is based on a single storage vessel's potential for VOC emissions, which is calculated using the storage vessel's ''maximum average daily throughput.'' While ''maximum average daily throughput'' is defined in 40 CFR 60.5430a of the 2016 NSPS subpart OOOOa, several stakeholders indicated that clarification of this definition was needed. As a result, the EPA proposed a revised definition. 83 FR 52106. The EPA received several comments related to the proposed definition, which requires that ''production to a single storage vessel must be averaged over the number of days production was actually sent to that storage vessel.'' Most of the commenters objected to this proposed definition, claiming that it would be more appropriate to average over the entire 30-day evaluation period rather than only those days when production was sent to the storage vessel. With regard to tank batteries, one commenter asserted that the proposed definition would not result in an accurate estimate of the potential emissions from individual storage vessels because it would overestimate the total amount of production that each tank could receive over the 30-day evaluation period. Further, the commenter stated that the proposed definition would significantly overestimate the volume of flow to the tank battery as a whole when compounded across multiple tanks and extrapolated across an entire year. Multiple commenters also generally stated that the EPA's proposed definition failed to account for the fact that maximum well production has a limit based on what the wells can produce. However, the EPA did receive one comment that agreed with the proposed definition and that owners and operators should not be able to include days where the storage vessel does not receive production when determining storage vessel applicability.

Response: The EPA disagrees with the comments suggesting that ''maximum average daily throughput'' should be determined by averaging across the full 30-day evaluation period instead of the days when production is actually sent to an individual storage vessel during that period. As stated in the proposal, the maximum average daily throughput ''was intended to represent the maximum of the average daily production rates in the first 30-day period to each individual storage vessel,'' 83 FR 52084, which is not the same as an average daily production rate based on averaging total production across a full 30-day period. As explained further in the proposal, in all possible scenarios for determining the daily production, only the number of days in which production is sent to the individual storage vessel is used for averaging, which may be less than the full 30 days in the evaluation period. Indeed, including days where no production was received would reduce the maximum average daily throughput to an individual storage vessel under any of the scenarios described in the proposal. 83 FR 52084. The commenters did not explain how averaging actual throughput to a storage vessel across the full 30 days would accurately reflect the ''maximum average daily production rates,'' therefore, we do not agree with the commenters' suggestion to use this value for the purpose of determining a storage vessel's potential for VOC emissions.

The EPA also disagrees with comments suggesting that the EPA's proposed definition would overestimate the potential for VOC emissions for individual storage vessels in a tank battery by failing to account for the overall production to the tank battery during the 30-day period. In addition to the definition of ''maximum average daily throughput'' which provided for two operational scenarios, the EPA further explained in the proposal how to determine the daily or average daily throughput, from which the maximum average daily throughput is determined, depending on how throughput is measured. 83 FR 52084. The EPA's proposed definition is based on either the daily (*i.e.,* directly measured via automated level gauging or daily manual gauging) or average daily (*i.e.,* manual gauging at the start and end of loadouts which occur over more than one day) throughput routed to a storage vessel while receiving production; the fact that the storage vessel is receiving that amount daily clearly indicates that it has the potential to do so. The total throughput to the entire tank battery during the 30-day period is not germane to this determination. Because there are likely multiple daily throughput or average daily throughput values for an individual storage vessel during the 30-day evaluation period, the maximum of those values is used to calculate the potential for VOC emissions, thus, the use of the term ''maximum average daily throughput.''

While the EPA is finalizing the definition of ''maximum average daily throughput'' as proposed, we note that the final rule provides other mechanisms for determining a storage vessel's applicability without having to calculate the maximum average daily throughput. Specifically, the final rule allows owners and operators of controlled tank batteries meeting specified criteria to average VOC emissions across the number of storage vessels in the tank battery to determine applicability for the individual storage vessels in the battery. Also, as provided in the 2016 NSPS subpart OOOOa, and unchanged by this final rule, if a facility has a legally and practicably enforceable limit that restricts production to an individual storage vessel, then it is acceptable to use this restricted production level as the maximum average daily throughput for that individual storage vessel.

Comment: Commenters stated that the methods for determining the potential for VOC emissions from storage vessels in the 2016 NSPS subpart OOOOa were not appropriate for storage vessels located at compressor stations (including gathering and boosting compressor stations) and onshore natural gas processing plants, and they indicated that the proposed revisions to 40 CFR 60.5365a(e) and the definition of maximum average daily throughput did not alleviate this problem. More specifically, commenters noted that the 2016 NSPS subpart OOOOa is clear that storage vessels at well sites must determine the potential for VOC emissions based on the maximum average daily throughput based on the first 30 days that liquids are sent to the storage vessel. The commenter noted that storage vessels at compressor stations and onshore natural gas processing plants are designed to receive liquids from multiple well sites that may start up production over a longer period of time. Because these storage vessels may not experience the same peak in throughput to the storage vessels during the first 30-days of receiving liquids as storage vessels at well sites, the commenter indicated that owners or operators may underestimate the potential emissions using the throughput for the first 30 days. Therefore, commenters requested that the EPA clarify the appropriate time period for calculating the maximum average daily throughput for storage vessels at facilities located downstream of well sites. Alternatively, commenters suggested that storage vessels at gathering and boosting compressor stations be allowed to use generally accepted engineering models that project future throughput. The commenters explained that compressor stations (including gathering and boosting compressor stations) and onshore natural gas processing plants typically utilize process simulations based on representative or actual liquid analysis to determine potential VOC emissions and volumetric condensate rates from the storage vessels based on the maximum gas throughput capacity of each facility. These generally accepted engineering models and calculation methodologies are then utilized to obtain Federal, state, local, or tribal authority issued permits to set legally and practicably enforceable limits to maintain potential VOC emissions from storage vessels at less than 6 tpy. The commenter requested that the EPA allow use of these generally accepted models and calculation methodologies to project future maximum throughput volumes.

Response: The EPA agrees with these commenters that potential VOC emissions from storage vessels at facilities downstream of well sites should not be determined based on the first 30 days that liquids are sent to those storage vessels as they are unlikely to experience the same peak in throughput during that period as storage vessels at well sites. It is the EPA's understanding, based on the information provided by the commenters and subsequent conversations,[69] that these midstream and downstream storage vessels may continue to see an increase in throughput as additional upstream well sites begin sending fluids to these compressor stations and onshore natural gas processing plants. Based on the EPA's review and understanding of the generally accepted engineering models for projecting future throughput to a storage vessel, the EPA agrees that these engineering models are appropriate for projecting the maximum throughput for purposes of calculating the potential for VOC emissions from storage vessels located downstream of well sites.

Based on the above reasons, the EPA is amending the 2016 NSPS subpart OOOOa to specifically provide the following two options for determining the potential for VOC emissions from storage vessels at facilities downstream of well sites. The first option, which is already allowed in the 2016 NSPS subpart OOOOa, allows owners or operators to take into account throughput and/or emission limits incorporated as legally and practicably enforceable limits in a permit or other requirement established under a Federal, state, local, or tribal authority. The second option allows the use of generally accepted engineering models (*e.g.,* volumetric condensate rates from the storage vessels based on the maximum gas throughput capacity of each producing facility) to project the maximum throughput used to calculate the potential for VOC emissions.

B. Major Comments Concerning Fugitive Emissions at Well Sites and Compressor Stations

In section V.B of this preamble, we discuss the significant changes from the proposal to this final rule related to the fugitive emissions requirements for well sites and compressor stations. The discussions in section V.B of this preamble include a summary of the major comments and our responses related to those changes. Specifically, section V.B of this preamble discusses the following topics: (1) The three areas of uncertainty potentially affecting the cost-effectiveness analysis that were identified in the October 15, 2018, proposal; (2) recordkeeping, reporting, and other administrative burden from the fugitive emissions requirements; (3) other updates to the model plants; and (4) cost effectiveness of fugitive emissions requirements. We also discuss our re-evaluation of BSER after consideration of all these topics.

In addition to the topics discussed in section V.B of this preamble, the EPA received comments on other aspects related to the fugitive emissions requirements. This section provides a discussion of comments and our responses regarding the following three topics: (1) The EPA's model plant analysis for low production well sites; (2) the effect of system pressure on fugitive emissions at low production well sites; and (3) monitoring of compressors at compressor stations when operating and not in standby mode. More detailed summaries and additional comments on the fugitive emissions requirements are included in Chapter 8 of the RTC document included in the rulemaking docket for this action.

Comment: The EPA created model plants representing low production well sites for purposes of analyzing the emissions and costs of a fugitive emissions monitoring and repair program at these types of well sites. In the proposal, we also acknowledged that operating pressures and production volumes are factors that can cause changes in the fugitive emissions at a well site. 83 FR 52067. However, the EPA was unable to incorporate these factors into the emission estimates in the model plants, and, therefore, developed model plants that relied on equipment and component counts to analyze fugitive emissions from low production well sites.

Some industry commenters disagreed with the use of model plants that rely on component counts alone to estimate fugitive emissions from low production wells due to differences in the type and size of equipment and operating conditions (*e.g.,* operating pressure) at low production well sites. The commenters did agree that it is reasonable to associate the number of components to the potential for leaks. However, the commenters continued to maintain that emissions from low production wells are inherently different from large production wells because of the basic physics of production and how operators change the physical equipment as production warrants. Commenters indicated that the fugitive emissions factors used by the EPA, which were developed for generally predicting emission levels, account for different types of fugitive emission components, but do not factor in the amount of production or line pressure.

Response: As stated in the proposal, the EPA continues to recognize that variations in equipment, operating conditions, and geological aspects across the country at low production well sites may affect fugitive emissions from low production well sites. As described in section V.B of this preamble, we have made updates to the low production well site model plants and re-evaluated the emissions and costs of fugitive emissions monitoring and repair requirements at low production well sites. Based on this updated analysis, the EPA concludes that fugitive emissions monitoring and repair is not cost effective at any monitoring frequency for low

[69] See memorandum for ''May 1, 2019 Meeting with GPA Midstream,'' located at Docket ID No. EPA–HQ–OAR–2017–0483.

production well sites. See section V.B of this preamble for additional discussion.

Comment: The EPA received additional comments and data related to the low production well site model plants developed and analyzed for the proposal. One commenter conducted a brief survey of its member companies' gas well site operations in 13 states and provided low production well site component counts. This commenter pointed out that the majority of emissions (around 80 percent) from the low production well site model plants are from valves and storage vessel thief hatches. Therefore, the commenter only provided counts of these components, along with the number of wellheads. This commenter explained that the data show fewer wellheads and valves than assumed in the proposal model plant for low production gas well sites. The commenter stated that it did not consider the data to be fully representative of low production well sites nationwide; nevertheless, relying on the difference in component counts, the commenter claimed that the EPA overestimated the fugitive emissions in the low production model plants used for the proposal.

Response: While the commenter specifically stated that it did not consider the data to be fully representative of low production well sites nationwide, we reviewed the information and compared it to the low production well site model plants used for the proposal analysis. Specifically, we compared the weighted-average component counts of the information provided by the commenter to the EPA's low production well site model plant. The information provided by the commenter showed that the weighted-average number of storage vessels was approximately the same as that used in the EPA model plant, the number of well heads was half (one versus two in the EPA model plant), and the number of valves was just under 25 percent (23 versus 100 in the EPA model plant). If the model plant was modified with these adjusted component counts, the overall difference in emissions would be just over 50 percent.

After consideration of this information, the EPA concluded it provides an insufficient basis to revise the low production well site model plant component counts because the information was limited to valves, connectors, and storage vessels at a sample of sites the commenter admitted were not fully representative of low production well sites. However, as discussed above in section V.B of this preamble, we did conduct further review of the data originally used to develop the model plant parameters, as well as GHGI data. That review resulted in a 35-percent decrease in the number of valves for the low production gas well site model plant, as well as decreases in the numbers of the other components. More detailed information on our analysis of the component count information submitted by commenters is contained in a technical memorandum.[70] As shown in the revised model plant analysis, a fugitive emissions monitoring program is not cost effective for low production well sites at any of the frequencies analyzed.

Comment: The EPA proposed defining low production well sites as sites where the average combined oil and natural gas production for the wells at the site is at or below 15 boe per day averaged over the first 30 days of production. 83 FR 52093. Several commenters recommended changing the definition of a low production well site to be based on the U.S. Tax Code definition of stripper wells. These commenters also recommended using 12 months of production to determine if a site is low production because most well sites newly affected by NSPS subpart OOOOa will not meet the definition based on the first 30 days of production and because production declines over time such that eventually all well sites become low production.

Response: The EPA has not adopted the stripper well definition for purposes of determining if a well site is low production in this action because the U.S. Tax Code definition applies to individual wells, not well sites. The fugitive emissions standards apply to the collection of fugitive emissions components located at a well site. Adoption of the stripper well definition could result in a scenario where one well at the site is considered low production but the other wells are not, which is inconsistent with the affected facility definition for fugitive emissions components, where the entire site is treated as one unit. Therefore, the calculation of production for purposes of determining if the well site is low production is based on the total well site production and not the individual well production averaged across the number of wells at the well site.

However, the EPA does agree with the commenters that determination of low production status based solely on the first 30 days of production does not account for decline in production over time. Therefore, the final rule specifies that a low production well site is a well site with total well site production of oil and natural gas at or below 15 boe per day. This calculation can be based on the first 30 days of production for determining initial applicability to the rule and based on a rolling 12-month average to account for production decline. See section V.B of this preamble for additional discussion.

Comment: Commenters urged the EPA to use the Department of Energy (DOE) research program[71] announced on October 23, 2018, to determine more accurate assessments of low production well emissions. The commenters asserted that the DOE study provides the EPA the opportunity to collect direct emissions data on fugitive emissions at low production well sites. The commenters concluded that these data would provide the EPA with a baseline that shows the distinctions between large wells and low production wells and the differences that may exist between types of wells and between production regions.

Response: The EPA is regularly updated on the DOE program and provides technical input on many projects. However, data from the DOE-funded study on low production wells are not currently available. The conclusions made in this final rule are based on currently available information, which includes many data sources that cover low production wells, such as DrillingInfo, Greenhouse Gas Reporting Program, and other emission measurement studies. As discussed in this section and in section V.B of this preamble, the EPA agrees that existing information shows that low production well sites may have lower emissions than well sites with higher production. As such, the final rule has separate requirements for well sites with total production at or below 15 boe per day, instead of the required fugitive emissions monitoring program (including semiannual monitoring) for well sites above this production threshold.

Comment: In addition to co-proposing annual monitoring of fugitive emissions components located at a compressor station, the EPA proposed a requirement that each compressor at the station must be monitored at least once per calendar year when it is operating. The EPA also solicited comment regarding the effect the compressor operating mode has on fugitive emissions and the proposal to require at least one monitoring a year during times that are representative of operating conditions for the compressor station.

[70] Memorandum. ''Summary of Data Received on the October 15, 2018 Proposed Amendments to 40 CFR Part 60, subpart OOOOa Related to Model Plant Fugitive Emissions.'' February 10, 2020.

[71] *https://www.netl.doe.gov/node/5775.*

Several industry commenters opposed the EPA's proposal to require that each compressor be monitored while in operation (*i.e.,* not in stand-by mode), because if the station is subject to annual monitoring (which was co-proposed), this requirement would result in a requirement for every compressor to be operating during the monitoring survey, even if all of the compressors are not needed at that time to move gas downstream. The commenters believed that the result of this requirement would be the generation of emissions from compressor blowdowns following the monitoring survey in order to return the compressors to the operating modes they were in prior to the survey. The requirement would also create unnecessary recordkeeping and scheduling complexity/burden, according to commenters. Requiring equipment to be monitored in a specific mode of operation, especially at less frequent monitoring than quarterly, would increase overall emissions if that equipment must change its operational status solely to fulfill that requirement. These commenters recommended that the EPA allow operators to conduct surveys with facility operations as they are found when the survey is conducted.

However, another commenter stated that its data suggests that it is important to conduct monitoring on fully operating compressors to maximize the number of leaks detected. The commenter stated that beyond these data, it is also simply common sense that as the ratio of pressurized to depressurized components increases, so will the number of leaks detected (depressurized components do not leak). One of the problems is that operation modes vary seasonally at each compressor station, and within each compressor station, the operating modes of each unit can vary daily based on demand. The commenter asserted that the current quarterly compressor monitoring frequency creates a higher probability of conducting a survey where each compressor is monitored in a pressurized mode at least once per year. If the EPA moved to less frequent monitoring, the commenter recommended that there should be some condition to ensure that a reasonable effort is made to schedule the surveys during a time of peak operation.

Response: The EPA reviewed the input provided by the commenters. While we agree with the one commenter that the opportunity for fugitive emissions is greater when a compressor is pressurized and operating, the EPA is not finalizing the proposed requirement that each compressor must be monitored while in operation (*i.e.,* not in stand-by mode) at least annually. The EPA has specified in the final rule that the monitoring survey of fugitive emissions components at a gathering and boosting compressor station is semiannual after the initial survey and subsequent semiannual monitoring surveys must be conducted at least every 4 to 7 months. Therefore, as pointed out by the commenter, the likelihood that all monitoring events in a year will be when a specific individual compressor is not operating is relatively low. For the reason stated above, this final rule does not require monitoring of each individual compressor at the station while it is in operation (*i.e.,* not in stand-by mode) at least once per calendar year.

However, the EPA does conclude that it is important that the operating mode during the monitoring survey be recorded. While we would not expect that owners or operators would modify their operating schedules to avoid monitoring when the compressor is operating, or that they would purposely schedule every monitoring event during shutdown periods, we believe that this record would inform the Agency if this were occurring and, if so, how often. This information will provide valuable points for future analyses on leak rates and operating modes. Therefore, the final rule requires that owners and operators keep a record of the operating mode of each compressor at the time of the monitoring survey.

C. Major Comments Concerning AMELs

1. Emerging Technologies

The EPA received comments related to AMELs for emerging technologies on several topics. The comments received by the EPA that resulted in significant rule changes are discussed in section V.C.1 of this preamble, along with our response and rationale for the changes. The specific topics were (1) who can submit an AMEL application, (2) what data can or must be included in an AMEL application, and (3) what broader applications of alternatives are permitted. Further details on comments related to the broader applications of AMEL technology, specifically on the issues of applying AMEL to multiple similar sites or to categories of sources, are provided below along with the EPA's responses. Other comments, and more detailed comments covering the topics discussed in this preamble related to emerging technologies can be found in the RTC document available in the docket, along with EPA's responses.

Comment: In the proposal, the EPA reiterated its position that AMEL approvals would be made on a site-specific basis but noted that applicants could include multiple sites within one application as necessary. Many commenters disagreed with that proposal, stating that the EPA should allow approved AMELs to apply more broadly to multiple sites, basin-wide, industry-wide, or even based on nation-wide efficacy. Commenters asserted that restricting AMEL approval to a specific site is inconsistent with the EPA's past practice for OGI, in which the EPA determined that OGI achieves emission reductions equivalent to Method 21 for several industries and source categories in a single rulemaking.[72] Some commenters feared that the site-specific approval process that includes **Federal Register** notice and comment requirements is so onerous that it will stifle innovation in new technology, and another noted that its customers have indicated that they would not apply for an AMEL if approval is site-specific. Commenters pointed out that the site-specific approval process could create a crush of AMEL applications for hundreds or thousands of sites, but the applications would be limited to only the technologies previously approved or most likely to be approved as AMEL.

In response to the EPA's concern that alternative technologies may need to be adjusted for site-specific conditions, such as gas compositions, allowable emissions, or the landscape, several commenters suggested that the EPA could account for factors affecting variability, such as the weather or landscaping, by imposing conditions for the use of the technology and/or require periodic instrument checks, calibration records, or other actions to ensure equivalent emission reductions are achieved within the approved AMEL. The commenters also noted that if there is concern about allowable emissions impacting the usability of a particular technology, that technology may only be approvable for use as an approach to direct inspection efforts, but this factor would not affect the ability for it to be approved for that use at multiple sites.

Response: The EPA does not seek to stifle innovation of emerging technologies. In fact, the Agency is actively involved in many multi-stakeholder groups aimed at developing frameworks and criteria that will promote the development of possible alternatives. As such, the EPA strongly encourages interested parties to discuss possible alternatives with the Agency.

[72] See the Alternative Work Practice located at 40 CFR 60.18(g), (h), and (i).

However, the EPA disagrees that this final rule should be the vehicle used to make determinations about any particular technology because the proposed rulemaking did not evaluate any specific technology. The EPA also disagrees that this rule is inconsistent with the EPA's past practice for OGI, in which the EPA allowed the use of OGI as an alternative to Method 21 for several industries and source categories in a single rulemaking.[73] The EPA notes that while the AMEL process provided for in CAA section 111(h)(3) contains elements similar to a rulemaking (such as notice and opportunity for public hearing), approval of an alternative does not always require rulemaking. If a technology is developed that could be broadly applied to oil and gas sites as an alternative to what is required in NSPS subpart OOOOa, it may be more appropriate to incorporate such a technology into the rule through a formal rulemaking process so that every affected facility can make use of that alternative.

As discussed in section V.C.1 of this preamble, the EPA agrees that in some circumstances, it may be appropriate to apply an approved AMEL to multiple sites, including future sites. If the applicant of an AMEL believes that it is appropriate to apply the alternative to more sites than those listed in the application, the applicant should specify this within the application and provide any characteristics or variables that are applicable to the type of sites where the equivalency demonstration is being made. Specifically, the applicant should provide relevant information, including any specific conditions (*e.g.,* technology-specific variables that affect performance), procedures (*e.g.,* specific work practice that will be followed to identify emissions and make repairs), or site characteristics under which the alternative must be applied (*e.g.,* formation variables, site operating conditions, equipment at the site, etc.), to demonstrate equivalence with the emissions reductions that would be achieved under the requirements of the NSPS. The EPA will evaluate these defined conditions and additional conditions, if any, under which it might be appropriate to allow future use of the alternative once approved via the AMEL process. For example, the EPA might approve the use of a specific fugitive emissions detection technology that operates with the same performance under specific work practice requirements, environmental conditions, and site configurations and operations. In that example, the EPA might determine it is appropriate to approve the AMEL and define the specific parameters (*e.g.,* environmental conditions, site configurations, and operations) within the approval to allow the use of that alternative at sites meeting those same conditions without the need for additional future application to the EPA. However, each of these determinations would necessarily be made on a case-by-case basis provided the application contains all necessary information to make such a broad determination for applicability of the AMEL. Given that these determinations are made on facts and showings that are specific to each proposed alternative, the EPA has determined that the best course forward is for an applicant to submit an application seeking a broadly applicable AMEL and for the Agency to then use its evaluation of that application as a template for future applications, thereby streamlining the process.

Comment: Several commenters stated that the EPA should approve the use of alternative technologies under the Agencies' AMEL authority for broad categories of sources subject to NSPS subpart OOOOa, such as fugitive emissions components across multiple sites. They remarked that there is nothing in the statute that requires the EPA to set source-specific AMELs, and the EPA's position regarding the necessity of source-by-source applications and approvals for AMEL is incorrectly taken from a narrow reading of the language of CAA section 111(h)(3). The commenters stated that, while the language of CAA section 111(h)(3) provides that an AMEL is permitted to be used ''by the source'' for purposes of compliance, the EPA's reading of this provision to disallow the granting of AMEL for use by multiple sources is inconsistent with the NSPS approach of developing standards for whole categories of sources.

Some commenters said that because an AMEL will serve as a replacement for a category-wide CAA section 111(h)(1) standard, a demonstration that an AMEL will achieve an emission reduction at least equivalent to a CAA section 111(h)(1) standard could be made on a category-wide basis and be applied to an entire source category. These commenters suggested that allowing for source category-wide AMEL determinations would be consistent with the overall structure of CAA section 111 and its focus on category-wide standards under CAA sections 111(b) and (h)(1) and with the limitation prohibiting the EPA from imposing specific technological emission reduction requirements pursuant to CAA section 111(b)(5).

These commenters further stated that the EPA's regulation implementing CAA section 112(h)(3) recognizes that the EPA is authorized to approve an AMEL for ''source(s) or category(ies) of sources on which the alternative means will achieve equivalent emission reductions.''[74] They contended that, given the similarities between the programs authorized under CAA section 111 and CAA section 112, and particularly the similarity of CAA sections 111(h)(3) and 112(h)(3), the EPA should adopt a policy of applying an AMEL to source categories for CAA section 111(h)(3) in the same manner as it has done with respect to CAA section 112(h)(3). They noted that in other rules, such as the visibility provisions that require the best available retrofit technology (BART), the EPA's rules allow the EPA and the states to authorize BART alternatives that can apply to groups of sources and that allow emission averaging across sources, even over wide regions, rather than imposing source-specific emission limits or source-specific alternatives to such limits. The commenters stated that if alternatives to emission limits (or work practice standards) for groups of sources under these provisions are permissible despite the continued references to the term ''source'' in the statutory language, then a source category-wide AMEL is surely permissible under CAA section 111(h)(3).

Response: On the first point raised by commenters, and as explained in the EPA's response above, the EPA agrees that in some instances broad use of an approved alternative may be appropriate. The current construct of the AMEL application process in NSPS subpart OOOOa does not prevent the EPA from taking this path as suggested by the commenters.

The commenters also suggest that the EPA should apply AMEL to a source category in the same manner in which the EPA has done for applications submitted through section 112(h)(3) of the CAA. While the EPA has approved AMEL for sources subject to standards under section 112 of the CAA, these approvals have been made on a site-specific basis, in which each application specifically lists the facilities that are applying for approval. Further, while similar, CAA section 112(h)(3) does not apply for purposes of demonstrating equivalence with work practice standards in the NSPS.

[73] See 40 CFR 60.18(g), (h), and (i).

[74] See 40 CFR 63.6(g)(1).

For purposes of evaluating whether an alternative to fugitives monitoring provides at least equivalent emission reductions as the applicable standards in the context of NSPS subpart OOOOa, the EPA asserts that the emissions from an individual site are the only appropriate measure for comparison. First, the BSER determination for the collection of fugitive emissions components is based on a single well site, or a single compressor station, not a collection of well sites and/or compressor stations, and not the emissions of the entire source category. The source category for which NSPS subpart OOOOa sets standards of performance under CAA section 111 is the Crude Oil and Natural Gas Production source category. This category is defined in 40 CFR 60.5430a as crude oil production, which includes the well and extends to the point of custody transfer to the crude oil transmission pipeline or any other forms of transportation; and natural gas production and processing, which includes the well and extend to, but does not include, the point of custody transfer to the natural gas transmission and storage segment.[75] Within this source category, the EPA has set standards of performance (BSER) for individual affected facilities. These affected facilities are the only emission sources within the Crude Oil and Natural Gas Production source category for which these NSPS apply and are defined in 40 CFR 60.5365a.

Specifically, the EPA has defined the collection of fugitive emissions components at a well site and the collection of fugitive emissions components at a compressor station as individual affected facilities in the rule. Affected facilities are defined at the individual site level, and not as the collection of fugitive emissions components across multiple sites, or a collection of sources within a basin. Further, the standards that apply to these affected facilities are specific to the individual well site or compressor station, as defined in 40 CFR 60.5365a(i) and (j) and 40 CFR 60.5397a. For example, the collection of fugitive emissions components at an existing well site become subject to the fugitive emissions requirements when (1) a new well is drilled at that well site, (2) an existing well at that well site is hydraulically fractured, or (3) an existing well at that well site is hydraulically refractured. In all three cases, the event that triggers the requirements for an existing well site are based on site-specific changes, and not changes at other nearby sites. Drilling a new well at a well site within the same basin, for instance, does not trigger the fugitive emissions requirements for all well sites located in that basin.

When establishing the requirements for the collection of fugitive emissions components, the EPA limited the applicability to individual well sites or compressor stations. The work practice standards set in accordance with section 111(h)(1) of the CAA were established for the collection of fugitive emissions components at an individual well site or compressor station. Since the NSPS does not define the emission source subject to BSER as a basin, or other aggregation of emission points, the EPA finds it inappropriate to evaluate alternatives that seek to implement such a definition. As a practical matter, the EPA concludes that any determination of equivalent emission reductions through an AMEL under section 111(h)(3), or for an alternative work practice under section 111(h)(1), of the CAA for these NSPS should be determined at the same affected facility level (*i.e.,* collection of fugitive emissions components at a well site or at a compressor station) as the original work practice standards.

Similar to the EPA's explanation in the Affordable Clean Energy rule (''ACE''), here the EPA does not need to determine whether it would have reasonable grounds to define ''source'' for purposes of the fugitive emissions monitoring work practice standard as a geographic area, such as a basin. Because these NSPS define an affected facility for this purpose as the collection of fugitive emissions components at a well site, and the collection of fugitive emissions components at a compressor station, the EPA does not think it is appropriate for AMEL applications to accommodate the averaging of emissions.[76]

Second, it is unclear whether the commenters are suggesting that such aggregation would take into account emissions from sources within a basin not subject to these NSPS, such as existing oil and gas well sites or compressor stations, or sources that emit VOC that are included in a different source category. In response to this point, the EPA directs commenters to the discussion of CAA section 111, generation shifting, and emission offsets included in ACE.[77] ''[T]he plain language of CAA section 111 does not authorize the EPA to select as the BSER a system that is premised on application to the source category as a whole or to entities entirely outside the regulated source category.'' [78] This principle also applies in the context of evaluating alternatives to the established BSER.

Lastly, commenters suggest that averaging should be appropriate here because the EPA allows averaging in its BART program. However, that comparison is not appropriate because it fails to consider differences between BART and the BSER for this NSPS. The BART requirement is just one component of a larger strategy to make reasonable progress towards the national goal of remedying visibility impairment in certain areas. The EPA determined in the BART context that if a state can demonstrate that an alternative strategy, such as an emissions trading scheme, will be even more effective at improving visibility, such a ''better-than-BART'' strategy may be adopted to fulfill the role that would otherwise by filled by BART. However, in the context of this NSPS there is less flexibility on this point than in the BART program because, as explained above, there are no other components to reducing emissions aside from the BSER, the BSER is not based on reasonable progress, and this NSPS does not define the emission source subject to BSER as a basin or other aggregation of emission points.

2. State Fugitive Emissions Programs

The EPA received comments related to the alternative fugitive emissions standards on several topics. The comments received by the EPA that resulted in significant rule changes are discussed in section V.C.2 of this preamble, along with our response and rationale for the changes. Specifically, these topics were related to whether the state regulations/requirements determined to be alternative fugitive standards to NSPS subpart OOOOa fugitive requirements will provide adequate coverage of the emission sources in the state and the potential for duplicative reporting and recordkeeping requirements. Further details on comments related to these topics are provided below, along with other significant comments and the EPA's responses. Other comments, and more detailed comments covering the topics discussed in this preamble, related to the state fugitive monitoring programs can be found in the RTC document

[75] See the Review Rule published in the **Federal Register** of Monday, September 14, 2020 and supporting information located at Docket ID No. EPA–HQ–OAR–2017–0757.

[76] See 81 FR 32520, 32556 and 57 (July 8, 2019) (section titled ''Averaging and Trading'').

[77] *Id.* at 32523–26.

[78] *Id.* at 32524.

available in the docket, along with the EPA's responses.

Comment: The EPA proposed alternative fugitive emissions standards based on our determination that certain states had existing requirements equivalent to the proposed fugitive emissions requirements. These determinations were based on qualitative assessments comparing various aspects of the requirements, such as monitoring frequencies and repair deadlines. Two commenters stated that the equivalency determinations must be quantitative if the EPA wants to set alternative standards because they are similar to AMELs. The commenters indicated that the Agency's analysis evaluated whether a state has regulations that are similar to the EPA's regulations, rather than whether the emissions reductions achieved by those regulations are quantitatively equivalent. One of the commenters stated that the EPA's qualitative comparison is legally insufficient because it does not meet the statutory requirement that an applicant ''establish'' that an AMEL ''will achieve'' reductions in emissions ''at least equivalent to'' the reduction achieved under the Federal standards.[79] This commenter stated that, without a quantitative comparison, it is impossible to determine whether an AMEL will achieve at least an equivalent reduction in pollutant emissions. The commenter further notes that past AMEL approvals under this provision were based on detailed quantitative determinations for each facility to determine the exact emissions levels that would be achievable at that facility, and then those levels were compared to the emissions levels achievable under the present NSPS. The commenter stated that the EPA's policy changes in how equivalency is determined are inconsistent with the requirements of section 111(h) of the CAA and also stated that the EPA's approach of ''combining . . . aspects of the state requirements to formulate alternatives,'' [80] to determine equivalency is not a permissible or reasonable approach. The commenter noted that while some aspects of a state-level program may be more protective than the corresponding Federal requirements, others may not be, and the commenter stated that qualitative comparisons cannot determine the net effects of program elements that point in opposite directions.

Response: The EPA agrees that in some instances when the EPA is evaluating an alternative, it would be preferable to use a quantitative analysis, but we do not agree that such analysis is necessary or prudent in this instance for determining the equivalency of fugitive emissions requirements in state regulations. The CAA does not require the EPA to conduct a quantitative analysis to evaluate an alternative standard or to determine whether that alternative is equivalent to the underlying standard. Work practice standards under section 111(h)(1) of the CAA are set when ''it is not feasible to prescribe or enforce a standard of performance.'' Section 111(h)(2) of the CAA further defines that the phrase not feasible to prescribe or enforce a standard of performance means any situation in which the Administrator determines that: (A) A pollutant or pollutants cannot be emitted through a conveyance designed and constructed to emit or capture such pollutant; or (B) the application of measurement methodology to a particular class of sources is not practicable due to technological or economic limitations. Fugitive emissions are not quantified within the rule, and the technologies used in this rule to detect fugitive emissions do not quantify the actual emissions that are detected and then remediated through repair. Further, even if direct quantification were possible through the currently approved technologies, those quantified emissions would only represent the fugitive emissions detected on that specific day and would not offer information related to how long those emissions were present prior to detection, or account for any emissions that occur between monitoring surveys. Due to the fact-specific circumstances of the work practice standard in the existing rule, it is not practical for the EPA to conduct an accurate and meaningful quantitative analysis of the alternatives. It is also not necessary for the EPA to conduct a quantitative analysis. The statute does not require a quantitative analysis. Therefore, the most practical way to evaluate the equivalence of a fugitive emissions monitoring and repair program is through the site-specific qualitative comparison that we used. It is the EPA's determination that the analysis, which evaluates the types of components monitored, the frequency of monitoring, the detection instrument, the threshold that triggers repairs, and the repair deadline, is sufficient and appropriate for demonstrating that the six programs identified as alternative fugitive standards are equivalent to the fugitive emissions requirements of NSPS subpart OOOOa.[81] Therefore, we have not conducted a quantitative analysis of the individual state programs that are finalized in this action as alternative standards.

Comment: One commenter performed its own quantitative assessment of the state programs that the EPA proposed as equivalent to NSPS subpart OOOOa with the October 15, 2018, proposal. From this analysis, the commenter stated that it found differences in the applicability thresholds for several of the state programs, which results in the state programs (combined) covering only 34 percent of the total wells that would be covered by the proposal or the 2016 NSPS subpart OOOOa in these states. The commenter also stated that state programs vary in stringency and may not reduce emissions to the same level as the EPA standards, such as the Ohio and Texas provisions that allow for inspection frequency to decrease based on the percentage of components leaking. The commenter asserted that its assessment demonstrates that both the Ohio and Texas programs reduce emissions to a lesser extent than the proposed requirements, while California and Colorado meet the emission reduction levels accomplished by the proposal. Overall, the commenter said that the state programs will achieve a reduction of methane emissions that is 36 percent less than the reduction that would be achieved by the amendments proposed on October 15, 2018. When compared to the 2016 NSPS subpart OOOOa requirements, the commenter said that the state programs would result in 58 percent less emissions reductions. The commenter remarked that these findings demonstrate that these state programs are not equivalent to either the proposal or the 2016 NSPS subpart OOOOa. Another commenter also remarked that the California Air Resources Board has performed a preliminary assessment of state programs against the 2016 NSPS subpart OOOOa and found that only the California, Colorado, Pennsylvania, Utah, and Texas programs (within narrow parameters) are likely to be equivalent.

Response: The EPA reviewed the analysis provided by the commenter but notes that the analysis appears to include an incorrect assumption. Specifically, the commenter stated that only 34 percent of the wells covered by the fugitive emissions requirements in NSPS subpart OOOOa and that are also

[79] See CAA section 111(h)(3).

[80] See 83 FR 52081.

[81] See memorandum, ''Equivalency of State Fugitive Emissions Programs for Well Sites and Compressor Stations to Final Standards at 40 CFR part 60, subpart OOOOa,'' located at Docket ID No. EPA–HQ–OAR–2017–0483. January 17, 2020.

located in one of the six states with proposed alternative fugitive standards would actually be subject to those alternative fugitive standards. This is not correct. The assumption by the commenter is that the alternative standards are deficient because not all of the sites that are currently subject to NSPS subpart OOOOa would be required to monitor and, thus, reduce fugitive emissions. This assumption is incorrect. The applicability criteria found in NSPS subpart OOOOa will continue to apply regardless of the state's applicability criteria.

Using Texas as an example, the commenters stated that only 5 percent of the sites that are subject to NSPS subpart OOOOa would have monitoring requirements under the alternative fugitive standards for well sites located in Texas. While this percentage may represent those sites in Texas that can utilize the alternative, this does not mean that the other 95 percent of sites escape regulation under the NSPS. If a well site is subject to the Texas standards, then that well site may opt to comply with those State-level standards as an alternative to certain Federal fugitive emissions requirements in NSPS subpart OOOOa. However, if a well site located in Texas is not subject to the State-level requirements and is subject to the NSPS (95 percent of the sites according to the commenter), then the alternative standard would not be available to that site, and monitoring would be required through the requirements in NSPS subpart OOOOa. Put another way, the alternatives included in this final rule do not alter the applicability criteria of the NSPS for any sites. If a well site in Texas was required to comply with the NSPS before the alternative was approved, then that site is still required to comply with the NSPS, but the final rule affords certain sites an alternative way to demonstrate that compliance with the NSPS, if they so choose. Moreover, regardless of whether the site complies with the fugitive emissions requirements in NSPS subpart OOOOa, or the alternative fugitive standards for their state, they must conduct the specific monitoring and repair for the NSPS subpart OOOOa defined fugitive emissions components at a well site or compressor station, as applicable.

Comment: Several commenters asserted that the EPA should recognize the approved state programs as wholly equivalent to the fugitive emissions requirements in the NSPS and fully delegate the implementation of those fugitive emissions requirements to those states, including the states' recordkeeping and reporting requirements. The commenters noted that the EPA is requiring operators to use the fugitive emission component definition from the 2016 NSPS subpart OOOOa and the 2016 NSPS subpart OOOOa reporting and monitoring plan.

Two of the commenters observed that they are required to comply with both the state requirements and Federal fugitive emissions programs concurrently. The commenters stated that complying with two different recordkeeping and reporting schemes for the same site is very burdensome with no added benefit for the environment. Sites that operate where they are subject to both the NSPS and a state program will sometimes be required to keep two very similar sets of records to comply with both standards. Likewise, sites in this situation may be required to report similar overlapping information to both the Federal system and a state system. According to commenters, this overlap in recordkeeping and reporting (and sometimes in monitoring plans) creates redundant work that unnecessarily consumes resources. The commenters go on to assert that requiring the Federal reporting and monitoring plan defeats the purpose and any benefit from the EPA approving state programs and suggest that if a state program is not adequate in the EPA's opinion, then the EPA should address the issue with the individual state, so it can be approved in whole. Commenters added that as an alternative, the EPA could require that the fugitive emissions component definition from NSPS subpart OOOOa be used when following an alternative standard, even if the state program definitions differ, but the EPA should not require any duplicative administrative burden.

Further, the commenters stated that CAA Section 111 fits squarely within the cooperative federalism tradition, with CAA section 111(c) expressly calling on states to develop ''a procedure for implementing and enforcing standards of performance for new sources'' and calling on the Administrator to delegate ''any authority he has . . . to implement and enforce such standards.'' [82] Two commenters noted that the EPA did not evaluate the equivalency of state reporting requirements or monitoring plans and, thus, did not propose any alternative standards for these aspects of the NSPS subpart OOOOa fugitive emissions requirements. These commenters stated that the exclusion of state reporting and monitoring plan requirements from the EPA's equivalency evaluation leaves the regulated community in certain states subject to potentially duplicative regulation.

Response: It is unclear to the EPA what commenters mean by ''wholly equivalent'' and ''fully delegate,'' but we are providing a response based on our interpretation that commenters are requesting approved alternative standards only require recordkeeping and reporting to the individual states and not to the EPA. After considering the comments provided, the EPA reviewed the recordkeeping and reporting requirements for each of the six states that were proposed for alternative fugitive standards in the October 15, 2018, proposal (California, Colorado, Ohio, Pennsylvania, Texas, and Utah). For California, Ohio, and Pennsylvania, the EPA was able to identify site-specific reporting requirements in the state reports which, while not identical to the reporting for NSPS subpart OOOOa, were determined to be appropriate to demonstrate compliance with the alternative fugitive standards for those states. Therefore, in this final rule, we are allowing well sites and compressor stations located in California, Ohio, and Pennsylvania that adopt the alternative fugitive standards to electronically submit a copy of the report that is submitted to their state as specified in 40 CFR 60.5420a(b)(7)(iii). As discussed in section V.C of this preamble, this report must be submitted in the format in which it was submitted to the state, noting the following order of preference: (1) As a binary file, (2) as a XML schema, (3) as a searchable PDF, or (4) as a scanned PDF of a hard copy.

In reviewing the reporting requirements for Colorado, we noted that the report is a fillable form to the state that summarizes all monitoring events for that year at the company-level. Therefore, no site-specific information is available. We then reviewed the recordkeeping forms for Colorado to identify what information is required for the individual sites and compared that information to the required annual report for NSPS subpart OOOOa. We identified one recordkeeping element required by NSPS subpart OOOOa that was not already included in the recordkeeping requirements for Colorado: Deviations from certain requirements in the monitoring plan. Given that the Federal monitoring plan, and deviations from that plan, are still required for all sites that adopt the alternative fugitive standards, there are no additional recordkeeping elements that would be needed beyond what the State already requires. While the EPA has determined

[82] See CAA section 111(c)(1).

that the Colorado program for fugitive emissions requirements is an acceptable alternative to NSPS subpart OOOOa, the company-level reports in Colorado are insufficient to demonstrate compliance for individual sites. Therefore, we are still requiring that well sites and compressor stations located in Colorado that adopt the alternative fugitive standard must report the information required by NSPS subpart OOOOa for fugitive emissions components at well sites and compressor stations.

Our review of the Texas reporting requirements found that sites only report information when fugitive emissions are found. While this may be appropriate for demonstrating compliance to the State, it is not adequate information for the EPA to ensure compliance with the alternative fugitive standards for well sites and compressor stations located in Texas. Similar to Colorado, we examined the recordkeeping requirements and found that sites located in the State are already required by the State to keep records that facilitate the reporting required by NSPS subpart OOOOa for fugitive emissions components at well sites and compressor stations. Therefore, we are requiring that well sites and compressor stations located in Texas that adopt the alternative fugitive standards must report the information required in NSPS subpart OOOOa.

Finally, the requirements in Utah do not include reporting. Similar to Colorado and Texas, we reviewed the recordkeeping requirements. For Utah, sites must keep records of the monitoring plan and the monitoring surveys. We found these records are similar to the information that is required in the NSPS subpart OOOOa report for fugitive emissions components and would not require additional recordkeeping. Therefore, we are requiring that well sites located in Utah that adopt the alternative fugitive standards must report the information required in NSPS subpart OOOOa.

VII. Impacts of These Final Amendments

A. What are the air impacts?

The EPA projected that, from 2021 to 2030, relative to the baseline, the final rule will forgo about 450,000 short tons of methane emissions reductions (10 million tons CO_2 Eq.), 120,000 short tons of VOC emissions reductions, and 4,700 short tons of HAP emission reductions from facilities affected by this reconsideration. The EPA estimated regulatory impacts beginning in 2021 as it is the first full year of implementation of this rule. The EPA estimated impacts through 2030 to illustrate the accumulating effects of this rule over a longer period. The EPA did not estimate impacts after 2030 for reasons including limited information, as explained in the RIA.

B. What are the energy impacts?

There will likely be minimal change in emissions control energy requirements resulting from this rule. Additionally, this final action continues to encourage the use of emission controls that recover hydrocarbon products that can be used on-site as fuel or reprocessed within the production process for sale. The energy impacts described in this section are those energy requirements associated with the operation of emission control devices. Potential impacts on the national energy economy from the rule are discussed in the economic impacts section.

C. What are the compliance cost reductions?

The PV of the regulatory compliance cost reduction associated with this final rule over the 2021 to 2030 period was estimated to be $800 million (in 2016 dollars) using a 7-percent discount rate and $1.0 billion using a 3-percent discount rate. The EAV (rounded to two significant figures) of these cost reductions is estimated to be $110 million per year using either a 7-percent or 3-percent discount rate.

These estimates do not, however, include the forgone producer revenues associated with the decrease in the recovery of saleable natural gas, though some of the compliance actions required in the baseline would likely have captured saleable product that would have otherwise been emitted to the atmosphere. Estimates of the value of the recovered product were included in previous regulatory analyses as offsetting compliance costs. Because of the deregulatory nature of this final action, the EPA projected a reduction in the recovery of saleable product. Using the 2020 Annual Energy Outlook (AEO) projection of natural gas prices to estimate the value of the change in the recovered gas at the wellhead projected to result from the final action, the EPA estimated a PV of regulatory compliance cost reductions of the final rule over the 2021 to 2030 period of $750 million using a 7-percent discount rate and $950 million using a 3-percent discount rate. The corresponding estimates of the EAV of cost reductions after accounting for the forgone revenues were $100 million per year using a 7-percent discount rate and $110 million per year using a 3-percent discount rate.

D. What are the economic and employment impacts?

The EPA used the National Energy Modeling System (NEMS) to estimate the impacts of the 2016 NSPS subpart OOOOa on the U.S. energy system. The NEMS is a publicly available model of the U.S. energy economy developed and maintained by the U.S. Energy Information Administration and is used to produce the AEO, a reference publication that provides detailed projections of the U.S. energy economy. The EPA estimated small impacts on crude oil and natural gas markets of the 2016 NSPS subpart OOOOa rule over the 2020 to 2025 period. This final rule will result in a decrease in total compliance costs relative to the baseline. Therefore, the EPA expects that this rule will partially reduce the impacts estimated for the 2016 NSPS subpart OOOOa in the 2016 NSPS subpart OOOOa RIA.

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). While a standalone analysis of employment impacts is not included in a standard benefit-cost analysis, such an analysis is of concern in the current economic climate given continued interest in the employment impact of regulations such as this final rule. The EPA estimated the changes in compliance-related labor impacts due to the changes finalized in this rule. As presented in the RIA for this action, the EPA projected there will be reductions in the labor required for compliance-related activities associated with the 2016 NSPS subpart OOOOa requirements relating to fugitive emissions monitoring and certifications of CVS.

E. What are the forgone benefits?

The EPA expects forgone climate and health benefits due to the forgone emissions reductions projected under this final rule. The EPA estimated the forgone domestic climate benefits from the forgone methane emissions reductions using an interim measure of the domestic social cost of methane (SC-CH_4). The SC-CH_4 estimates used here were developed under Executive Order 13783 for use in regulatory analyses until an improved estimate of the impacts of climate change to the U.S.

can be developed based on the best available science and economics. Executive Order 13783 directed agencies to ensure that estimates of the social cost of GHG used in regulatory analyses ''are based on the best available science and economics'' and are consistent with the guidance contained in Office of Management and Budget (OMB) Circular A–4, ''including with respect to the consideration of domestic versus international impacts and the consideration of appropriate discount rates'' (Executive Order 13783, Section 5(c)). In addition, Executive Order 13783 withdrew the TSDs and the August 2016 Addendum to these TSDs describing the global social cost of GHG estimates developed under the prior Administration as no longer representative of government policy. The withdrawn TSDs and Addendum were developed by an interagency working group that included the EPA and other executive branch entities and were used in the 2016 NSPS subpart OOOOa RIA.

The EPA estimated the PV of the forgone domestic climate benefits over the 2021 to 2030 period to be $19 million under a 7-percent discount rate and $71 million under a 3-percent discount rate. The EAV of these forgone benefits is estimated $2.5 million per year under a 7-percent discount rate and $8.1 million per year under a 3-percent discount rate. These values represent only a partial accounting of domestic climate impacts from methane emissions and do not account for health effects of ozone exposure from the increase in methane emissions.

Under the final rule, the EPA expects that forgone VOC emission reductions will degrade air quality and are likely to adversely affect health and welfare associated with exposure to ozone, $PM_{2.5}$, and HAP, but we did not quantify these effects at this time due to the data limitations described below. This omission should not imply that these forgone benefits may not exist; rather, it reflects the inherent difficulties in accurately modeling the direct and indirect impacts of the projected reductions in emissions for this industrial sector. To the extent that the EPA were to quantify these ozone and PM impacts, it would estimate the number and value of avoided premature deaths and illnesses using an approach detailed in the Particulate Matter NAAQS and Ozone NAAQS RIAs.[83] [84] This approach relies on full-form air quality modeling. The Agency is committed to assessing ways of conducting full-form air quality modeling for the oil and natural gas sector that would be suitable for use in regulatory analysis in the context of NSPS, including ways to address the uncertainties regarding the scope and magnitude of VOC emissions.

When quantifying the incidence and economic value of the human health impacts of air quality changes, the Agency sometimes relies upon alternative approaches to using full-form air quality modeling, called reduced-form techniques, often reported as ''benefit-per-ton'' values that relate air pollution impacts to changes in air pollutant precursor emissions.[85] A small, but growing, literature characterizes the air quality and health impacts from the oil and natural gas sector.[86] [87] [88] The Agency feels more work needs to be done to vet the analysis and methodologies for all potential approaches for valuing the health effects of VOC emissions before they are used in regulatory analysis, but is committed to continuing this work. Recently, the EPA systematically compared the changes in benefits, and concentrations where available, from its benefit-per-ton technique and other reduced-form techniques to the changes in benefits and concentrations derived from full-form photochemical model representation of a few different specific emissions scenarios.[89] The Agency's goal was to create a methodology by which investigators could better understand the suitability of alternative reduced-form air quality modeling techniques for estimating the health impacts of criteria pollutant emissions changes in the EPA's benefit-cost analysis, including the extent to which reduced form models may over- or under-estimate benefits (compared to full-scale modeling) under different scenarios and air quality concentrations. The EPA Science Advisory Board (SAB) recently convened a panel to review this report.[90] In particular, the SAB will assess the techniques the Agency used to appraise these tools; the Agency's approach for depicting the results of reduced-form tools; and, steps the Agency might take for improving the reliability of reduced-form techniques for use in future RIAs.

VIII. Statutory and Executive Order Reviews

Additional information about these statutes and Executive orders can be found at *https://www.epa.gov/laws-regulations/laws-and-executive-orders.*

A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review

This action is an economically significant regulatory action that was submitted to 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 RIA is available in the docket. The RIA describes in detail the basis for the EPA's assumptions and characterizes the various sources of uncertainties affecting the estimates below.

Table 6 shows the present value and equivalent annualized value of the costs, benefits, and net benefits of the final rule for the 2021 to 2030 period relative to the baseline using discount rates of 7 and 3 percent, respectively. The table also shows the total forgone emission reductions projected from 2021 to 2030 relative to the baseline. In the following table, we refer to the compliance cost reductions as the ''benefits'' and the forgone benefits as the ''costs'' of this final action. The net benefits are the benefits (total cost

[83] U.S. EPA. December 2012. ''Regulatory Impact Analysis for the Final Revisions to the National Ambient Air Quality Standards for Particulate Matter.'' EPA–452/R–12–005. Office of Air Quality Planning and Standards, Health and Environmental Impacts Division. *https://www3.epa.gov/ttnecas1/regdata/RIAs/finalria.pdf.* Accessed January 9, 2020.

[84] U.S. U.S. EPA. September 2015. ''Regulatory Impact Analysis of the Final Revisions to the National Ambient Air Quality Standards for Ground-Level Ozone.'' EPA–452/R–15–007. Office of Air Quality Planning and Standards, Health and Environmental Impacts Division. *https://www3.epa.gov/ttnecas1/docs/20151001ria.pdf.* Accessed January 9, 2020.

[85] U.S. EPA. 2018. ''Technical Support Document: Estimating the Benefit per Ton of Reducing $PM_{2.5}$ Precursors from 17 Sectors.'' February. *https://www.epa.gov/sites/production/files/2018-02/documents/sourceapportionmentbpttsd_2018.pdf.* Accessed January 9, 2020.

[86] Fann, N., K.R. Baker, E.A.W. Chan, A. Eyth, A. Macpherson, E. Miller, and J. Snyder. 2018. ''Assessing Human Health $PM_{2.5}$ and Ozone Impacts from U.S. Oil and Natural Gas Sector Emissions in 2025.'' Environmental Science and Technology 52(15):8095–8103.

[87] Litovitz, A., A. Curtright, S. Abramzon, N. Burger, and C. Samaras. 2013. ''Estimation of Regional Air-Quality Damages from Marcellus Shale Natural Gas Extraction in Pennsylvania.'' Environmental Research Letters 8(1), 014017.

[88] Loomis, J. and M. Haefele. 2017. ''Quantifying Market and Non-market Benefits and Costs of Hydraulic Fracturing in the United States: A Summary of the Literature.'' Ecological Economics 138:160–167.

[89] This analysis compared the benefits estimated using full-form photochemical air quality modeling simulations (CMAQ and CAMx) against four reduced-form tools, including: InMAP; AP2/3; EASIUR and the EPA's benefit-per-ton.

[90] 85 FR 23823 (April 29, 2020).

reductions) minus the costs (forgone domestic climate benefits).

TABLE 6—SUMMARY OF THE PRESENT VALUE AND EQUIVALENT ANNUALIZED VALUE OF THE MONETIZED FORGONE BENEFITS, COST REDUCTIONS, AND NET BENEFITS FROM 2021 TO 2030, 7-PERCENT AND 3-PERCENT DISCOUNT RATES

[Millions of 2016$]

	7-Percent discount rate		3-Percent discount rate	
	PV	EAV	PV	EAV
Benefits (Total Cost Reductions)	$750	$100	$950	$110
Compliance Cost Reductions	*800*	*110*	*1,000*	*110*
Forgone Value of Product Recovery	*44*	*5.9*	*57*	*6.5*
Costs (Forgone Domestic Climate Benefits)	19	2.5	71	8.1
Net Benefits	730	97	880	100
Non-monetized Forgone Benefits	Non-monetized climate impacts from increases in methane emissions. Health effects of $PM_{2.5}$ and ozone exposure from an increase of about 120,000 short tons of VOC from 2021 through 2030. Health effects of HAP exposure from an increase of about 4,700 short tons of HAP from 2021 through 2030. Health effects of ozone exposure from an increase of about 450,000 short tons of methane from 2021 through 2030. Visibility impairment. Vegetation effects.			

Note: Estimates are rounded to two significant digits and may not sum due to independent rounding.

B. Executive Order 13771: Reducing Regulations and Controlling Regulatory Costs

This action is considered an Executive Order 13771 deregulatory action. Details on the estimated cost reductions of this final rule can be found in the EPA's analysis of the potential costs and benefits associated with this action.

C. Paperwork Reduction Act (PRA)

The information collection activities in this rule have been submitted for approval to the OMB under the PRA. The Information Collection Request (ICR) document that the EPA prepared has been assigned EPA ICR number 2523.04, Control Number 2060–0721. 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.

A summary of the information collection activities previously submitted to the OMB for the final action titled ''Standards of Performance for Crude Oil and Natural Gas Facilities for which Construction, Modification, or Reconstruction Commenced After September 18, 2015'' (2016 NSPS subpart OOOOa), under the PRA, and assigned OMB Control Number 2060–0721, can be found at 81 FR 35890. You can find a copy of the 2016 ICR in the 2016 NSPS subpart OOOOa docket (EPA–HQ–OAR–2010–0505–7626). The EPA is revising the information collection activities as a result of the amendments in this final rule. You can find a copy of the revised ICR in the docket for this rule (EPA–HQ–OAR–2017–0483), and it is briefly summarized here.

Comments were received on the October 15, 2018 (83 FR 52056) proposed rulemaking indicating that the recordkeeping and reporting burden for the 2016 NSPS subpart OOOOa was significantly underestimated, as discussed in section V.B.2 of this preamble. After consideration of these comments, the EPA updated the assessment of the recordkeeping and reporting burden for the 2016 NSPS subpart OOOOa. The updated 2016 NSPS subpart OOOOa ICR was used as the ''baseline'' from which changes in the Review Rule published in the **Federal Register** of Monday, September 14, 2020 were compared. Additional information on the Review Rule can be found at Docket ID No. EPA–HQ–OAR–2017–0757.

This final rule includes additional revisions to the information collection activities for NSPS subpart OOOOa.

Respondents/affected entities: Owners or operators of onshore oil and natural gas affected facilities.

Respondent's obligation to respond: Mandatory.

Estimated number of respondents: 519.

Frequency of response: Annually or semiannually, depending on the requirement.

Total estimated burden: 1,124,965 hours. Burden is defined at 5 CFR 1320.3(b).

Total estimated cost: $215,874,903, includes $2,681,370 annualized capital or operation and maintenance costs.

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.

D. Regulatory Flexibility Act (RFA)

I certify that this action will not have a significant economic impact on a substantial number of small entities under the RFA. In making this determination, the impact of concern is any significant adverse economic impact on small entities. An agency may certify that a rule will not have a significant economic impact on a substantial number of small entities if the rule relieves regulatory burden, has no net burden, or otherwise has a positive economic effect on the small entities subject to the rule. This is a deregulatory action, and the burden on all entities affected by this final rule, including small entities, is reduced compared to the 2016 NSPS subpart

OOOOa. See the RIA for details. We have, therefore, concluded that this action will relieve regulatory burden for all directly regulated small entities.

E. Unfunded Mandates Reform Act (UMRA)

This action does not contain any unfunded mandate as described in UMRA, 2 U.S.C. 1531–1538, and does not significantly or uniquely affect small governments. The action imposes no enforceable duty on any state, local, or tribal governments, or the private sector.

F. Executive Order 13132: Federalism

This action does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the National Government and the states, or on the distribution of power and responsibilities among the various levels of government.

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

This action does not have tribal implications, as specified in Executive Order 13175. It will not have substantial direct effects on tribal governments, on the relationship between the Federal Government and Indian tribes, or on the distribution of power and responsibilities between the Federal Government and Indian tribes, as specified in Executive Order 13175. Thus, Executive Order 13175 does not apply to this action.

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

This action is not subject to Executive Order 13045 because the EPA does not believe the environmental health risks or safety risks addressed by this action present a disproportionate risk to children. While children may experience forgone benefits as a result of this action, the potential forgone emission reductions (and related benefits) from the final amendments are small compared to the overall emission reductions (and related benefits) from the 2016 NSPS subpart OOOOa.

This final action does not affect the level of public health and environmental protection already being provided by existing NAAQS and other mechanisms in the CAA. This action does not affect applicable local, state, or Federal permitting or air quality management programs that will continue to address areas with degraded air quality and maintain the air quality in areas meeting current standards. Areas that need to reduce criteria air pollution to meet the NAAQS will still need to rely on control strategies to reduce emissions. The EPA does not believe this decrease in emission reductions projected from this action will have a disproportionate adverse effect on children's health.

I. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

This 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. In the RIA accompanying the 2016 NSPS subpart OOOOa, the EPA used the NEMS to estimate the impacts of the 2016 NSPS subpart OOOOa on the United States energy system. The EPA estimated small impacts of that rule over the 2020 to 2025 period relative to the baseline for that rule. This final rule is estimated to result in a decrease in total compliance costs, with the reduction in costs affecting a subset of the affected entities under NSPS subpart OOOOa. Therefore, the EPA expects that this deregulatory action will reduce the impacts estimated for the final NSPS in the 2016 RIA and, as such, is not a significant energy action.

J. National Technology Transfer and Advancement Act (NTTAA)

This action involves technical standards.[91] Therefore, the EPA conducted searches for the Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Reconsideration through the Enhanced National Standards Systems Network (NSSN) Database managed by the American National Standards Institute (ANSI). Searches were conducted for EPA Methods 1, 1A, 2, 2A, 2C, 2D, 3A, 3B, 3C, 4, 6, 10, 15, 16, 16A, 18, 21, 22, and 25A of 40 CFR part 60, appendix A. No applicable voluntary consensus standards (VCS) were identified for EPA Methods 1A, 2A, 2D, 21, and 22 and none were brought to its attention in comments. All potential standards were reviewed to determine the practicality of the VCS for this rule.

Two VCS were identified as an acceptable alternative to the EPA test methods for the purpose of this rule. First, ANSI/ASME PTC 19–10–1981, ''Flue and Exhaust Gas Analyses (Part 10),'' was identified to be used in lieu of EPA Methods 3B, 6, 6A, 6B, 15A, and 16A manual portions only and not the instrumental portion. This standard includes manual and instructional methods of analysis for carbon dioxide, carbon monoxide, hydrogen sulfide, nitrogen oxides, oxygen, and SO_2. Second, ASTM D6420–99 (2010), ''Test Method for Determination of Gaseous Organic Compounds by Direct Interface Gas Chromatography/Mass Spectrometry,'' is an acceptable alternative to EPA Method 18 with the following caveats; only use when the target compounds are all known and the target compounds are all listed in ASTM D6420 as measurable. ASTM D6420 should never be specified as a total VOC Method. (ASTM D6420–99 (2010) is not incorporated by reference in 40 CFR part 60.) The search identified 19 VCS that were potentially applicable for this rule in lieu of the EPA reference methods. However, these have been determined to not be practical due to lack of equivalency, documentation, validation of data, and other important technical and policy considerations. For additional information, please see the memorandum, ''Voluntary Consensus Standard Results for Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Reconsideration,'' located at Docket ID No. EPA–HQ–OAR–2017–0483.

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

The EPA believes that this action does not have disproportionately high and adverse human health or environmental effects on minority populations, low-income populations, and/or indigenous peoples, as specified in Executive Order 12898 (59 FR 7629, February 16, 1994). While these communities may experience forgone benefits as a result of this action, the potential forgone emission reductions (and related benefits) from the final amendments are small compared to the overall emission reductions (and related benefits) from the 2016 NSPS subpart OOOOa. The amendments in this final action will decrease the projected emission reductions of the rule it revises by a small degree. Based on the revisions in this final rule, for the year 2025, we estimate a decrease in the projected emissions reductions anticipated by the 2016 NSPS subpart OOOOa in the production and processing segments of about 12 to 15 percent for methane and about 7 to 9 percent for VOC.

[91] These technical standards are the same as those previously finalized at 40 CFR part 60, subpart OOOOa (81 FR 35824). 2016 NSPS subpart OOOOa also previously incorporated by reference 10 technical standards. The incorporation by reference remains unchanged in this action. See Docket ID Item Nos. EPA–HQ–OAR–2010–0505–7657 and EPA–HQ–OAR–2010–0505–7658.

Moreover, this action does not affect the level of public health and environmental protection already being provided by existing NAAQS, including ozone and $PM_{2.5}$, and other mechanisms in the CAA. This action does not affect applicable local, state, or Federal permitting or air quality management programs that will continue to address areas with degraded air quality and maintain the air quality in areas meeting current standards. Areas that need to reduce criteria air pollution to meet the NAAQS will still need to rely on control strategies to reduce emissions.

L. Congressional Review Act (CRA)

This action is subject to the CRA, and the EPA will submit a rule report to each House of the Congress and to the Comptroller General of the United States. This action is a ''major rule'' as defined by 5 U.S.C. 804(2).

List of Subjects in 40 CFR Part 60

Environmental protection, Administrative practice and procedure, Air pollution control, Reporting and recordkeeping.

Andrew Wheeler,

Administrator.

For the reasons set out in the preamble, 40 CFR part 60 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.*

Subpart OOOOa—Standards of Performance for Crude Oil and Natural Gas Facilities for Which Construction, Modification or Reconstruction Commenced After September 18, 2015

■ 2. Section 60.5360a is amended by revising paragraph (a) to read as follows:

§ 60.5360a What is the purpose of this subpart?

(a) This subpart establishes emission standards and compliance schedules for the control of volatile organic compounds (VOC) and sulfur dioxide (SO_2) emissions from affected facilities in the crude oil and natural gas production source category that commence construction, modification, or reconstruction after September 18, 2015.

* * * * *

■ 3. Section 60.5365a is amended by revising paragraphs (e), (f) introductory text, (g) introductory text, and (g)(1) and adding paragraph (i)(4) to read as follows:

§ 60.5365a Am I subject to this subpart?

* * * * *

(e) Each storage vessel affected facility, which is a single storage vessel as specified in paragraph (e)(1), (2), or (3) of this section.

(1) A single storage vessel that commenced construction, reconstruction, or modification after September 18, 2015, and on or before November 16, 2020, is a storage vessel affected facility if its potential for VOC emissions is equal to or greater than 6 tons per year (tpy) as determined according to this paragraph (e)(1). The potential for VOC emissions must be calculated using a generally accepted model or calculation methodology, based on the maximum average daily throughput (as defined in § 60.5430a) determined for a 30-day period prior to the applicable emission determination deadline specified in paragraphs (e)(2)(i) and (ii) of this section, except as provided in paragraph (e)(5)(iv). The determination may take into account requirements under a legally and practicably enforceable limit in an operating permit or other requirement established under a Federal, state, local, or tribal authority.

(2) Except as specified in paragraph (e)(3) of this section, a single storage vessel that commenced construction, reconstruction or modification after November 16, 2020, is a storage vessel affected facility if the potential for VOC emissions is equal to or greater than 6 tpy as determined according to paragraph (e)(2)(i) or (ii) of this section, except as provided in paragraph (e)(5)(iv) of this section. The determination may take into account requirements under a legally and practicably enforceable limit in an operating permit or other requirement established under a Federal, state, local, or tribal authority. The potential for VOC emissions is calculated on an individual storage vessel basis and is not averaged across the number of storage vessels at the site.

(i) For each storage vessel receiving liquids pursuant to the standards for well affected facilities in § 60.5375a, including wells subject to § 60.5375a(f), you must determine the potential for VOC emissions within 30 days after startup of production of the well, except as provided in paragraph (e)(5)(iv) of this section. The potential for VOC emissions must be calculated for each individual storage vessel using a generally accepted model or calculation methodology, based on the maximum average daily throughput, as defined in § 60.5430a, determined for a 30-day period of production.

(ii) For each storage vessel located at a compressor station or onshore natural gas processing plant, you must determine the potential for VOC emissions prior to startup of the compressor station or onshore natural gas processing plant using either method described in paragraph (e)(2)(ii)(A) or (B) of this section.

(A) Determine the potential for VOC emissions using a generally accepted model or calculation methodology and based on the throughput established in a legally and practicably enforceable limit in an operating permit or other requirement established under a Federal, state, local, or tribal authority; or

(B) Determine the potential for VOC emissions using a generally accepted model or calculation methodology and based on projected maximum average daily throughput. Maximum average daily throughput is determined using a generally accepted engineering model (*e.g.,* volumetric condensate rates from the storage vessels based on the maximum gas throughput capacity of each producing facility) to project the maximum average daily throughput for the storage vessel.

(3) If a storage vessel battery, which consists of two or more storage vessels, meets all of the design and operational criteria specified in paragraphs (e)(3)(i) through (iv) of this section through legally and practicably enforceable standards in a permit or other requirement established under Federal, state, local, or tribal authority, then each storage vessel in such storage vessel battery is a storage vessel affected facility.

(i) The storage vessels must be manifolded together with piping such that all vapors are shared among the headspaces of the storage vessels;

(ii) The storage vessels must be equipped with a closed vent system that is designed, operated, and maintained to route the vapors back to the process or to a control device;

(iii) The vapors collected in paragraph (e)(3)(i) of this section must be routed back to the process or to a control device that reduces VOC emissions by at least 95.0 percent; and

(iv) The VOC emissions, averaged across the number of storage vessels in the battery meeting all of the criteria of paragraphs (e)(3)(i) through (iii) of this section, are equal to or greater than 6 tpy.

(v) If a storage vessel battery meeting all of the criteria specified in paragraphs (e)(3)(i) through (iii) of this section through legally and practicably enforceable standards in a permit or other requirements established under Federal, state, local, or tribal authority, emits less than 6 tpy of VOC emissions averaged across the number of storage vessels in the battery, none of the storage vessels in the battery are storage vessel affected facilities.

(4) A storage vessel affected facility that subsequently has its potential for VOC emissions decrease to less than 6 tpy shall remain an affected facility under this subpart.

(5) For storage vessels not subject to a legally and practically enforceable limit in an operating permit or other requirement established under Federal, state, local, or tribal authority, any vapor from the storage vessel that is recovered and routed to a process through a VRU designed and operated as specified in this section is not required to be included in the determination of potential for VOC emissions for purposes of determining affected facility status, provided you comply with the requirements in paragraphs (e)(5)(i) through (iv) of this section.

(i) You meet the cover requirements specified in § 60.5411a(b).

(ii) You meet the closed vent system requirements specified in § 60.5411a(c) and (d).

(iii) You must maintain records that document compliance with paragraphs (e)(5)(i) and (ii) of this section.

(iv) In the event of removal of apparatus that recovers and routes vapor to a process, or operation that is inconsistent with the conditions specified in paragraphs (e)(5)(i) and (ii) of this section, you must determine the storage vessel's potential for VOC emissions according to this section within 30 days of such removal or operation.

(6) The requirements of this paragraph (e)(6) apply to each storage vessel affected facility immediately upon startup, startup of production, or return to service. A storage vessel affected facility that is reconnected to the original source of liquids is a storage vessel affected facility subject to the same requirements that applied before being removed from service. Any storage vessel that is used to replace any storage vessel affected facility is subject to the same requirements that applied to the storage vessel affected facility being replaced.

(7) A storage vessel with a capacity greater than 100,000 gallons used to recycle water that has been passed through two stage separation is not a storage vessel affected facility.

(f) The group of all equipment within a process unit at an onshore natural gas processing plant is an affected facility.

* * * * *

(g) Sweetening units located at onshore natural gas processing plants that commenced construction, modification, or reconstruction after September 18, 2015, and on or before November 16, 2020, and sweetening units that commence construction, modification, or reconstruction after November 16, 2020.

(1) Each sweetening unit that processes natural gas produced from either onshore or offshore wells is an affected facility; and

* * * * *

(i) * * *

(4) For purposes of § 60.5397a, a ''modification'' to an existing source separate tank battery surface site occurs when:

(i) Any of the actions in paragraphs (i)(3)(i) through (iii) of this section occurs at an existing source separate tank battery surface site;

(ii) A well sending production to an existing source separate tank battery site is modified, as defined in paragraphs (i)(3)(i) through (iii) of this section; or

(iii) A well site subject to the requirements in § 60.5397a removes all major production and processing equipment, as defined in § 60.5430a, such that it becomes a wellhead only well site and sends production to an existing source separate tank battery surface site.

* * * * *

■ 4. Section 60.5375a is amended by revising paragraphs (a)(1)(i), (a)(1)(iii) introductory text, and (f)(3)(ii) and adding paragraph (f)(4) to read as follows:

§ 60.5375a What VOC standards apply to well affected facilities?

* * * * *

(a) * * *

(1) * * *

(i) During the initial flowback stage, route the flowback into one or more well completion vessels or storage vessels and commence operation of a separator unless it is technically infeasible for a separator to function. The separator may be a production separator, but the production separator also must be designed to accommodate flowback. Any gas present in the initial flowback stage is not subject to control under this section.

* * * * *

(iii) You must have the separator onsite or otherwise available for use at a centralized facility or well pad that services the well affected facility during well completions. The separator must be available and ready for use to comply with paragraph (a)(1)(ii) of this section during the entirety of the flowback period, except as provided in paragraphs (a)(1)(iii)(A) through (C) of this section.

* * * * *

(f) * * *

(3) * * *

(ii) Route all flowback into one or more well completion vessels and commence operation of a separator unless it is technically infeasible for a separator to function. Any gas present in the flowback before the separator can function is not subject to control under this section. Capture and direct recovered gas to a completion combustion device, except in conditions that may result in a fire hazard or explosion, or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost, or waterways. Completion combustion devices must be equipped with a reliable continuous pilot flame.

(4) You must submit the notification as specified in § 60.5420a(a)(2), submit annual reports as specified in § 60.5420a(b)(1) and (2) and maintain records specified in § 60.5420a(c)(1)(iii) for each wildcat and delineation well. You must submit the notification as specified in § 60.5420a(a)(2), submit annual reports as specified in § 60.5420a(b)(1) and (2), and maintain records as specified in § 60.5420a(c)(1)(iii) and (vii) for each low pressure well.

* * * * *

■ 5. Section 60.5385a is amended by revising paragraph (a)(1) to read as follows:

§ 60.5385a What VOC standards apply to reciprocating compressor affected facilities?

* * * * *

(a) * * *

(1) On or before the compressor has operated for 26,000 hours. The number of hours of operation must be continuously monitored beginning upon initial startup of your reciprocating compressor affected facility, August 2, 2016, or the date of the most recent reciprocating compressor rod packing replacement, whichever is latest.

* * * * *

■ 6. Section 60.5393a is amended by revising paragraphs (b) and (c) and removing paragraph (f) to read as follows:

§ 60.5393a What VOC standards apply to pneumatic pump affected facilities?

* * * * *

(b) For each pneumatic pump affected facility at a well site you must reduce natural gas emissions by 95.0 percent, except as provided in paragraphs (b)(3), (4), and (5) of this section.

(1)–(2) [Reserved]

(3) You are not required to install a control device solely for the purpose of complying with the 95.0 percent reduction requirement of paragraph (b) of this section. If you do not have a control device installed on site by the compliance date and you do not have the ability to route to a process, then you must comply instead with the provisions of paragraphs (b)(3)(i) and (ii) of this section. For the purposes of this section, boilers and process heaters are not considered control devices. In addition, routing emissions from pneumatic pump discharges to boilers and process heaters is not considered routing to a process.

(i) Submit a certification in accordance with § 60.5420a(b)(8)(i)(A) in your next annual report, certifying that there is no available control device or process on site and maintain the records in § 60.5420a(c)(16)(i) and (ii).

(ii) If you subsequently install a control device or have the ability to route to a process, you are no longer required to comply with paragraph (b)(3)(i) of this section and must submit the information in § 60.5420a(b)(8)(ii) in your next annual report and maintain the records in § 60.5420a(c)(16)(i), (ii), and (iii). You must be in compliance with the requirements of paragraph (b) of this section within 30 days of startup of the control device or within 30 days of the ability to route to a process.

(4) If the control device available on site is unable to achieve a 95-percent reduction and there is no ability to route the emissions to a process, you must still route the pneumatic pump affected facility's emissions to that control device. If you route the pneumatic pump affected facility to a control device installed on site that is designed to achieve less than a 95-percent reduction, you must submit the information specified in § 60.5420a(b)(8)(i)(C) in your next annual report and maintain the records in § 60.5420a(c)(16)(iii).

(5) If an owner or operator determines, through an engineering assessment, that routing a pneumatic pump to a control device or a process is technically infeasible, the requirements specified in paragraphs (b)(5)(i) through (iv) of this section must be met.

(i) The owner or operator shall conduct the assessment of technical infeasibility in accordance with the criteria in paragraph (b)(5)(iii) of this section and have it certified by either a qualified professional engineer or an in-house engineer with expertise on the design and operation of the pneumatic pump in accordance with paragraph (b)(5)(ii) of this section.

(ii) The following certification, signed and dated by the qualified professional engineer or in-house engineer, shall state: ''I certify that the assessment of technical infeasibility was prepared under my direction or supervision. I further certify that the assessment was conducted and this report was prepared pursuant to the requirements of § 60.5393a(b)(5)(iii). Based on my professional knowledge and experience, and inquiry of personnel involved in the assessment, the certification submitted herein is true, accurate, and complete.''

(iii) The assessment of technical infeasibility to route emissions from the pneumatic pump to an existing control device onsite or to a process shall include, but is not limited to, safety considerations, distance from the control device or process, pressure losses and differentials in the closed vent system, and the ability of the control device or process to handle the pneumatic pump emissions which are routed to them. The assessment of technical infeasibility shall be prepared under the direction or supervision of the qualified professional engineer or in-house engineer who signs the certification in accordance with paragraph (b)(5)(ii) of this section.

(iv) The owner or operator shall maintain the records specified in § 60.5420a(c)(16)(iv).

(6) If the pneumatic pump is routed to a control device or a process and the control device or process is subsequently removed from the location or is no longer available, you are no longer required to be in compliance with the requirements of paragraph (b) of this section, and instead must comply with paragraph (b)(3) of this section and report the change in the next annual report in accordance with § 60.5420a(b)(8)(ii).

(c) If you use a control device or route to a process to reduce emissions, you must connect the pneumatic pump affected facility through a closed vent system that meets the requirements of §§ 60.5411a(d) and (e), 60.5415a(b)(3), and 60.5416a(d).

* * * * *

■ 7. Section 60.5395a is amended by revising the introductory text to read as follows:

§ 60.5395a What VOC standards apply to storage vessel affected facilities?

Each storage vessel affected facility must comply with the VOC standards in this section, except as provided in paragraph (e) of this section.

* * * * *

■ 8. Section 60.5397a is amended by revising paragraphs (a), (c)(2), (c)(7)(i) introductory text, and (c)(8) introductory text, adding paragraph (c)(8)(iii), and revising paragraphs (d), (f), (g) introductory text, (g)(1), (2), and (5), and (h) to read as follows:

§ 60.5397a What fugitive emissions VOC standards apply to the affected facility which is the collection of fugitive emissions components at a well site and the affected facility which is the collection of fugitive emissions components at a compressor station?

* * * * *

(a) You must comply with paragraph (a)(1) of this section, unless your affected facility under § 60.5365a(i) (*i.e.,* the collection of fugitive emissions components at a well site) meets the conditions specified in either paragraph (a)(1)(i) or (ii) of this section. If your affected facility under § 60.5365a(i) (*i.e.,* the collection of fugitive emissions components at a well site) meets the conditions specified in either paragraph (a)(1)(i) or (ii) of this section, you must comply with either paragraph (a)(1) or (2) of this section.

(1) You must monitor all fugitive emission components, as defined in § 60.5430a, in accordance with paragraphs (b) through (g) of this section. You must repair all sources of fugitive emissions in accordance with paragraph (h) of this section. You must keep records in accordance with paragraph (i) of this section and report in accordance with paragraph (j) of this section. For purposes of this section, fugitive emissions are defined as any visible emission from a fugitive emissions component observed using optical gas imaging or an instrument reading of 500 parts per million (ppm) or greater using Method 21 of appendix A–7 to this part.

(i) *First 30-day production.* For the collection of fugitive emissions components at a well site, where the total production of the well site is at or below 15 barrels of oil equivalent (boe) per day for the first 30 days of production, according to § 60.5415a(j), you must comply with the provisions of either paragraph (a)(1) or (2) of this section. Except as provided in this paragraph (a)(1)(i), the calculation must be performed within 45 days of the end of the first 30 days of production. To convert gas production to equivalent barrels of oil, divide the cubic feet of gas produced by 6,000. For well sites that commenced construction, reconstruction, or modification between

October 15, 2019, and November 16, 2020, the owner or operator may use the records of the first 30 days of production after becoming subject to this subpart, if available, to determine if the total well site production is at or below 15 boe per day, provided this determination is completed by December 14, 2020.

(ii) *Well site production decline.* For the collection of fugitive emissions components at a well site, where, at any time, the total production of the well site is at or below 15 boe per day based on a rolling 12-month average, you must comply with the provisions of either paragraph (a)(1) or (2) of this section. To convert gas production to equivalent barrels of oil, divide the cubic feet of gas produced by 6,000.

(2) You must maintain the total production for the well site at or below 15 boe per day based on a rolling 12-month average, according to §§ 60.5410a(k) and 60.5415a(i), comply with the reporting requirements in § 60.5420a(b)(7)(i)(C), and the recordkeeping requirements in § 60.5420a(c)(15)(ii), until such time that you perform any of the actions in paragraphs (a)(2)(i) through (v) of this section. If any of the actions listed in paragraphs (a)(2)(i) through (v) of this section occur, you must comply with paragraph (a)(3) of this section.

(i) A new well is drilled at the well site;

(ii) A well at the well site is hydraulically fractured;

(iii) A well at the well site is hydraulically refractured;

(iv) A well at the well site is stimulated in any manner for the purpose of increasing production, including well workovers; or

(v) A well at the well site is shut-in for the purpose of increasing production from the well.

(3) You must determine the total production for the well site for the first 30 days after any of the actions listed in paragraphs (a)(2)(i) through (v) of this section is completed, according to § 60.5415a(j), comply with paragraph (a)(3)(i) or (ii) of this section, the reporting requirements in § 60.5420a(b)(7)(i)(C), and the recordkeeping requirements in § 60.5420a(c)(15)(iii).

(i) If the total production for the well site is at or below 15 boe per day for the first 30 days after the action is completed, according to § 60.5415a(j), you must either continue to comply with paragraph (a)(2) of this section or comply with paragraph (a)(1) of this section.

(ii) If the total production for the well site is greater than 15 boe per day for the first 30 days after the action is completed, according to § 60.5415a(j), you must comply with paragraph (a)(1) of this section and conduct an initial monitoring survey for the collection of fugitive emissions components at the well site in accordance with the same schedule as for modified well sites as specified in § 60.5397a(f)(1).

* * * * *

(c) * * *

(2) Technique for determining fugitive emissions (*i.e.,* Method 21 of appendix A–7 to this part or optical gas imaging meeting the requirements in paragraphs (c)(7)(i) through (vii) of this section).

* * * * *

(7) * * *

(i) Verification that your optical gas imaging equipment meets the specifications of paragraphs (c)(7)(i)(A) and (B) of this section. This verification is an initial verification, and may either be performed by the facility, by the manufacturer, or by a third party. For the purposes of complying with the fugitive emissions monitoring program with optical gas imaging, a fugitive emission is defined as any visible emissions observed using optical gas imaging.

* * * * *

(8) If you are using Method 21 of appendix A–7 of this part, your plan must also include the elements specified in paragraphs (c)(8)(i) through (iii) of this section. For the purposes of complying with the fugitive emissions monitoring program using Method 21 of appendix A–7 of this part a fugitive emission is defined as an instrument reading of 500 ppm or greater.

* * * * *

(iii) Procedures for calibration. The instrument must be calibrated before use each day of its use by the procedures specified in Method 21 of appendix A–7 of this part. At a minimum, you must also conduct precision tests at the interval specified in Method 21 of appendix A–7 of this part, Section 8.1.2, and a calibration drift assessment at the end of each monitoring day. The calibration drift assessment must be conducted as specified in paragraph (c)(8)(iii)(A) of this section. Corrective action for drift assessments is specified in paragraphs (c)(8)(iii)(B) and (C) of this section.

(A) Check the instrument using the same calibration gas that was used to calibrate the instrument before use. Follow the procedures specified in Method 21 of appendix A–7 of this part, Section 10.1, except do not adjust the meter readout to correspond to the calibration gas value. If multiple scales are used, record the instrument reading for each scale used. Divide the arithmetic difference of the initial and post-test calibration response by the corresponding calibration gas value for each scale and multiply by 100 to express the calibration drift as a percentage.

(B) If a calibration drift assessment shows a negative drift of more than 10 percent, then all equipment with instrument readings between the fugitive emission definition multiplied by (100 minus the percent of negative drift/divided by 100) and the fugitive emission definition that was monitored since the last calibration must be re-monitored.

(C) If any calibration drift assessment shows a positive drift of more than 10 percent from the initial calibration value, then, at the owner/operator's discretion, all equipment with instrument readings above the fugitive emission definition and below the fugitive emission definition multiplied by (100 plus the percent of positive drift/divided by 100) monitored since the last calibration may be re-monitored.

(d) Each fugitive emissions monitoring plan must include the elements specified in paragraphs (d)(1) through (3) of this section, at a minimum, as applicable.

(1) If you are using optical gas imaging, your plan must include procedures to ensure that all fugitive emissions components are monitored during each survey. Example procedures include, but are not limited to, a sitemap with an observation path, a written narrative of where the fugitive emissions components are located and how they will be monitored, or an inventory of fugitive emissions components.

(2) If you are using Method 21 of appendix A–7 of this part, your plan must include a list of fugitive emissions components to be monitored and method for determining the location of fugitive emissions components to be monitored in the field (*e.g.,* tagging, identification on a process and instrumentation diagram, etc.).

(3) Your fugitive emissions monitoring plan must include the written plan developed for all of the fugitive emissions components designated as difficult-to-monitor in accordance with paragraph (g)(3) of this section, and the written plan for fugitive emissions components designated as unsafe-to-monitor in accordance with paragraph (g)(4) of this section.

* * * * *

(f)(1) You must conduct an initial monitoring survey within 90 days of the startup of production, as defined in

§ 60.5430a, for each collection of fugitive emissions components at a new well site or by June 3, 2017, whichever is later. For a modified collection of fugitive emissions components at a well site, the initial monitoring survey must be conducted within 90 days of the startup of production for each collection of fugitive emissions components after the modification or by June 3, 2017, whichever is later. Notwithstanding the preceding deadlines, for each collection of fugitive emissions components at a well site located on the Alaskan North Slope, as defined in § 60.5430a, that starts up production between September and March, you must conduct an initial monitoring survey within 6 months of the startup of production for a new well site, within 6 months of the first day of production after a modification of the collection of fugitive emission components, or by the following June 30, whichever is latest.

(2) You must conduct an initial monitoring survey within 90 days of the startup of a new compressor station for each collection of fugitive emissions components at the new compressor station or by June 3, 2017, whichever is later. For a modified collection of fugitive emissions components at a compressor station, the initial monitoring survey must be conducted within 90 days of the modification or by June 3, 2017, whichever is later. Notwithstanding the preceding deadlines, for each collection of fugitive emissions components at a new compressor station located on the Alaskan North Slope that starts up between September and March, you must conduct an initial monitoring survey within 6 months of the startup date for new compressor stations, within 6 months of the modification, or by the following June 30, whichever is latest.

(g) A monitoring survey of each collection of fugitive emissions components at a well site or at a compressor station must be performed at the frequencies specified in paragraphs (g)(1) and (2) of this section, with the exceptions noted in paragraphs (g)(3) through (5) of this section.

(1) Except as provided in this paragraph (g)(1), a monitoring survey of each collection of fugitive emissions components at a well site must be conducted at least semiannually after the initial survey. Consecutive semiannual monitoring surveys must be conducted at least 4 months apart and no more than 7 months apart. A monitoring survey of each collection of fugitive emissions components at a well site located on the Alaskan North Slope must be conducted at least annually. Consecutive annual monitoring surveys must be conducted at least 9 months apart and no more than 13 months apart.

(2) Except as provided in this paragraph (g)(2), a monitoring survey of the collection of fugitive emissions components at a compressor station must be conducted at least semiannually after the initial survey. Consecutive semiannual monitoring surveys must be conducted at least 4 months apart and no more than 7 months apart. A monitoring survey of the collection of fugitive emissions components at a compressor station located on the Alaskan North Slope must be conducted at least annually. Consecutive annual monitoring surveys must be conducted at least 9 months apart and no more than 13 months apart.

* * * * *

(5) You are no longer required to comply with the requirements of paragraph (g)(1) of this section when the owner or operator removes all major production and processing equipment, as defined in § 60.5430a, such that the well site becomes a wellhead only well site. If any major production and processing equipment is subsequently added to the well site, then the owner or operator must comply with the requirements in paragraphs (f)(1) and (g)(1) of this section.

(h) Each identified source of fugitive emissions shall be repaired, as defined in § 60.5430a, in accordance with paragraphs (h)(1) and (2) of this section.

(1) A first attempt at repair shall be made no later than 30 calendar days after detection of the fugitive emissions.

(2) Repair shall be completed as soon as practicable, but no later than 30 calendar days after the first attempt at repair as required in paragraph (h)(1) of this section.

(3) If the repair is technically infeasible, would require a vent blowdown, a compressor station shutdown, a well shutdown or well shut-in, or would be unsafe to repair during operation of the unit, the repair must be completed during the next scheduled compressor station shutdown for maintenance, scheduled well shutdown, scheduled well shut-in, after a scheduled vent blowdown, or within 2 years, whichever is earliest. For purposes of this paragraph (h)(3), a vent blowdown is the opening of one or more blowdown valves to depressurize major production and processing equipment, other than a storage vessel.

(4) Each identified source of fugitive emissions must be resurveyed to complete repair according to the requirements in paragraphs (h)(4)(i) through (iv) of this section, to ensure that there are no fugitive emissions.

(i) The operator may resurvey the fugitive emissions components to verify repair using either Method 21 of appendix A–7 of this part or optical gas imaging.

(ii) For each repair that cannot be made during the monitoring survey when the fugitive emissions are initially found, a digital photograph must be taken of that component or the component must be tagged during the monitoring survey when the fugitives were initially found for identification purposes and subsequent repair. The digital photograph must include the date that the photograph was taken and must clearly identify the component by location within the site (*e.g.,* the latitude and longitude of the component or by other descriptive landmarks visible in the picture).

(iii) Operators that use Method 21 of appendix A–7 of this part to resurvey the repaired fugitive emissions components are subject to the resurvey provisions specified in paragraphs (h)(4)(iii)(A) and (B) of this section.

(A) A fugitive emissions component is repaired when the Method 21 instrument indicates a concentration of less than 500 ppm above background or when no soap bubbles are observed when the alternative screening procedures specified in section 8.3.3 of Method 21 of appendix A–7 of this part are used.

(B) Operators must use the Method 21 monitoring requirements specified in paragraph (c)(8)(ii) of this section or the alternative screening procedures specified in section 8.3.3 of Method 21 of appendix A–7 of this part.

(iv) Operators that use optical gas imaging to resurvey the repaired fugitive emissions components, are subject to the resurvey provisions specified in paragraphs (h)(4)(iv)(A) and (B) of this section.

(A) A fugitive emissions component is repaired when the optical gas imaging instrument shows no indication of visible emissions.

(B) Operators must use the optical gas imaging monitoring requirements specified in paragraph (c)(7) of this section.

* * * * *

■ 9. Section 60.5398a is revised to read as follows:

§ 60.5398a What are the alternative means of emission limitations for VOC from well completions, reciprocating compressors, the collection of fugitive emissions components at a well site and the collection of fugitive emissions components at a compressor station?

(a) If, in the Administrator's judgment, an alternative means of emission limitation will achieve a reduction in VOC emissions at least equivalent to the reduction in VOC emissions achieved under § 60.5375a, § 60.5385a, or § 60.5397a, the Administrator will publish, in the **Federal Register**, a notice permitting the use of that alternative means for the purpose of compliance with § 60.5375a, § 60.5385a, or § 60.5397a. The authority to approve an alternative means of emission limitation is retained by the Administrator and shall not be delegated to States under section 111(c) of the Clean Air Act (CAA).

(b) Any notice under paragraph (a) of this section must be published only after notice and an opportunity for a public hearing.

(c) Determination of equivalence to the design, equipment, work practice, or operational requirements of this section will be evaluated by the following guidelines:

(1) The applicant must provide information that is sufficient for demonstrating the alternative means of emission limitation achieves emission reductions that are at least equivalent to the emission reductions that would be achieved by complying with the relevant standards. At a minimum, the application must include the following information:

(i) Details of the specific equipment or components that would be included in the alternative.

(ii) A description of the alternative work practice, including, as appropriate, the monitoring method, monitoring instrument or measurement technology, and the data quality indicators for precision and bias.

(iii) The method detection limit of the technology, technique, or process and a description of the procedures used to determine the method detection limit. At a minimum, the applicant must collect, verify, and submit field data encompassing seasonal variations to support the determination of the method detection limit. The field data may be supplemented with modeling analyses, controlled test site data, or other documentation.

(iv) Any initial and ongoing quality assurance/quality control measures necessary for maintaining the technology, technique, or process, and the timeframes for conducting such measures.

(v) Frequency of measurements. For continuous monitoring techniques, the minimum data availability.

(vi) Any restrictions for using the technology, technique, or process.

(vii) Initial and continuous compliance procedures, including recordkeeping and reporting, if the compliance procedures are different than those specified in this subpart.

(2) For each technology, technique, or process for which a determination of equivalency is requested, the application must provide a demonstration that the emission reduction achieved by the alternative means of emission limitation is at least equivalent to the emission reduction that would be achieved by complying with the relevant standards in this subpart.

(d) Any alternative means of emission limitations approved under this section shall constitute a required work practice, equipment, design, or operational standard within the meaning of section 111(h)(1) of the CAA.

■ 10. Add § 60.5399a to read as follows:

§ 60.5399a What alternative fugitive emissions standards apply to the affected facility which is the collection of fugitive emissions components at a well site and the affected facility which is the collection of fugitive emissions components at a compressor station: Equivalency with state, local, and tribal programs?

This section provides alternative fugitive emissions standards based on programs under state, local, or tribal authorities for the collection of fugitive emissions components, as defined in § 60.5430a, located at well sites and compressor stations. Paragraphs (a) through (e) of this section outline the procedure for submittal and approval of alternative fugitive emissions standards. Paragraphs (f) through (n) provide approved alternative fugitive emissions standards. The terms ''fugitive emissions components'' and ''repaired'' are defined in § 60.5430a and must be applied to the alternative fugitive emissions standards in this section. The requirements for a monitoring plan as specified in § 60.5397a(c) and (d) apply to the alternative fugitive emissions standards in this section.

(a) *Alternative fugitive emissions standards.* If, in the Administrator's judgment, an alternative fugitive emissions standard will achieve a reduction in VOC emissions at least equivalent to the reductions achieved under § 60.5397a, the Administrator will publish, in the **Federal Register**, a notice permitting use of the alternative fugitive emissions standard for the purpose of compliance with § 60.5397a. The authority to approve alternative fugitive emissions standards is retained by the Administrator and shall not be delegated to States under section 111(c) of the CAA.

(b) *Notice.* Any notice under paragraph (a) of this section will be published only after notice and an opportunity for public hearing.

(c) *Evaluation guidelines.* Determination of alternative fugitive emissions standards to the design, equipment, work practice, or operational requirements of § 60.5397a will be evaluated by the following guidelines:

(1) The monitoring instrument, including the monitoring procedure;

(2) The monitoring frequency;

(3) The fugitive emissions definition;

(4) The repair requirements; and

(5) The recordkeeping and reporting requirements.

(d) *Approval of alternative fugitive emissions standard.* Any alternative fugitive emissions standard approved under this section shall:

(1) Constitute a required design, equipment, work practice, or operational standard within the meaning of section 111(h)(1) of the CAA; and

(2) Be made available for use by any owner or operator in meeting the relevant standards and requirements established for affected facilities under § 60.5397a.

(e) *Notification.* (1) An owner or operator must notify the Administrator of adoption of the alternative fugitive emissions standards within the first annual report following implementation of the alternative fugitive emissions standard, as specified in § 60.5420a(a)(3).

(2) An owner or operator implementing one of the alternative fugitive emissions standards must submit the reports specified in § 60.5420a(b)(7)(iii). An owner or operator must also maintain the records specified by the specific alternative fugitive emissions standard for a period of at least 5 years.

(f) *Alternative fugitive emissions requirements for the collection of fugitive emissions components located at a well site or a compressor station in the State of California.* An affected facility, which is the collection of fugitive emissions components, as defined in § 60.5430a, located at a well site or a compressor station in the State of California may elect to reduce VOC emissions through compliance with the monitoring, repair, and recordkeeping requirements in the California Code of Regulations, title 17, sections 95665–95667, effective January 1, 2020, as an alternative to complying with the requirements in § 60.5397a(f)(1) and (2), (g)(1) through (4), (h), and (i). The information specified in § 60.5420a(b)(7)(iii)(A) and the information specified in either § 60.5420a(b)(7)(iii)(B) or (C) may be provided as an alternative to the requirements in § 60.5397a(j).

(g) *Alternative fugitive emissions requirements for the collection of fugitive emissions components located at a well site or a compressor station in the State of Colorado.* An affected facility, which is the collection of fugitive emissions components, as defined in § 60.5430a, located at a well site or a compressor station in the State of Colorado may elect to comply with the monitoring, repair, and recordkeeping requirements in Colorado Regulation 7, Part D, section I.L or II.E, effective February 14, 2020, for well sites and compressor stations, as an alternative to complying with the requirements in § 60.5397a(f)(1) and (2), (g)(1) through (4), (h), and (i), provided the monitoring instrument used is an optical gas imaging or a Method 21 instrument (see appendix A–7 of this part). Monitoring must be conducted on at least a semiannual basis for well sites and compressor stations. If using the alternative in this paragraph (g), the information specified in § 60.5420a(b)(7)(iii)(A) and (C) must be provided in lieu of the requirements in § 60.5397a(j).

(h) *Alternative fugitive emissions requirements for the collection of fugitive emissions components located at a well site in the State of Ohio.* An affected facility, which is the collection of fugitive emissions components, as defined in § 60.5430a, located at a well site in the State of Ohio may elect to comply with the monitoring, repair, and recordkeeping requirements in Ohio General Permits 12.1, Section C.5 and 12.2, Section C.5, effective April 14, 2014, as an alternative to complying with the requirements in § 60.5397a(f)(1), (g)(1), (3), and (4), (h), and (i), provided the monitoring instrument used is optical gas imaging or a Method 21 instrument (see appendix A–7 of this part) with a leak definition and reading of 500 ppm or greater. Monitoring must be conducted on at least a semiannual basis and skip periods cannot be applied. The information specified in § 60.5420a(b)(7)(iii)(A) and the information specified in either § 60.5420a(b)(7)(iii)(B) or (C) may be provided as an alternative to the requirements in § 60.5397a(j).

(i) *Alternative fugitive emissions requirements for the collection of fugitive emissions components located at a compressor station in the State of Ohio.* An affected facility, which is the collection of fugitive emissions components, as defined in § 60.5430a, located at a compressor station in the State of Ohio may elect to comply with the monitoring, repair, and recordkeeping requirements in Ohio General Permit 18.1, effective February 7, 2017, as an alternative to complying with the requirements in § 60.5397a(f)(2), (g)(2) through (4), (h), and (i), provided the monitoring instrument used is optical gas imaging or a Method 21 instrument (see appendix A–7 of this part) with a leak definition and reading of 500 ppm or greater. Monitoring must be conducted on at least a semiannual basis and skip periods cannot be applied. The information specified in § 60.5420a(b)(7)(iii)(A) and the information specified in either § 60.5420a(b)(7)(iii)(B) or (C) may be provided as an alternative to the requirements in § 60.5397a(j).

(j) *Alternative fugitive emissions requirements for the collection of fugitive emissions components located at a well site in the State of Pennsylvania.* An affected facility, which is the collection of fugitive emissions components, as defined in § 60.5430a, located at a well site in the State of Pennsylvania may elect to comply with the monitoring, repair, and recordkeeping requirements in Pennsylvania General Permit 5A, section G, effective August 8, 2018, as an alternative to complying with the requirements in § 60.5397a(f)(2), (g)(2) through (4), (h), and (i), provided the monitoring instrument used is an optical gas imaging or a Method 21 instrument (see appendix A–7 of this part). The information specified in § 60.5420a(b)(7)(iii)(A) and the information specified in either § 60.5420a(b)(7)(iii)(B) or (C) may be provided as an alternative to the requirements in § 60.5397a(j).

(k) *Alternative fugitive emissions requirements for the collection of fugitive emissions components located at a compressor station in the State of Pennsylvania.* An affected facility, which is the collection of fugitive emissions components, as defined in § 60.5430a, located at a compressor station in the State of Pennsylvania may elect to comply with the monitoring, repair, and recordkeeping requirements in Pennsylvania General Permit 5, section G, effective August 8, 2018, as an alternative to complying with the requirements in § 60.5397a(f)(2), (g)(2) through (4), (h), and (i), provided the monitoring instrument used is an optical gas imaging or a Method 21 instrument (see appendix A–7 of this part). The information specified in § 60.5420a(b)(7)(iii)(A) and the information specified in either § 60.5420a(b)(7)(iii)(B) or (C) may be provided as an alternative to the requirements in § 60.5397a(j).

(l) *Alternative fugitive emissions requirements for the collection of fugitive emissions components located at a well site in the State of Texas.* An affected facility, which is the collection of fugitive emissions components, as defined in § 60.5430a, located at a well site in the State of Texas may elect to comply with the monitoring, repair, and recordkeeping requirements in the Air Quality Standard Permit for Oil and Gas Handling and Production Facilities, section (e)(6), effective November 8, 2012, or at 30 Texas Administrative Code section 116.620, effective September 4, 2000, as an alternative to complying with the requirements in § 60.5397a(f)(2), (g)(2) through (4), (h), and (i), provided the monitoring instrument used is optical gas imaging or a Method 21 instrument (see appendix A–7 of this part) with a leak definition and reading of 500 ppm or greater. Monitoring must be conducted on at least a semiannual basis and skip periods may not be applied. If using the requirement in this paragraph (l), the information specified in § 60.5420a(b)(7)(iii)(A) and (C) must be provided in lieu of the requirements in § 60.5397a(j).

(m) *Alternative fugitive emissions requirements for the collection of fugitive emissions components located at a compressor station in the State of Texas.* An affected facility, which is the collection of fugitive emissions components, as defined in § 60.5430a, located at a compressor in the State of Texas may elect to comply with the monitoring, repair, and recordkeeping requirements in the Air Quality Standard Permit for Oil and Gas Handling and Production Facilities, section (e)(6), effective November 8, 2012, or at 30 Texas Administrative Code section 116.620, effective September 4, 2000, as an alternative to complying with the requirements in § 60.5397a(f)(2), (g)(2) through (4), (h), and (i), provided the monitoring instrument used is optical gas imaging or a Method 21 instrument (see appendix A–7 of this part) with a leak definition and reading of 500 ppm or greater. Monitoring must be conducted on at least a semiannual basis and skip periods may not be applied. If using the alternative in this paragraph (m), the information specified in § 60.5420a(b)(7)(iii)(A) and (C) must be provided in lieu of the requirements in § 60.5397a(j).

(n) *Alternative fugitive emissions requirements for the collection of fugitive emissions components located at a well site in the State of Utah.* An affected facility, which is the collection of fugitive emissions components, as defined in § 60.5430a, and is required to control emissions in accordance with Utah Administrative Code R307–506 and R307–507, located at a well site in the State of Utah may elect to comply with the monitoring, repair, and recordkeeping requirements in the Utah Administrative Code R307–509, effective March 2, 2018, as an alternative to complying with the requirements in § 60.5397a(f)(2), (g)(2) through (4), (h), and (i). If using the alternative in this paragraph (n), the information specified in § 60.5420a(b)(7)(iii)(A) and (C) must be provided in lieu of the requirements in § 60.5397a(j).

■ 11. Section 60.5400a is amended by revising the introductory text and paragraph (a) to read as follows:

§ 60.5400a What equipment leak VOC standards apply to affected facilities at an onshore natural gas processing plant?

This section applies to the group of all equipment, except compressors, within a process unit located at an onshore natural gas processing plant.

(a) You must comply with the requirements of §§ 60.482–1a(a), (b), (d), and (e), 60.482–2a, and 60.482–4a through 60.482–11a, except as provided in § 60.5401a, as soon as practicable but no later than 180 days after the initial startup of the process unit.

* * * * *

■ 12. Section 60.5401a is amended by revising paragraphs (e) and (g) to read as follows:

§ 60.5401a What are the exceptions to the equipment leak VOC standards for affected facilities at onshore natural gas processing plants?

* * * * *

(e) Pumps in light liquid service, valves in gas/vapor and light liquid service, pressure relief devices in gas/vapor service, and connectors in gas/vapor service and in light liquid service within a process unit that is located in the Alaskan North Slope are exempt from the monitoring requirements of §§ 60.482–2a(a)(1), 60.482–7a(a), and 60.482–11a(a) and paragraph (b)(1) of this section.

* * * * *

(g) An owner or operator may use the following provisions instead of § 60.485a(b)(2): A calibration drift assessment shall be performed, at a minimum, at the end of each monitoring day. Check the instrument using the same calibration gas(es) that were used to calibrate the instrument before use. Follow the procedures specified in Method 21 of appendix A–7 of this part, Section 10.1, except do not adjust the meter readout to correspond to the calibration gas value. Record the instrument reading for each scale used as specified in § 60.486a(e)(8). For each scale, divide the arithmetic difference of the most recent calibration and the post-test calibration response by the corresponding calibration gas value, and multiply by 100 to express the calibration drift as a percentage. If any calibration drift assessment shows a negative drift of more than 10 percent from the most recent calibration response, then all equipment monitored since the last calibration with instrument readings below the appropriate leak definition and above the leak definition multiplied by (100 minus the percent of negative drift/divided by 100) must be re-monitored. If any calibration drift assessment shows a positive drift of more than 10 percent from the most recent calibration response, then, at the owner/operator's discretion, all equipment since the last calibration with instrument readings above the appropriate leak definition and below the leak definition multiplied by (100 plus the percent of positive drift/divided by 100) may be re-monitored.

■ 13. Section 60.5405a is amended by revising the section heading to read as follows:

§ 60.5405a What standards apply to sweetening unit affected facilities?

* * * * *

■ 14. Section 60.5406a is amended by revising the section heading to read as follows:

§ 60.5406a What test methods and procedures must I use for my sweetening unit affected facilities?

* * * * *

■ 15. Section 60.5407a is amended by revising the section heading and paragraph (a) introductory text to read as follows:

§ 60.5407a What are the requirements for monitoring of emissions and operations from my sweetening unit affected facilities?

(a) If your sweetening unit affected facility is subject to the provisions of § 60.5405a(a) or (b) you must install, calibrate, maintain, and operate monitoring devices or perform measurements to determine the following operations information on a daily basis:

* * * * *

■ 16. Section 60.5410a is amended by:

■ a. Revising the section heading, introductory text, and paragraphs (c)(1) and (e)(2) through (5);

■ b. Removing paragraph (e)(8);

■ c. Revising paragraphs (g) introductory text, (g)(3), (h), (j) introductory text, and (j)(1); and

■ d. Adding paragraph (k).

The revisions and addition read as follows:

§ 60.5410a How do I demonstrate initial compliance with the standards for my well, centrifugal compressor, reciprocating compressor, pneumatic controller, pneumatic pump, storage vessel, collection of fugitive emissions components at a well site, collection of fugitive emissions components at a compressor station, and equipment leaks at onshore natural gas processing plants and sweetening unit affected facilities?

You must determine initial compliance with the standards for each affected facility using the requirements in paragraphs (a) through (k) of this section. Except as otherwise provided in this section, the initial compliance period begins on August 2, 2016, or upon initial startup, whichever is later, and ends no later than 1 year after the initial startup date for your affected facility or no later than 1 year after August 2, 2016. The initial compliance period may be less than 1 full year.

* * * * *

(c) * * *

(1) If complying with § 60.5385a(a)(1) or (2), during the initial compliance period, you must continuously monitor the number of hours of operation or track the number of months since initial startup, since August 2, 2016, or since the last rod packing replacement, whichever is latest.

* * * * *

(e) * * *

(2) If you own or operate a pneumatic pump affected facility located at a well site, you must reduce emissions in accordance with § 60.5393a(b)(1) or (2), and you must collect the pneumatic pump emissions through a closed vent system that meets the requirements of § 60.5411a(d) and (e).

(3) If you own or operate a pneumatic pump affected facility located at a well site and there is no control device or process available on site, you must submit the certification in § 60.5420a(b)(8)(i)(A).

(4) If you own or operate a pneumatic pump affected facility located at a well

site, and you are unable to route to an existing control device or to a process due to technical infeasibility, you must submit the certification in § 60.5420a(b)(8)(i)(B).

(5) If you own or operate a pneumatic pump affected facility located at a well site and you reduce emissions in accordance with § 60.5393a(b)(4), you must collect the pneumatic pump emissions through a closed vent system that meets the requirements of § 60.5411a(d) and (e).

* * * * *

(g) For sweetening unit affected facilities, initial compliance is demonstrated according to paragraphs (g)(1) through (3) of this section.

* * * * *

(3) You must submit the results of paragraphs (g)(1) and (2) of this section in the initial annual report submitted for your sweetening unit affected facilities.

(h) For each storage vessel affected facility you must comply with paragraphs (h)(1) through (6) of this section. Except as otherwise provided in this paragraph (h), you must demonstrate initial compliance by August 2, 2016, or within 60 days after startup, whichever is later.

(1) You must determine the potential VOC emission rate as specified in § 60.5365a(e).

(2) You must reduce VOC emissions in accordance with § 60.5395a(a).

(3) If you use a control device to reduce emissions, you must equip the storage vessel with a cover that meets the requirements of § 60.5411a(b) and is connected through a closed vent system that meets the requirements of § 60.5411a(c) and (d) to a control device that meets the conditions specified in § 60.5412a(d) within 60 days after startup for storage vessels constructed, modified, or reconstructed at well sites with no other wells in production, or upon startup for storage vessels constructed, modified, or reconstructed at well sites with one or more wells already in production.

(4) You must conduct an initial performance test as required in § 60.5413a within 180 days after initial startup or within 180 days of August 2, 2016, whichever is later, and you must comply with the continuous compliance requirements in § 60.5415a(e).

(5) You must submit the information required for your storage vessel affected facility in your initial annual report as specified in § 60.5420a(b)(1) and (6).

(6) You must maintain the records required for your storage vessel affected facility, as specified in § 60.5420a(c)(5) through (8), (12) through (14), and (17), as applicable, for each storage vessel affected facility.

* * * * *

(j) To achieve initial compliance with the fugitive emission standards for each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a compressor station you must comply with paragraphs (j)(1) through (5) of this section.

(1) You must develop a fugitive emissions monitoring plan as required in § 60.5397a(b), (c), and (d).

* * * * *

(k) To demonstrate initial compliance with the requirement to maintain the total well site production at or below 15 boe per day based on a rolling 12-month average, as specified in § 60.5397a(a)(2), you must comply with paragraphs (k)(1) through (3) of this section.

(1) You must demonstrate that the total daily combined oil and natural gas production for all wells at the well site is at or below 15 boe per day, based on a 12-month average from the previous 12 months of operation, according to paragraphs (k)(1)(i) through (iii) of this section within 45 days of the end of each month. The rolling 12-month average of the total well site production determined according to paragraph (k)(1)(iii) of this section must be at or below 15 boe per day.

(i) Determine the daily combined oil and natural gas production for each individual well at the well site for the month. To convert gas production to equivalent barrels of oil, divide the cubic feet of gas produced by 6,000.

(ii) Sum the daily production for each individual well at the well site to determine the total well site production and divide by the number of days in the month. This is the average daily total well site production for the month.

(iii) Use the result determined in paragraph (k)(1)(ii) of this section and average with the daily total well site production values determined for each of the preceding 11 months to calculate the rolling 12-month average of the total well site production.

(2) You must maintain records as specified in § 60.5420a(c)(15)(ii).

(3) You must submit compliance information in the initial and subsequent annual reports as specified in § 60.5420a(b)(7)(i)(C) and (b)(7)(iv).

■ 17. Section 60.5411a is amended by revising the introductory text and paragraphs (a) introductory text, (a)(1), (c)(1) and (2), (d)(1), and (e) to read as follows:

§ 60.5411a What additional requirements must I meet to determine initial compliance for my covers and closed vent systems routing emissions from centrifugal compressor wet seal fluid degassing systems, reciprocating compressors, pneumatic pumps and storage vessels?

You must meet the applicable requirements of this section for each cover and closed vent system used to comply with the emission standards for your centrifugal compressor wet seal degassing systems, reciprocating compressors, pneumatic pumps, and storage vessels.

(a) Closed vent system requirements for reciprocating compressors and centrifugal compressor wet seal degassing systems.

(1) You must design the closed vent system to route all gases, vapors, and fumes emitted from the reciprocating compressor rod packing emissions collection system to a process. You must design the closed vent system to route all gases, vapors, and fumes emitted from the centrifugal compressor wet seal fluid degassing system to a process or a control device that meets the requirements specified in § 60.5412a(a) through (c).

* * * * *

(c) * * *

(1) You must design the closed vent system to route all gases, vapors, and fumes emitted from the material in the storage vessel affected facility to a control device that meets the requirements specified in § 60.5412a(c) and (d), or to a process.

(2) You must design and operate a closed vent system with no detectable emissions, as determined using olfactory, visual, and auditory inspections or optical gas imaging inspections as specified in § 60.5416a(c).

* * * * *

(d) * * *

(1) You must conduct an assessment that the closed vent system is of sufficient design and capacity to ensure that all emissions from the affected facility are routed to the control device and that the control device is of sufficient design and capacity to accommodate all emissions from the affected facility, and have it certified by a qualified professional engineer or an in-house engineer with expertise on the design and operation of the closed vent system in accordance with paragraphs (d)(1)(i) and (ii) of this section.

(i) You must provide the following certification, signed and dated by a qualified professional engineer or an in-house engineer: ‘‘I certify that the closed vent system design and capacity assessment was prepared under my direction or supervision. I further certify that the closed vent system design and capacity assessment was conducted and this report was prepared pursuant to the requirements of subpart OOOOa of 40 CFR part 60. Based on my professional knowledge and experience, and inquiry of personnel involved in the assessment, the certification submitted herein is true, accurate, and complete.''

(ii) The assessment shall be prepared under the direction or supervision of a qualified professional engineer or an in-house engineer who signs the certification in paragraph (d)(1)(i) of this section.

* * * * *

(e) Closed vent system requirements for pneumatic pump affected facilities using a control device or routing emissions to a process.

(1) You must design the closed vent system to route all gases, vapors, and fumes emitted from the pneumatic pump to a control device or a process.

(2) You must design and operate a closed vent system with no detectable emissions, as demonstrated by § 60.5416a(b), olfactory, visual, and auditory inspections or optical gas imaging inspections as specified in § 60.5416a(d).

(3) You must meet the requirements specified in paragraphs (e)(3)(i) and (ii) of this section if the closed vent system contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the control device or to a process.

(i) Except as provided in paragraph (e)(3)(ii) of this section, you must comply with either paragraph (e)(3)(i)(A) or (B) of this section for each bypass device.

(A) You must properly install, calibrate, maintain, and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere that sounds an alarm, or initiates notification via remote alarm to the nearest field office, when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere. You must maintain records of each time the alarm is activated according to § 60.5420a(c)(8).

(B) You must secure the bypass device valve installed at the inlet to the bypass device in the non-diverting position using a car-seal or a lock-and-key type configuration.

(ii) Low leg drains, high point bleeds, analyzer vents, open-ended valves or lines, and safety devices are not subject to the requirements of paragraph (e)(3)(i) of this section.

■ 18. Section 60.5412a is amended by revising paragraphs (a)(1) introductory text, (a)(1)(iv), (c) introductory text, (d)(1)(iv) introductory text, and (d)(1)(iv)(D) to read as follows:

§ 60.5412a What additional requirements must I meet for determining initial compliance with control devices used to comply with the emission standards for my centrifugal compressor, and storage vessel affected facilities?

* * * * *

(a) * * *

(1) Each combustion device (*e.g.,* thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) must be designed and operated in accordance with one of the performance requirements specified in paragraphs (a)(1)(i) through (iv) of this section. If a boiler or process heater is used as the control device, then you must introduce the vent stream into the flame zone of the boiler or process heater.

* * * * *

(iv) You must introduce the vent stream with the primary fuel or use the vent stream as the primary fuel in a boiler or process heater.

* * * * *

(c) For each carbon adsorption system used as a control device to meet the requirements of paragraph (a)(2) or (d)(2) of this section, you must manage the carbon in accordance with the requirements specified in paragraphs (c)(1) and (2) of this section.

* * * * *

(d) * * *

(1) * * *

(iv) Each enclosed combustion control device (*e.g.,* thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) must be designed and operated in accordance with one of the performance requirements specified in paragraphs (d)(1)(iv)(A) through (D) of this section. If a boiler or process heater is used as the control device, then you must introduce the vent stream into the flame zone of the boiler or process heater.

* * * * *

(D) You must introduce the vent stream with the primary fuel or use the vent stream as the primary fuel in a boiler or process heater.

* * * * *

■ 19. Section 60.5413a is amended by revising paragraphs (d)(5)(i) introductory text, (d)(9)(iii), and (d)(12) introductory text to read as follows:

§ 60.5413a What are the performance testing procedures for control devices used to demonstrate compliance at my centrifugal compressor and storage vessel affected facilities?

* * * * *

(d) * * *

(5) * * *

(i) At the inlet gas sampling location, securely connect a fused silica-coated stainless steel evacuated canister fitted with a flow controller sufficient to fill the canister over a 3-hour period. Filling must be conducted as specified in paragraphs (d)(5)(i)(A) through (C) of this section.

* * * * *

(9) * * *

(iii) A 0–10 parts per million by volume-wet (ppmvw) (as propane) measurement range is preferred; as an alternative a 0–30 ppmvw (as propane) measurement range may be used.

* * * * *

(12) The owner or operator of a combustion control device model tested under this paragraph (d)(12) must submit the information listed in paragraphs (d)(12)(i) through (vi) of this section for each test run in the test report required by this section in accordance with § 60.5420a(b)(10). Owners or operators who claim that any of the performance test information being submitted is confidential business information (CBI) must submit a complete file including information claimed to be CBI, on a compact disc, flash drive, or other commonly used electronic storage media to the EPA. The electronic media must be clearly marked as CBI and mailed to Attn: CBI Document Control Officer; Office of Air Quality Planning and Standards (OAQPS), Room 521; 109 T.W. Alexander Drive; Research Triangle Park, NC 27711. The same file with the CBI omitted must be submitted to *Oil_and_Gas_PT@EPA.GOV.*

* * * * *

■ 20. Section 60.5415a is amended by:

■ a. Revising the section heading and paragraphs (b) introductory text and (b)(3);

■ b. Removing paragraph (b)(4);

■ c. Revising paragraphs (c)(1), (g) introductory text, (h) introductory text, and (h)(2); and

■ d. Adding paragraphs (i) and (j).

The revisions and additions read as follows:

§ 60.5415a How do I demonstrate continuous compliance with the standards for my well, centrifugal compressor, reciprocating compressor, pneumatic controller, pneumatic pump, storage vessel, collection of fugitive emissions components at a well site, and collection of fugitive emissions components at a compressor station affected facilities, equipment leaks at onshore natural gas processing plants and sweetening unit affected facilities?

* * * * *

(b) For each centrifugal compressor affected facility and each pneumatic pump affected facility, you must demonstrate continuous compliance according to paragraph (b)(3) of this section. For each centrifugal compressor affected facility, you also must demonstrate continuous compliance according to paragraphs (b)(1) and (2) of this section.

* * * * *

(3) You must submit the annual reports required by § 60.5420a(b)(1), (3), and (8) and maintain the records as specified in § 60.5420a(c)(2), (6) through (11), (16), and (17), as applicable.

* * * * *

(c) * * *

(1) You must continuously monitor the number of hours of operation for each reciprocating compressor affected facility or track the number of months since initial startup, since August 2, 2016, or since the date of the most recent reciprocating compressor rod packing replacement, whichever is latest.

* * * * *

(g) For each sweetening unit affected facility, you must demonstrate continuous compliance with the standards for SO_2 specified in § 60.5405a(b) according to paragraphs (g)(1) and (2) of this section.

* * * * *

(h) For each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a compressor station, you must demonstrate continuous compliance with the fugitive emission standards specified in § 60.5397a(a)(1) according to paragraphs (h)(1) through (4) of this section.

* * * * *

(2) You must repair each identified source of fugitive emissions as required in § 60.5397a(h).

* * * * *

(i) For each collection of fugitive emissions components at a well site complying with § 60.5397a(a)(2), you must demonstrate continuous compliance according to paragraphs (i)(1) through (4) of this section. You must perform the calculations shown in paragraphs (i)(1) through (4) of this section within 45 days of the end of each month. The rolling 12-month average of the total well site production determined according to paragraph (i)(4) of this section must be at or below 15 boe per day.

(1) Begin with the most recent 12-month average.

(2) Determine the daily combined oil and natural gas production of each individual well at the well site for the month. To convert gas production to equivalent barrels of oil, divide the cubic feet of gas produced by 6,000.

(3) Sum the daily production for each individual well at the well site and divide by the number of days in the month. This is the average daily total well site production for the month.

(4) Use the result determined in paragraph (i)(3) of this section and average with the daily total well site production values determined for each of the preceding 11 months to calculate the rolling 12-month average of the total well site production.

(j) To demonstrate that the well site produced at or below 15 boe per day for the first 30 days after startup of production as specified in § 60.5397a(3), you must calculate the daily production for each individual well at the well site during the first 30 days of production after completing any action listed in § 60.5397a(a)(2)(i) through (v) and sum the individual well production values to obtain the total well site production. The calculation must be performed within 45 days of the end of the first 30 days of production after completing any action listed in § 60.5397a(a)(2)(i) through (v). To convert gas production to equivalent barrels of oil, divide cubic feet of gas produced by 6,000.

■ 21. Section 60.5416a is amended by revising the introductory text and paragraphs (a) introductory text, (a)(4) introductory text, (b) introductory text, (c) introductory text, (c)(1), and (c)(2) introductory text, adding paragraph (c)(2)(iv), and revising paragraph (d) to read as follows:

§ 60.5416a What are the initial and continuous cover and closed vent system inspection and monitoring requirements for my centrifugal compressor, reciprocating compressor, pneumatic pump, and storage vessel affected facilities?

For each closed vent system or cover at your centrifugal compressor, reciprocating compressor, pneumatic pump, and storage vessel affected facilities, you must comply with the applicable requirements of paragraphs (a) through (d) of this section.

(a) *Inspections for closed vent systems and covers installed on each centrifugal compressor or reciprocating compressor affected facility.* Except as provided in paragraphs (b)(11) and (12) of this section, you must inspect each closed vent system according to the procedures and schedule specified in paragraphs (a)(1) and (2) of this section, inspect each cover according to the procedures and schedule specified in paragraph (a)(3) of this section, and inspect each bypass device according to the procedures of paragraph (a)(4) of this section.

* * * * *

(4) For each bypass device, except as provided for in § 60.5411a(a)(3)(ii), you must meet the requirements of paragraph (a)(4)(i) or (ii) of this section.

* * * * *

(b) *No detectable emissions test methods and procedures.* If you are required to conduct an inspection of a closed vent system or cover at your centrifugal compressor or reciprocating compressor affected facility as specified in paragraph (a)(1), (2), or (3) of this section, you must meet the requirements of paragraphs (b)(1) through (13) of this section.

* * * * *

(c) *Cover and closed vent system inspections for storage vessel affected facilities.* If you install a control device or route emissions to a process, you must comply with the inspection and recordkeeping requirements for each closed vent system and cover as specified in paragraphs (c)(1) and (2) of this section. You must also comply with the requirements of paragraphs (c)(3) through (7) of this section.

(1) *Closed vent system inspections.* For each closed vent system, you must conduct an inspection as specified in paragraphs (c)(1)(i) through (iii) or paragraph (c)(1)(iv) of this section.

(i) You must maintain records of the inspection results as specified in § 60.5420a(c)(6).

(ii) Conduct olfactory, visual, and auditory inspections at least once every calendar month for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in piping; loose connections; liquid leaks; or broken or missing caps or other closure devices.

(iii) Monthly inspections must be separated by at least 14 calendar days.

(iv) Conduct optical gas imaging inspections for any visible emissions at the same frequency as the frequency for the collection of fugitive emissions components located at the same type of site, as specified in § 60.5397a(g)(1).

(2) *Cover inspections.* For each cover, you must conduct inspections as specified in paragraphs (c)(2)(i) through (iii) or paragraph (c)(2)(iv) of this section.

* * * * *

(iv) Conduct optical gas imaging inspections for any visible emissions at the same frequency as the frequency for the collection of fugitive emissions components located at the same type of site, as specified in § 60.5397a(g)(1).

* * * * *

(d) *Closed vent system inspections for pneumatic pump affected facilities.* If you install a control device or route emissions to a process, you must comply with the inspection and recordkeeping requirements for each closed vent system as specified in paragraph (d)(1) of this section. You must also comply with the requirements of paragraphs (c)(3) through (7) of this section.

(1) For each closed vent system, you must conduct an inspection as specified in paragraphs (d)(1)(i) through (iii), paragraph (d)(1)(iv), or paragraph (d)(1)(v) of this section.

(i) You must maintain records of the inspection results as specified in § 60.5420a(c)(6).

(ii) Conduct olfactory, visual, and auditory inspections at least once every calendar month for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in piping; loose connections; liquid leaks; or broken or missing caps or other closure devices.

(iii) Monthly inspections must be separated by at least 14 calendar days.

(iv) Conduct optical gas imaging inspections for any visible emissions at the same frequency as the frequency for the collection of fugitive components located at the same type of site, as specified in § 60.5397a(g)(1).

(v) Conduct inspections as specified in paragraphs (a)(1) and (2) of this section.

(2) [Reserved]

■ 22. Section 60.5417a is amended by revising the introductory text and paragraph (a) to read as follows:

§ 60.5417a What are the continuous control device monitoring requirements for my centrifugal compressor and storage vessel affected facilities?

You must meet the applicable requirements of this section to demonstrate continuous compliance for each control device used to meet emission standards for your storage vessel affected facility or centrifugal compressor affected facility.

(a) For each control device used to comply with the emission reduction standard for centrifugal compressor affected facilities in § 60.5380a(a)(1), you must install and operate a continuous parameter monitoring system for each control device as specified in paragraphs (c) through (g) of this section, except as provided for in paragraph (b) of this section. If you install and operate a flare in accordance with § 60.5412a(a)(3), you are exempt from the requirements of paragraphs (e) and (f) of this section. If you install and operate an enclosed combustion device or control device which is not specifically listed in paragraph (d) of this section, you must demonstrate continuous compliance according to paragraphs (h)(1) through (4) of this section.

* * * * *

■ 23. Revise § 60.5420a to read as follows:

§ 60.5420a What are my notification, reporting, and recordkeeping requirements?

(a) *Notifications.* You must submit the notifications according to paragraphs (a)(1) and (2) of this section if you own or operate one or more of the affected facilities specified in § 60.5365a that was constructed, modified, or reconstructed during the reporting period.

(1) If you own or operate an affected facility that is the group of all equipment within a process unit at an onshore natural gas processing plant, or a sweetening unit, you must submit the notifications required in §§ 60.7(a)(1), (3), and (4) and 60.15(d). If you own or operate a well, centrifugal compressor, reciprocating compressor, pneumatic controller, pneumatic pump, storage vessel, collection of fugitive emissions components at a well site, or collection of fugitive emissions components at a compressor station, you are not required to submit the notifications required in §§ 60.7(a)(1), (3), and (4) and 60.15(d).

(2)(i) If you own or operate a well affected facility, you must submit a notification to the Administrator no later than 2 days prior to the commencement of each well completion operation listing the anticipated date of the well completion operation. The notification shall include contact information for the owner or operator; the United States Well Number; the latitude and longitude coordinates for each well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983; and the planned date of the beginning of flowback. You may submit the notification in writing or in electronic format.

(ii) If you are subject to state regulations that require advance notification of well completions and you have met those notification requirements, then you are considered to have met the advance notification requirements of paragraph (a)(2)(i) of this section.

(3) An owner or operator electing to comply with the provisions of § 60.5399a shall notify the Administrator of the alternative fugitive emissions standard selected within the annual report, as specified in paragraph (b)(7) of this section.

(b) *Reporting requirements.* You must submit annual reports containing the information specified in paragraphs (b)(1) through (8) and (12) of this section and performance test reports as specified in paragraph (b)(9) or (10) of this section, if applicable. You must submit annual reports following the procedure specified in paragraph (b)(11) of this section. The initial annual report is due no later than 90 days after the end of the initial compliance period as determined according to § 60.5410a. Subsequent annual reports are due no later than same date each year as the initial annual report. If you own or operate more than one affected facility, you may submit one report for multiple affected facilities provided the report contains all of the information required as specified in paragraphs (b)(1) through (8) and (12) of this section. Annual reports may coincide with title V reports as long as all the required elements of the annual report are included. You may arrange with the Administrator a common schedule on which reports required by this part may be submitted as long as the schedule does not extend the reporting period.

(1) The general information specified in paragraphs (b)(1)(i) through (iv) of this section is required for all reports.

(i) The company name, facility site name associated with the affected facility, U.S. Well ID or U.S. Well ID associated with the affected facility, if applicable, and address of the affected facility. If an address is not available for the site, include a description of the site location and provide the latitude and longitude coordinates of the site in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

(ii) An identification of each affected facility being included in the annual report.

(iii) Beginning and ending dates of the reporting period.

(iv) A certification by a certifying official of truth, accuracy, and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

(2) For each well affected facility that is subject to § 60.5375a(a) or (f), the records of each well completion operation conducted during the reporting period, including the information specified in paragraphs (b)(2)(i) through (xiv) of this section, if applicable. In lieu of submitting the records specified in paragraphs (b)(2)(i) through (xiv) of this section, the owner or operator may submit a list of each well completion with hydraulic fracturing completed during the reporting period, and the digital photograph required by paragraph (c)(1)(v) of this section for each well completion. For each well affected facility that routes flowback entirely through one or more production separators, only the records specified in paragraphs (b)(2)(i) through (iv) and (vi) of this section are required to be reported. For periods where salable gas is unable to be separated, the records specified in paragraphs (b)(2)(iv) and (viii) through (xii) of this section must also be reported, as applicable. For each well affected facility that is subject to § 60.5375a(g), the record specified in paragraph (b)(2)(xv) of this section is required to be reported.

(i) Well Completion ID.

(ii) Latitude and longitude of the well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using North American Datum of 1983.

(iii) U.S. Well ID.

(iv) The date and time of the onset of flowback following hydraulic fracturing or refracturing or identification that the well immediately starts production.

(v) The date and time of each attempt to direct flowback to a separator as required in § 60.5375a(a)(1)(ii).

(vi) The date and time that the well was shut in and the flowback equipment was permanently disconnected, or the startup of production.

(vii) The duration (in hours) of flowback.

(viii) The duration (in hours) of recovery and disposition of recovery (*i.e.,* routed to the gas flow line or collection system, re-injected into the well or another well, used as an onsite fuel source, or used for another useful purpose that a purchased fuel or raw material would serve).

(ix) The duration (in hours) of combustion.

(x) The duration (in hours) of venting.

(xi) The specific reasons for venting in lieu of capture or combustion.

(xii) For any deviations recorded as specified in paragraph (c)(1)(ii) of this section, the date and time the deviation began, the duration of the deviation, and a description of the deviation.

(xiii) For each well affected facility subject to § 60.5375a(f), a record of the well type (*i.e.,* wildcat well, delineation well, or low pressure well (as defined § 60.5430a)) and supporting inputs and calculations, if applicable.

(xiv) For each well affected facility for which you claim an exception under § 60.5375a(a)(3), the specific exception claimed and reasons why the well meets the claimed exception.

(xv) For each well affected facility with less than 300 scf of gas per stock tank barrel of oil produced, the supporting analysis that was performed in order the make that claim, including but not limited to, GOR values for established leases and data from wells in the same basin and field.

(3) For each centrifugal compressor affected facility, the information specified in paragraphs (b)(3)(i) through (v) of this section.

(i) An identification of each centrifugal compressor using a wet seal system constructed, modified, or reconstructed during the reporting period.

(ii) For each deviation that occurred during the reporting period and recorded as specified in paragraph (c)(2) of this section, the date and time the deviation began, the duration of the deviation, and a description of the deviation.

(iii) If required to comply with § 60.5380a(a)(2), the information in paragraphs (b)(3)(iii)(A) through (C) of this section.

(A) Dates of each inspection required under § 60.5416a(a) and (b);

(B) Each defect or leak identified during each inspection, date of repair or the date of anticipated repair if the repair is delayed; and

(C) Date and time of each bypass alarm or each instance the key is checked out if you are subject to the bypass requirements of § 60.5416a(a)(4).

(iv) If complying with § 60.5380a(a)(1) with a control device tested under § 60.5413a(d) which meets the criteria in § 60.5413a(d)(11) and (e), the information in paragraphs (b)(3)(iv)(A) through (D) of this section.

(A) Identification of the compressor with the control device.

(B) Make, model, and date of purchase of the control device.

(C) For each instance where the inlet gas flow rate exceeds the manufacturer's listed maximum gas flow rate, where there is no indication of the presence of a pilot flame, or where visible emissions exceeded 1 minute in any 15-minute period, include the date and time the deviation began, the duration of the deviation, and a description of the deviation.

(D) For each visible emissions test following return to operation from a maintenance or repair activity, the date of the visible emissions test, the length of the test, and the amount of time for which visible emissions were present.

(v) If complying with § 60.5380a(a)(1) with a control device not tested under § 60.5413a(d), identification of the compressor with the tested control device, the date the performance test was conducted, and pollutant(s) tested. Submit the performance test report following the procedures specified in paragraph (b)(9) of this section.

(4) For each reciprocating compressor affected facility, the information specified in paragraphs (b)(4)(i) through (iii) of this section.

(i) The cumulative number of hours of operation or the number of months since initial startup, since August 2, 2016, or since the previous reciprocating compressor rod packing replacement, whichever is latest. Alternatively, a statement that emissions from the rod packing are being routed to a process through a closed vent system under negative pressure.

(ii) If applicable, for each deviation that occurred during the reporting period and recorded as specified in paragraph (c)(3)(iii) of this section, the date and time the deviation began, duration of the deviation and a description of the deviation.

(iii) If required to comply with § 60.5385a(a)(3), the information in paragraphs (b)(4)(iii)(A) through (C) of this section.

(A) Dates of each inspection required under § 60.5416a(a) and (b);

(B) Each defect or leak identified during each inspection, and date of repair or date of anticipated repair if repair is delayed; and

(C) Date and time of each bypass alarm or each instance the key is checked out if you are subject to the bypass requirements of § 60.5416a(a)(4).

(5) For each pneumatic controller affected facility, the information specified in paragraphs (b)(5)(i) through (iii) of this section.

(i) An identification of each pneumatic controller constructed, modified, or reconstructed during the reporting period, including the month and year of installation, reconstruction or modification and identification information that allows traceability to the records required in paragraph (c)(4)(iii) or (iv) of this section.

(ii) If applicable, reason why the use of pneumatic controller affected facilities with a natural gas bleed rate greater than the applicable standard are required.

(iii) For each instance where the pneumatic controller was not operated in compliance with the requirements specified in § 60.5390a, a description of the deviation, the date and time the deviation began, and the duration of the deviation.

(6) For each storage vessel affected facility, the information in paragraphs (b)(6)(i) through (ix) of this section.

(i) An identification, including the location, of each storage vessel affected facility for which construction, modification, or reconstruction commenced during the reporting period. The location of the storage vessel shall be in latitude and longitude coordinates in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

(ii) Documentation of the VOC emission rate determination according to § 60.5365a(e)(1) for each storage vessel that became an affected facility during the reporting period or is returned to service during the reporting period.

(iii) For each deviation that occurred during the reporting period and recorded as specified in paragraph (c)(5) of this section, the date and time the deviation began, duration of the deviation and a description of the deviation.

(iv) A statement that you have met the requirements specified in § 60.5410a(h)(2) and (3).

(v) For each storage vessel constructed, modified, reconstructed, or returned to service during the reporting period complying with § 60.5395a(a)(2) with a control device tested under § 60.5413a(d) which meets the criteria in § 60.5413a(d)(11) and (e), the information in paragraphs (b)(6)(v)(A) through (D) of this section.

(A) Identification of the storage vessel with the control device.

(B) Make, model, and date of purchase of the control device.

(C) For each instance where the inlet gas flow rate exceeds the manufacturer's listed maximum gas flow rate, where there is no indication of the presence of a pilot flame, or where visible emissions exceeded 1 minute in any 15-minute period, include the date and time the deviation began, the duration of the deviation, and a description of the deviation.

(D) For each visible emissions test following return to operation from a maintenance or repair activity, the date of the visible emissions test, the length of the test, and the amount of time for which visible emissions were present.

(vi) If complying with § 60.5395a(a)(2) with a control device not tested under § 60.5413a(d), identification of the storage vessel with the tested control device, the date the performance test was conducted, and pollutant(s) tested. Submit the performance test report following the procedures specified in paragraph (b)(9) of this section.

(vii) If required to comply with § 60.5395a(b)(1), the information in paragraphs (b)(6)(vii)(A) through (C) of this section.

(A) Dates of each inspection required under § 60.5416a(c);

(B) Each defect or leak identified during each inspection, and date of repair or date of anticipated repair if repair is delayed; and

(C) Date and time of each bypass alarm or each instance the key is checked out if you are subject to the bypass requirements of § 60.5416a(c)(3).

(viii) You must identify each storage vessel affected facility that is removed from service during the reporting period as specified in § 60.5395a(c)(1)(ii), including the date the storage vessel affected facility was removed from service.

(ix) You must identify each storage vessel affected facility returned to service during the reporting period as specified in § 60.5395a(c)(3), including the date the storage vessel affected facility was returned to service.

(7) For the collection of fugitive emissions components at each well site and the collection of fugitive emissions components at each compressor station, report the information specified in paragraphs (b)(7)(i) through (iii) of this section, as applicable.

(i)(A) Designation of the type of site (*i.e.,* well site or compressor station) at which the collection of fugitive emissions components is located.

(B) For each collection of fugitive emissions components at a well site that became an affected facility during the reporting period, you must include the date of the startup of production or the date of the first day of production after modification. For each collection of fugitive emissions components at a compressor station that became an affected facility during the reporting period, you must include the date of startup or the date of modification.

(C) For each collection of fugitive emissions components at a well site that meets the conditions specified in either § 60.5397a(a)(1)(i) or (ii), you must specify the well site is a low production well site and submit the total production for the well site.

(D) For each collection of fugitive emissions components at a well site where during the reporting period you complete the removal of all major production and processing equipment such that the well site contains only one or more wellheads, you must include the date of the change to status as a wellhead only well site.

(E) For each collection of fugitive emissions components at a well site where you previously reported under paragraph (b)(7)(i)(C) of this section the removal of all major production and processing equipment and during the reporting period major production and processing equipment is added back to the well site, the date that the first piece of major production and processing equipment is added back to the well site.

(ii) For each fugitive emissions monitoring survey performed during the annual reporting period, the information specified in paragraphs (b)(7)(ii)(A) through (G) of this section.

(A) Date of the survey.

(B) Monitoring instrument used.

(C) Any deviations from the monitoring plan elements under § 60.5397a(c)(1), (2), and (7) and (c)(8)(i) or a statement that there were no deviations from these elements of the monitoring plan.

(D) Number and type of components for which fugitive emissions were detected.

(E) Number and type of fugitive emissions components that were not repaired as required in § 60.5397a(h).

(F) Number and type of fugitive emission components (including designation as difficult-to-monitor or unsafe-to-monitor, if applicable) on delay of repair and explanation for each delay of repair.

(G) Date of planned shutdown(s) that occurred during the reporting period if there are any components that have been placed on delay of repair.

(iii) For each collection of fugitive emissions components at a well site or collection of fugitive emissions components at a compressor station complying with an alternative fugitive emissions standard under § 60.5399a, in lieu of the information specified in paragraphs (b)(7)(i) and (ii) of this section, you must provide the information specified in paragraphs (b)(7)(iii)(A) through (C) of this section.

(A) The alternative standard with which you are complying.

(B) The site-specific reports specified by the specific alternative fugitive emissions standard, submitted in the format in which they were submitted to the state, local, or tribal authority. If the report is in hard copy, you must scan the document and submit it as an electronic attachment to the annual report required in paragraph (b) of this section.

(C) If the report specified by the specific alternative fugitive emissions standard is not site-specific, you must submit the information specified in paragraphs (b)(7)(i) and (ii) of this section for each individual site complying with the alternative standard.

(8) For each pneumatic pump affected facility, the information specified in paragraphs (b)(8)(i) through (iv) of this section.

(i) For each pneumatic pump that is constructed, modified or reconstructed during the reporting period, you must provide certification that the pneumatic pump meets one of the conditions described in paragraph (b)(8)(i)(A), (B), or (C) of this section.

(A) No control device or process is available on site.

(B) A control device or process is available on site and the owner or operator has determined in accordance with § 60.5393a(b)(5) that it is technically infeasible to capture and route the emissions to the control device or process.

(C) Emissions from the pneumatic pump are routed to a control device or process. If the control device is designed to achieve less than 95 percent emissions reduction, specify the percent emissions reductions the control device is designed to achieve.

(ii) For any pneumatic pump affected facility which has been previously reported as required under paragraph (b)(8)(i) of this section and for which a change in the reported condition has occurred during the reporting period, provide the identification of the pneumatic pump affected facility and the date it was previously reported and a certification that the pneumatic pump meets one of the conditions described in paragraph (b)(8)(ii)(A), (B), (C), or (D) of this section.

(A) A control device has been added to the location and the pneumatic pump now reports according to paragraph (b)(8)(i)(C) of this section.

(B) A control device has been added to the location and the pneumatic pump affected facility now reports according to paragraph (b)(8)(i)(B) of this section.

(C) A control device or process has been removed from the location or otherwise is no longer available and the pneumatic pump affected facility now report according to paragraph (b)(8)(i)(A) of this section.

(D) A control device or process has been removed from the location or is otherwise no longer available and the owner or operator has determined in accordance with § 60.5393a(b)(5) through an engineering evaluation that it is technically infeasible to capture and route the emissions to another control device or process.

(iii) For each deviation that occurred during the reporting period and recorded as specified in paragraph (c)(16)(ii) of this section, the date and time the deviation began, duration of the deviation, and a description of the deviation.

(iv) If required to comply with § 60.5393a(b), the information in paragraphs (b)(8)(iv)(A) through (C) of this section.

(A) Dates of each inspection required under § 60.5416a(d);

(B) Each defect or leak identified during each inspection, and date of repair or date of anticipated repair if repair is delayed; and

(C) Date and time of each bypass alarm or each instance the key is checked out if you are subject to the bypass requirements of § 60.5416a(c)(3).

(9) Within 60 days after the date of completing each performance test (see § 60.8) required by this subpart, except testing conducted by the manufacturer as specified in § 60.5413a(d), you must submit the results of the performance test following the procedure specified in either paragraph (b)(9)(i) or (ii) of this section.

(i) For data collected using test methods supported by the EPA's Electronic Reporting Tool (ERT) as listed on the EPA's ERT website (*https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert*) at the time of the test, you must submit the results of the performance test to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI), except as outlined in this paragraph (b)(9)(i). (CEDRI can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*).) The EPA will make all the information submitted through CEDRI available to the public without further notice to you. Do not use CEDRI to submit information you claim as confidential business information (CBI). Anything submitted using CEDRI cannot later be claimed CBI. Performance test data must be submitted in a file format generated through the use of the EPA's ERT or an alternate electronic file format consistent with the extensible markup language (XML) schema listed on the EPA's ERT website. Although we do not expect persons to assert a claim of CBI, if you wish to assert a CBI claim, you must submit a complete file generated through the use of the EPA's ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT website, including information claimed to be CBI, on a compact disc, flash drive, or other commonly used electronic storage media to the EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAQPS/CORE CBI Office, Attention: Group Leader, Measurement Policy Group, MD C404–02, 4930 Old Page Rd., Durham, NC 27703. The same ERT or alternate file with the CBI omitted must be submitted to the EPA via the EPA's CDX as described earlier in this paragraph (b)(9)(i). All CBI claims must be asserted at the time of submission. Furthermore, under CAA section 114(c), emissions data is not entitled to confidential treatment, and the EPA is required to make emissions data available to the public. Thus, emissions data will not be protected as CBI and will be made publicly available.

(ii) For data collected using test methods that are not supported by the EPA's ERT as listed on the EPA's ERT website at the time of the test, you must submit the results of the performance test to the Administrator at the appropriate address listed in § 60.4.

(10) For combustion control devices tested by the manufacturer in accordance with § 60.5413a(d), an electronic copy of the performance test results required by § 60.5413a(d) shall be submitted via email to *Oil_and_Gas_PT@EPA.GOV* unless the test results for that model of combustion control device are posted at the following website: *epa.gov/airquality/oilandgas/.*

(11) You must submit reports to the EPA via CEDRI, except as outlined in this paragraph (b)(11). (CEDRI can be accessed through the EPA's CDX (*https://cdx.epa.gov/*).) The EPA will make all the information submitted through CEDRI available to the public without further notice to you. Do not use CEDRI to submit information you claim as CBI. Anything submitted using CEDRI cannot later be claimed CBI. You must use the appropriate electronic report in CEDRI for this subpart or an alternate electronic file format consistent with the extensible markup language (XML) schema listed on the CEDRI website (*https://www.epa.gov/electronic-reporting-air-emissions/cedri/*). If the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, you must submit the report to the Administrator at the appropriate address listed in § 60.4. Once the form has been available in CEDRI for at least 90 calendar days, you must begin submitting all subsequent reports via CEDRI. The reports must be submitted by the

deadlines specified in this subpart, regardless of the method in which the reports are submitted. Although we do not expect persons to assert a claim of CBI, if you wish to assert a CBI claim, submit a complete report generated using the appropriate form in CEDRI or an alternate electronic file consistent with the XML schema listed on the EPA's CEDRI website, including information claimed to be CBI, on a compact disc, flash drive, or other commonly used electronic storage medium to the EPA. The electronic medium shall be clearly marked as CBI and mailed to U.S. EPA/OAQPS/CORE CBI Office, Attention: Group Leader, Fuels and Incineration Group, MD C404–02, 4930 Old Page Rd., Durham, NC 27703. The same file with the CBI omitted shall be submitted to the EPA via CEDRI. All CBI claims must be asserted at the time of submission. Furthermore, under CAA section 114(c), emissions data is not entitled to confidential treatment, and the EPA is required to make emissions data available to the public. Thus, emissions data will not be protected as CBI and will be made publicly available.

(12) You must submit the certification signed by the qualified professional engineer or in-house engineer according to § 60.5411a(d) for each closed vent system routing to a control device or process.

(13) If you are required to electronically submit a report through CEDRI in the EPA's CDX, you may assert a claim of EPA system outage for failure to timely comply with the reporting requirement. To assert a claim of EPA system outage, you must meet the requirements outlined in paragraphs (b)(13)(i) through (vii) of this section.

(i) You must have been or will be precluded from accessing CEDRI and submitting a required report within the time prescribed due to an outage of either the EPA's CEDRI or CDX systems.

(ii) The outage must have occurred within the period of time beginning 5 business days prior to the date that the submission is due.

(iii) The outage may be planned or unplanned.

(iv) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or caused a delay in reporting.

(v) You must provide to the Administrator a written description identifying:

(A) The date(s) and time(s) when CDX or CEDRI was accessed and the system was unavailable;

(B) A rationale for attributing the delay in reporting beyond the regulatory deadline to the EPA system outage;

(C) Measures taken or to be taken to minimize the delay in reporting; and

(D) The date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported.

(vi) The decision to accept the claim of EPA system outage and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

(vii) In any circumstance, the report must be submitted electronically as soon as possible after the outage is resolved.

(14) If you are required to electronically submit a report through CEDRI in the EPA's CDX, the owner or operator may assert a claim of force majeure for failure to timely comply with the reporting requirement. To assert a claim of force majeure, you must meet the requirements outlined in paragraphs (b)(14)(i) through (v) of this section.

(i) You may submit a claim if a force majeure event is about to occur, occurs, or has occurred or there are lingering effects from such an event within the period of time beginning 5 business days prior to the date the submission is due. For the purposes of this section, a force majeure event is defined as an event that will be or has been caused by circumstances beyond the control of the affected facility, its contractors, or any entity controlled by the affected facility that prevents you from complying with the requirement to submit a report electronically within the time period prescribed. Examples of such events are acts of nature (*e.g.,* hurricanes, earthquakes, or floods), acts of war or terrorism, or equipment failure or safety hazard beyond the control of the affected facility (*e.g.,* large scale power outage).

(ii) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or caused a delay in reporting.

(iii) You must provide to the Administrator:

(A) A written description of the force majeure event;

(B) A rationale for attributing the delay in reporting beyond the regulatory deadline to the force majeure event;

(C) Measures taken or to be taken to minimize the delay in reporting; and

(D) The date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported.

(iv) The decision to accept the claim of force majeure and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

(v) In any circumstance, the reporting must occur as soon as possible after the force majeure event occurs.

(c) *Recordkeeping requirements.* You must maintain the records identified as specified in § 60.7(f) and in paragraphs (c)(1) through (18) of this section. All records required by this subpart must be maintained either onsite or at the nearest local field office for at least 5 years. Any records required to be maintained by this subpart that are submitted electronically via the EPA's CDX may be maintained in electronic format.

(1) The records for each well affected facility as specified in paragraphs (c)(1)(i) through (vii) of this section, as applicable. For each well affected facility for which you make a claim that the well affected facility is not subject to the requirements for well completions pursuant to § 60.5375a(g), you must maintain the record in paragraph (c)(1)(vi) of this section, only. For each well affected facility that routes flowback entirely through one or more production separators that are designed to accommodate flowback, only records of the United States Well Number, the latitude and longitude of the well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using North American Datum of 1983, the Well Completion ID, and the date and time of startup of production are required. For periods where salable gas is unable to be separated, records of the date and time of onset of flowback, the duration and disposition of recovery, the duration of combustion and venting (if applicable), reasons for venting (if applicable), and deviations are required.

(i) Records identifying each well completion operation for each well affected facility.

(ii) Records of deviations in cases where well completion operations with hydraulic fracturing were not performed in compliance with the requirements specified in § 60.5375a, including the date and time the deviation began, the duration of the deviation, and a description of the deviation.

(iii) You must maintain the records specified in paragraphs (c)(1)(iii)(A) through (C) of this section.

(A) For each well affected facility required to comply with the requirements of § 60.5375a(a), you must record: The latitude and longitude of the well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using North American Datum of 1983; the United States Well Number; the date and time of the onset of flowback following hydraulic fracturing or refracturing; the date and time of each attempt to direct flowback to a separator as required in § 60.5375a(a)(1)(ii); the date and time of each occurrence of returning to the initial flowback stage under § 60.5375a(a)(1)(i); and the date and time that the well was shut in and the flowback equipment was permanently disconnected, or the startup of production; the duration of flowback; duration of recovery and disposition of recovery (*i.e.,* routed to the gas flow line or collection system, re-injected into the well or another well, used as an onsite fuel source, or used for another useful purpose that a purchased fuel or raw material would serve); duration of combustion; duration of venting; and specific reasons for venting in lieu of capture or combustion. The duration must be specified in hours. In addition, for wells where it is technically infeasible to route the recovered gas as specified in § 60.5375a(a)(1)(ii), you must record the reasons for the claim of technical infeasibility with respect to all four options provided in § 60.5375a(a)(1)(ii).

(B) For each well affected facility required to comply with the requirements of § 60.5375a(f), you must record: Latitude and longitude of the well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using North American Datum of 1983; the United States Well Number; the date and time of the onset of flowback following hydraulic fracturing or refracturing; the date and time that the well was shut in and the flowback equipment was permanently disconnected, or the startup of production; the duration of flowback; duration of recovery and disposition of recovery (*i.e.,* routed to the gas flow line or collection system, re-injected into the well or another well, used as an onsite fuel source, or used for another useful purpose that a purchased fuel or raw material would serve); duration of combustion; duration of venting; and specific reasons for venting in lieu of capture or combustion. The duration must be specified in hours.

(C) For each well affected facility for which you make a claim that it meets the criteria of § 60.5375a(a)(1)(iii)(A), you must maintain the following:

(*1*) The latitude and longitude of the well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using North American Datum of 1983; the United States Well Number; the date and time of the onset of flowback following hydraulic fracturing or refracturing; the date and time that the well was shut in and the flowback equipment was permanently disconnected, or the startup of production; the duration of flowback; duration of recovery and disposition of recovery (*i.e.,* routed to the gas flow line or collection system, re-injected into the well or another well, used as an onsite fuel source, or used for another useful purpose that a purchased fuel or raw material would serve); duration of combustion; duration of venting; and specific reasons for venting in lieu of capture or combustion. The duration must be specified in hours.

(*2*) If applicable, records that the conditions of § 60.5375a(a)(1)(iii)(A) are no longer met and that the well completion operation has been stopped and a separator installed. The records shall include the date and time the well completion operation was stopped and the date and time the separator was installed.

(*3*) A record of the claim signed by the certifying official that no liquids collection is at the well site. The claim must include a certification by a certifying official of truth, accuracy, and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

(iv) For each well affected facility for which you claim an exception under § 60.5375a(a)(3), you must record: The latitude and longitude of the well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using North American Datum of 1983; the United States Well Number; the specific exception claimed; the starting date and ending date for the period the well operated under the exception; and an explanation of why the well meets the claimed exception.

(v) For each well affected facility required to comply with both § 60.5375a(a)(1) and (3), if you are using a digital photograph in lieu of the records required in paragraphs (c)(1)(i) through (iv) of this section, you must retain the records of the digital photograph as specified in § 60.5410a(a)(4).

(vi) For each well affected facility for which you make a claim that the well affected facility is not subject to the well completion standards according to § 60.5375a(g), you must maintain:

(A) A record of the analysis that was performed in order the make that claim, including but not limited to, GOR values for established leases and data from wells in the same basin and field;

(B) the latitude and longitude of the well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using North American Datum of 1983; the United States Well Number;

(C) A record of the claim signed by the certifying official. The claim must include a certification by a certifying official of truth, accuracy, and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

(vii) For each well affected facility subject to § 60.5375a(f), a record of the well type (*i.e.,* wildcat well, delineation well, or low pressure well (as defined § 60.5430a)) and supporting inputs and calculations, if applicable.

(2) For each centrifugal compressor affected facility, you must maintain records of deviations in cases where the centrifugal compressor was not operated in compliance with the requirements specified in § 60.5380a, including a description of each deviation, the date and time each deviation began and the duration of each deviation. Except as specified in paragraph (c)(2)(viii) of this section, you must maintain the records in paragraphs (c)(2)(i) through (vii) of this section for each control device tested under § 60.5413a(d) which meets the criteria in § 60.5413a(d)(11) and (e) and used to comply with § 60.5380a(a)(1) for each centrifugal compressor.

(i) Make, model, and serial number of purchased device.

(ii) Date of purchase.

(iii) Copy of purchase order.

(iv) Location of the centrifugal compressor and control device in latitude and longitude coordinates in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

(v) Inlet gas flow rate.

(vi) Records of continuous compliance requirements in § 60.5413a(e) as specified in paragraphs (c)(2)(vi)(A) through (E) of this section.

(A) Records that the pilot flame is present at all times of operation.

(B) Records that the device was operated with no visible emissions except for periods not to exceed a total of 1 minute during any 15-minute period.

(C) Records of the maintenance and repair log.

(D) Records of the visible emissions test following return to operation from a maintenance or repair activity, including the date of the visible emissions test, the length of the test, and the amount of time for which visible emissions were present.

(E) Records of the manufacturer's written operating instructions, procedures, and maintenance schedule to ensure good air pollution control practices for minimizing emissions.

(vii) Records of deviations for instances where the inlet gas flow rate exceeds the manufacturer's listed maximum gas flow rate, where there is no indication of the presence of a pilot flame, or where visible emissions exceeded 1 minute in any 15-minute period, including a description of the deviation, the date and time the deviation began, and the duration of the deviation.

(viii) As an alternative to the requirements of paragraph (c)(2)(iv) of this section, you may maintain records of one or more digital photographs with the date the photograph was taken and the latitude and longitude of the centrifugal compressor and control device imbedded within or stored with the digital file. As an alternative to imbedded latitude and longitude within the digital photograph, the digital photograph may consist of a photograph of the centrifugal compressor and control device with a photograph of a separately operating GPS device within the same digital picture, provided the latitude and longitude output of the GPS unit can be clearly read in the digital photograph.

(3) For each reciprocating compressor affected facility, you must maintain the records in paragraphs (c)(3)(i) through (iii) of this section.

(i) Records of the cumulative number of hours of operation or number of months since initial startup, since August 2, 2016, or since the previous replacement of the reciprocating compressor rod packing, whichever is latest. Alternatively, a statement that emissions from the rod packing are being routed to a process through a closed vent system under negative pressure.

(ii) Records of the date and time of each reciprocating compressor rod packing replacement, or date of installation of a rod packing emissions collection system and closed vent system as specified in § 60.5385a(a)(3).

(iii) Records of deviations in cases where the reciprocating compressor was not operated in compliance with the requirements specified in § 60.5385a, including the date and time the deviation began, duration of the deviation, and a description of the deviation.

(4) For each pneumatic controller affected facility, you must maintain the records identified in paragraphs (c)(4)(i) through (v) of this section, as applicable.

(i) Records of the month and year of installation, reconstruction, or modification, location in latitude and longitude coordinates in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983, identification information that allows traceability to the records required in paragraph (c)(4)(iii) or (iv) of this section and manufacturer specifications for each pneumatic controller constructed, modified, or reconstructed.

(ii) Records of the demonstration that the use of pneumatic controller affected facilities with a natural gas bleed rate greater than the applicable standard are required and the reasons why.

(iii) If the pneumatic controller is not located at a natural gas processing plant, records of the manufacturer's specifications indicating that the controller is designed such that natural gas bleed rate is less than or equal to 6 standard cubic feet per hour.

(iv) If the pneumatic controller is located at a natural gas processing plant, records of the documentation that the natural gas bleed rate is zero.

(v) For each instance where the pneumatic controller was not operated in compliance with the requirements specified in § 60.5390a, a description of the deviation, the date and time the deviation began, and the duration of the deviation.

(5) For each storage vessel affected facility, you must maintain the records identified in paragraphs (c)(5)(i) through (vii) of this section.

(i) If required to reduce emissions by complying with § 60.5395a(a)(2), the records specified in §§ 60.5420a(c)(6) through (8) and 60.5416a(c)(6)(ii) and (c)(7)(ii). You must maintain the records in paragraph (c)(5)(vi) of this section for each control device tested under § 60.5413a(d) which meets the criteria in § 60.5413a(d)(11) and (e) and used to comply with § 60.5395a(a)(2) for each storage vessel.

(ii) Records of each VOC emissions determination for each storage vessel affected facility made under § 60.5365a(e) including identification of the model or calculation methodology used to calculate the VOC emission rate.

(iii) For each instance where the storage vessel was not operated in compliance with the requirements specified in §§ 60.5395a, 60.5411a, 60.5412a, and 60.5413a, as applicable, a description of the deviation, the date and time each deviation began, and the duration of the deviation.

(iv) For storage vessels that are skid-mounted or permanently attached to something that is mobile (such as trucks, railcars, barges or ships), records indicating the number of consecutive days that the vessel is located at a site in the crude oil and natural gas production source category. If a storage vessel is removed from a site and, within 30 days, is either returned to the site or replaced by another storage vessel at the site to serve the same or similar function, then the entire period since the original storage vessel was first located at the site, including the days when the storage vessel was removed, will be added to the count towards the number of consecutive days.

(v) You must maintain records of the identification and location in latitude and longitude coordinates in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983 of each storage vessel affected facility.

(vi) Except as specified in paragraph (c)(5)(vi)(G) of this section, you must maintain the records specified in paragraphs (c)(5)(vi)(A) through (H) of this section for each control device tested under § 60.5413a(d) which meets the criteria in § 60.5413a(d)(11) and (e) and used to comply with § 60.5395a(a)(2) for each storage vessel.

(A) Make, model, and serial number of purchased device.

(B) Date of purchase.

(C) Copy of purchase order.

(D) Location of the control device in latitude and longitude coordinates in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

(E) Inlet gas flow rate.

(F) Records of continuous compliance requirements in § 60.5413a(e) as specified in paragraphs (c)(5)(vi)(F)(*1*) through (*5*) of this section.

(*1*) Records that the pilot flame is present at all times of operation.

(*2*) Records that the device was operated with no visible emissions except for periods not to exceed a total of 1 minute during any 15-minute period.

(*3*) Records of the maintenance and repair log.

(*4*) Records of the visible emissions test following return to operation from a maintenance or repair activity, including the date of the visible emissions test, the length of the test, and the amount of time for which visible emissions were present.

(*5*) Records of the manufacturer's written operating instructions, procedures, and maintenance schedule to ensure good air pollution control practices for minimizing emissions.

(G) Records of deviations for instances where the inlet gas flow rate exceeds the manufacturer's listed maximum gas flow rate, where there is no indication of the presence of a pilot flame, or where visible emissions exceeded 1 minute in any 15-minute period, including a description of the deviation, the date and time the deviation began, and the duration of the deviation.

(H) As an alternative to the requirements of paragraph (c)(5)(vi)(D) of this section, you may maintain records of one or more digital photographs with the date the photograph was taken and the latitude and longitude of the storage vessel and control device imbedded within or stored with the digital file. As an alternative to imbedded latitude and longitude within the digital photograph, the digital photograph may consist of a photograph of the storage vessel and control device with a photograph of a separately operating GPS device within the same digital picture, provided the latitude and longitude output of the GPS unit can be clearly read in the digital photograph.

(vii) Records of the date that each storage vessel affected facility is removed from service and returned to service, as applicable.

(6) Records of each closed vent system inspection required under § 60.5416a(a)(1) and (2) and (b) for centrifugal compressors and reciprocating compressors, § 60.5416a(c)(1) for storage vessels, or § 60.5416a(e) for pneumatic pumps as required in paragraphs (c)(6)(i) through (iii) of this section.

(i) A record of each closed vent system inspection or no detectable emissions monitoring survey. You must include an identification number for each closed vent system (or other unique identification description selected by you) and the date of the inspection.

(ii) For each defect or leak detected during inspections required by § 60.5416a(a)(1) and (2), (b), (c)(1), or (d), you must record the location of the defect or leak, a description of the defect or the maximum concentration reading obtained if using Method 21 of appendix A–7 of this part, the date of detection, and the date the repair to correct the defect or leak is completed.

(iii) If repair of the defect is delayed as described in § 60.5416a(b)(10), you must record the reason for the delay and the date you expect to complete the repair.

(7) A record of each cover inspection required under § 60.5416a(a)(3) for centrifugal or reciprocating compressors or § 60.5416a(c)(2) for storage vessels as required in paragraphs (c)(7)(i) through (iii) of this section.

(i) A record of each cover inspection. You must include an identification number for each cover (or other unique identification description selected by you) and the date of the inspection.

(ii) For each defect detected during inspections required by § 60.5416a(a)(3) or (c)(2), you must record the location of the defect, a description of the defect, the date of detection, the corrective action taken the repair the defect, and the date the repair to correct the defect is completed.

(iii) If repair of the defect is delayed as described in § 60.5416a(b)(10) or (c)(5), you must record the reason for the delay and the date you expect to complete the repair.

(8) If you are subject to the bypass requirements of § 60.5416a(a)(4) for centrifugal compressors or reciprocating compressors, or § 60.5416a(c)(3) for storage vessels or pneumatic pumps, you must prepare and maintain a record of each inspection or a record of each time the key is checked out or a record of each time the alarm is sounded.

(9) [Reserved]

(10) For each centrifugal compressor or pneumatic pump affected facility, records of the schedule for carbon replacement (as determined by the design analysis requirements of § 60.5413a(c)(2) or (3)) and records of each carbon replacement as specified in § 60.5412a(c)(1).

(11) For each centrifugal compressor affected facility subject to the control device requirements of § 60.5412a(a), (b), and (c), records of minimum and maximum operating parameter values, continuous parameter monitoring system data, calculated averages of continuous parameter monitoring system data, results of all compliance calculations, and results of all inspections.

(12) For each carbon adsorber installed on storage vessel affected facilities, records of the schedule for carbon replacement (as determined by the design analysis requirements of § 60.5412a(d)(2)) and records of each carbon replacement as specified in § 60.5412a(c)(1).

(13) For each storage vessel affected facility subject to the control device requirements of § 60.5412a(c) and (d), you must maintain records of the inspections, including any corrective actions taken, the manufacturers' operating instructions, procedures and maintenance schedule as specified in § 60.5417a(h)(3). You must maintain records of EPA Method 22 of appendix A–7 of this part, section 11 results, which include: Company, location, company representative (name of the person performing the observation), sky conditions, process unit (type of control device), clock start time, observation period duration (in minutes and seconds), accumulated emission time (in minutes and seconds), and clock end time. You may create your own form including the above information or use Figure 22–1 in EPA Method 22 of appendix A–7 of this part. Manufacturer's operating instructions, procedures and maintenance schedule must be available for inspection.

(14) A log of records as specified in § 60.5412a(d)(1)(iii), for all inspection, repair, and maintenance activities for each control device failing the visible emissions test.

(15) For each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a compressor station, maintain the records identified in paragraphs (c)(15)(i) through (viii) of this section.

(i) The date of the startup of production or the date of the first day of production after modification for each collection of fugitive emissions components at a well site and the date of startup or the date of modification for each collection of fugitive emissions components at a compressor station.

(ii) For each collection of fugitive emissions components at a well site complying with § 60.5397a(a)(2), you must maintain records of the daily production and calculations demonstrating that the rolling 12-month average is at or below 15 boe per day no later than 12 months before complying with § 60.5397a(a)(2).

(iii) For each collection of fugitive emissions components at a well site complying with § 60.5397a(a)(3)(i), you must keep records of daily production and calculations for the first 30 days after completion of any action listed in § 60.5397a(a)(2)(i) through (v) demonstrating that total production from the well site is at or below 15 boe per day, or maintain records demonstrating the rolling 12-month average total production for the well site is at or below 15 boe per day.

(iv) For each collection of fugitive emissions components at a well site complying with § 60.5397a(a)(3)(ii), you must keep the records specified in paragraphs (c)(15)(i), (vi), and (vii) of this section.

(v) For each collection of fugitive emissions components at a well site where you complete the removal of all major production and processing equipment such that the well site contains only one or more wellheads, record the date the well site completes the removal of all major production and processing equipment from the well site, and, if the well site is still producing, record the well ID or separate tank battery ID receiving the production from the well site. If major production and processing equipment is subsequently added back to the well site, record the date that the first piece of major production and processing equipment is added back to the well site.

(vi) The fugitive emissions monitoring plan as required in § 60.5397a(b), (c), and (d).

(vii) The records of each monitoring survey as specified in paragraphs (c)(15)(vii)(A) through (I) of this section.

(A) Date of the survey.

(B) Beginning and end time of the survey.

(C) Name of operator(s), training, and experience of the operator(s) performing the survey.

(D) Monitoring instrument used.

(E) Fugitive emissions component identification when Method 21 of appendix A–7 of this part is used to perform the monitoring survey.

(F) Ambient temperature, sky conditions, and maximum wind speed at the time of the survey. For compressor stations, operating mode of each compressor (*i.e.,* operating, standby pressurized, and not operating-depressurized modes) at the station at the time of the survey.

(G) Any deviations from the monitoring plan or a statement that there were no deviations from the monitoring plan.

(H) Records of calibrations for the instrument used during the monitoring survey.

(I) Documentation of each fugitive emission detected during the monitoring survey, including the information specified in paragraphs (c)(15)(vii)(I)(*1*) through (*8*) of this section.

(*1*) Location of each fugitive emission identified.

(*2*) Type of fugitive emissions component, including designation as difficult-to-monitor or unsafe-to-monitor, if applicable.

(*3*) If Method 21 of appendix A–7 of this part is used for detection, record the component ID and instrument reading.

(*4*) For each repair that cannot be made during the monitoring survey when the fugitive emissions are initially found, a digital photograph or video must be taken of that component or the component must be tagged for identification purposes. The digital photograph must include the date that the photograph was taken and must clearly identify the component by location within the site (*e.g.,* the latitude and longitude of the component or by other descriptive landmarks visible in the picture). The digital photograph or identification (*e.g.,* tag) may be removed after the repair is completed, including verification of repair with the resurvey.

(*5*) The date of first attempt at repair of the fugitive emissions component(s).

(*6*) The date of successful repair of the fugitive emissions component, including the resurvey to verify repair and instrument used for the resurvey.

(*7*) Identification of each fugitive emission component placed on delay of repair and explanation for each delay of repair

(*8*) Date of planned shutdowns that occur while there are any components that have been placed on delay of repair.

(viii) For each collection of fugitive emissions components at a well site or collection of fugitive emissions components at a compressor station complying with an alternative means of emissions limitation under § 60.5399a, you must maintain the records specified by the specific alternative fugitive emissions standard for a period of at least 5 years.

(16) For each pneumatic pump affected facility, you must maintain the records identified in paragraphs (c)(16)(i) through (v) of this section.

(i) Records of the date, location, and manufacturer specifications for each pneumatic pump constructed, modified, or reconstructed.

(ii) Records of deviations in cases where the pneumatic pump was not operated in compliance with the requirements specified in § 60.5393a, including the date and time the deviation began, duration of the deviation, and a description of the deviation.

(iii) Records on the control device used for control of emissions from a pneumatic pump including the installation date, and manufacturer's specifications. If the control device is designed to achieve less than 95-percent emission reduction, maintain records of the design evaluation or manufacturer's specifications which indicate the percentage reduction the control device is designed to achieve.

(iv) Records substantiating a claim according to § 60.5393a(b)(5) that it is technically infeasible to capture and route emissions from a pneumatic pump to a control device or process; including the certification according to § 60.5393a(b)(5)(ii) and the records of the engineering assessment of technical infeasibility performed according to § 60.5393a(b)(5)(iii).

(v) You must retain copies of all certifications, engineering assessments, and related records for a period of five years and make them available if directed by the implementing agency.

(17) For each closed vent system routing to a control device or process, the records of the assessment conducted according to § 60.5411a(d):

(i) A copy of the assessment conducted according to § 60.5411a(d)(1);

(ii) A copy of the certification according to § 60.5411a(d)(1)(i); and

(iii) The owner or operator shall retain copies of all certifications, assessments, and any related records for a period of 5 years, and make them available if directed by the delegated authority.

(18) A copy of each performance test submitted under paragraph (b)(9) of this section.

■ 24. Section 60.5422a is amended by revising paragraphs (a), (b), and (c) introductory text to read as follows:

§ 60.5422a What are my additional reporting requirements for my affected facility subject to VOC requirements for onshore natural gas processing plants?

(a) You must comply with the requirements of paragraphs (b) and (c) of this section in addition to the requirements of § 60.487a(a), (b)(1) through (3) and (5), and (c)(2)(i) through (iv) and (vii) through (viii). You must submit semiannual reports to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI). (CEDRI can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*).) Use the appropriate electronic report in CEDRI for this subpart or an alternate electronic file format consistent with the extensible markup language (XML) schema listed on the CEDRI website (*https://www3.epa.gov/ttn/chief/cedri/*). If the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, submit the report to the Administrator at the appropriate address listed in § 60.4. Once the form has been available in CEDRI for at least 90 days, you must begin submitting all subsequent reports via CEDRI. The report must be submitted by the deadline specified in this subpart, regardless of the method in which the report is submitted.

(b) An owner or operator must include the following information in the initial semiannual report in addition to the information required in § 60.487a(b)(1) through (3) and (5): Number of pressure relief devices subject to the requirements of § 60.5401a(b) except for those pressure relief devices designated for no detectable emissions under the provisions of § 60.482–4a(a) and those pressure relief devices complying with § 60.482–4a(c).

(c) An owner or operator must include the information specified in paragraphs (c)(1) and (2) of this section in all semiannual reports in addition to the information required in § 60.487a(c)(2)(i) through (iv) and (vii) through (viii):

* * * * *

■ 25. Section 60.5423a is amended by revising the section heading and paragraph (b) introductory text and adding paragraph (b)(3) to read as follows:

§ 60.5423a What additional recordkeeping and reporting requirements apply to my sweetening unit affected facilities?

* * * * *

(b) You must submit a report of excess emissions to the Administrator in your annual report if you had excess emissions during the reporting period. The procedures for submitting annual reports are located in § 60.5420a(b). For the purpose of these reports, excess emissions are defined as specified in paragraphs (b)(1) and (2) of this section. The report must contain the information specified in paragraph (b)(3) of this section.

* * * * *

(3) For each period of excess emissions during the reporting period, include the following information in your report:

(i) The date and time of commencement and completion of each period of excess emissions;

(ii) The required minimum efficiency (Z) and the actual average sulfur emissions reduction (R) for periods defined in paragraph (b)(1) of this section; and

(iii) The appropriate operating temperature and the actual average temperature of the gases leaving the combustion zone for periods defined in paragraph (b)(2) of this section.

* * * * *

■ 26. Section 60.5430a is amended by:

■ a. Revising the definitions for ''Capital expenditure'' and ''Certifying official'';

■ b. Adding in alphabetical order the definitions for ''Coil tubing cleanout,'' ''Custody meter,'' ''Custody meter assembly,'' and ''First attempt at repair'';

■ c. Revising the definitions for ''Flowback'' and ''Fugitive emissions component'';

■ d. Removing the definitions for ''Gas processing plant process unit'' and ''Greenfield site'';

■ e. Revising the definition of ''Low pressure well'';

■ f. Adding in alphabetical order the definition for ''Major production and processing equipment'';

■ g. Revising the definition for ''Maximum average daily throughput'';

■ h. Adding in alphabetical order the definitions for ''Plug drill-out,'' ''Repaired,'' and ''Screenout'';

■ i. Revising the definition for ''Startup of production'';

■ j. Adding in alphabetical order the definitions for ''UIC Class I oilfield disposal well'' and ''UIC Class II oilfield disposal well'';

■ k. Revising the definition for ''Well site''; and

■ l. Adding in alphabetical order the definition for ''Wellhead only well site''.

The revisions and additions read as follows:

§ 60.5430a What definitions apply to this subpart?

* * * * *

Capital expenditure means, in addition to the definition in 40 CFR 60.2, an expenditure for a physical or operational change to an existing facility that:

(1) Exceeds P, the product of the facility's replacement cost, R, and an adjusted annual asset guideline repair allowance, A, as reflected by the following equation: $P = R \times A$, where:

(i) The adjusted annual asset guideline repair allowance, A, is the product of the percent of the replacement cost, Y, and the applicable basic annual asset guideline repair allowance, B, divided by 100 as reflected by the following equation: $A = Y \times (B \div 100)$;

(ii) The percent Y is determined from the following equation: Y = (CPI of date of construction/most recently available CPI of date of project), where the ''CPI–U, U.S. city average, all items'' must be used for each CPI value; and

(iii) The applicable basic annual asset guideline repair allowance, B, is 4.5.

* * * * *

Certifying official means one of the following:

(1) For a corporation: A president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities with an affected facility subject to this subpart and either:

(i) The facilities employ more than 250 persons or have gross annual sales or expenditures exceeding $25 million (in second quarter 1980 dollars); or

(ii) The Administrator is notified of such delegation of authority prior to the exercise of that authority. The Administrator reserves the right to evaluate such delegation;

(2) For a partnership (including but not limited to general partnerships, limited partnerships, and limited liability partnerships) or sole proprietorship: A general partner or the proprietor, respectively. If a general partner is a corporation, the provisions of paragraph (1) of this definition apply;

(3) For a municipality, State, Federal, or other public agency: Either a principal executive officer or ranking elected official. For the purposes of this part, a principal executive officer of a Federal agency includes the chief executive officer having responsibility for the overall operations of a principal geographic unit of the agency (*e.g.,* a Regional Administrator of EPA); or

(4) For affected facilities:

(i) The designated representative in so far as actions, standards, requirements, or prohibitions under title IV of the CAA or the regulations promulgated thereunder are concerned; or

(ii) The designated representative for any other purposes under this part.

Coil tubing cleanout means the process where an operator runs a string of coil tubing to the packed proppant within a well and jets the well to dislodge the proppant and provide sufficient lift energy to flow it to the surface. Coil tubing cleanout includes mechanical methods to remove solids and/or debris from a wellbore.

* * * * *

Custody meter means the meter where natural gas or hydrocarbon liquids are measured for sales, transfers, and/or royalty determination.

Custody meter assembly means an assembly of fugitive emissions components, including the custody meter, valves, flanges, and connectors necessary for the proper operation of the custody meter.

* * * * *

First attempt at repair means, for the purposes of fugitive emissions components, an action taken for the purpose of stopping or reducing fugitive emissions to the atmosphere. First attempts at repair include, but are not limited to, the following practices where practicable and appropriate: Tightening bonnet bolts; replacing bonnet bolts; tightening packing gland nuts; or injecting lubricant into lubricated packing.

* * * * *

Flowback means the process of allowing fluids and entrained solids to flow from a well following a treatment, either in preparation for a subsequent phase of treatment or in preparation for cleanup and returning the well to production. The term flowback also means the fluids and entrained solids that emerge from a well during the flowback process. The flowback period begins when material introduced into the well during the treatment returns to the surface following hydraulic fracturing or refracturing. The flowback period ends when either the well is shut in and permanently disconnected from the flowback equipment or at the startup of production. The flowback period includes the initial flowback stage and the separation flowback stage. Screenouts, coil tubing cleanouts, and plug drill-outs are not considered part of the flowback process.

Fugitive emissions component means any component that has the potential to emit fugitive emissions of VOC at a well site or compressor station, including valves, connectors, pressure relief devices, open-ended lines, flanges, covers and closed vent systems not subject to § 60.5411 or § 60.5411a, thief hatches or other openings on a controlled storage vessel not subject to § 60.5395 or § 60.5395a, compressors, instruments, and meters. Devices that vent as part of normal operations, such as natural gas-driven pneumatic controllers or natural gas-driven pumps, are not fugitive emissions components, insofar as the natural gas discharged from the device's vent is not considered a fugitive emission. Emissions originating from other than the device's vent, such as the thief hatch on a controlled storage vessel, would be considered fugitive emissions.

* * * * *

Low pressure well means a well that satisfies at least one of the following conditions:

(1) The static pressure at the wellhead following fracturing but prior to the onset of flowback is less than the flow line pressure;

(2) The pressure of flowback fluid immediately before it enters the flow line, as determined under § 60.5432a, is less than the flow line pressure; or

(3) Flowback of the fracture fluids will not occur without the use of artificial lift equipment.

Major production and processing equipment means reciprocating or centrifugal compressors, glycol dehydrators, heater/treaters, separators, and storage vessels collecting crude oil, condensate, intermediate hydrocarbon liquids, or produced water, for the purpose of determining whether a well site is a wellhead only well site.

Maximum average daily throughput means the following:

(1) For storage vessels that commenced construction, reconstruction, or modification after September 18, 2015, and on and before November 16, 2020, *maximum average daily throughput* means the earliest calculation of daily average throughput during the 30-day PTE evaluation period employing generally accepted methods.

(2) For storage vessels that commenced construction, reconstruction, or modification after November 16, 2020, *maximum average daily throughput* means the earliest calculation of daily average throughput, determined as described in paragraph (3) or (4) of this definition, to an individual storage vessel over the days that production is routed to that storage vessel during the 30-day PTE evaluation period employing generally accepted methods specified in § 60.5365a(e)(1).

(3) If throughput to the individual storage vessel is measured on a daily basis (*e.g.,* via level gauge automation or daily manual gauging), the maximum average daily throughput is the average of all daily throughputs for days on which throughput was routed to that storage vessel during the 30-day evaluation period; or

(4) If throughput to the individual storage vessel is not measured on a daily basis (*e.g.,* via manual gauging at the start and end of loadouts), the maximum average daily throughput is the highest, of the average daily throughputs, determined for any production period to that storage vessel during the 30-day evaluation period, as determined by averaging total throughput to that storage vessel over each production period. A production period begins when production begins to be routed to a storage vessel and ends either when throughput is routed away from that storage vessel or when a loadout occurs from that storage vessel, whichever happens first. Regardless of the determination methodology, operators must not include days during which throughput is not routed to an individual storage vessel when calculating maximum average daily throughput for that storage vessel.

* * * * *

Plug drill-out means the removal of a plug (or plugs) that was used to isolate different sections of the well.

* * * * *

Repaired means, for the purposes of fugitive emissions components, that fugitive emissions components are adjusted, replaced, or otherwise altered, in order to eliminate fugitive emissions as defined in § 60.5397a and resurveyed as specified in § 60.5397a(h)(4) and it is verified that emissions from the fugitive emissions components are below the applicable fugitive emissions definition.

* * * * *

Screenout means an attempt to clear proppant from the wellbore to dislodge the proppant out of the well.

* * * * *

Startup of production means the beginning of initial flow following the end of flowback when there is continuous recovery of salable quality gas and separation and recovery of any crude oil, condensate, or produced water, except as otherwise provided in this definition. For the purposes of the fugitive monitoring requirements of § 60.5397a, *startup of production* means the beginning of the continuous recovery of salable quality gas and separation and recovery of any crude oil, condensate, or produced water.

* * * * *

UIC Class I oilfield disposal well means a well with a UIC Class I permit that meets the definition in 40 CFR 144.6(a)(2) and receives eligible fluids from oil and natural gas exploration and production operations.

UIC Class II oilfield disposal well means a well with a UIC Class II permit where wastewater resulting from oil and natural gas production operations is injected into underground porous rock formations not productive of oil or gas, and sealed above and below by unbroken, impermeable strata.

* * * * *

Well site means one or more surface sites that are constructed for the drilling and subsequent operation of any oil well, natural gas well, or injection well. For purposes of the fugitive emissions standards at § 60.5397a, well site also means a separate tank battery surface site collecting crude oil, condensate, intermediate hydrocarbon liquids, or produced water from wells not located at the well site (*e.g.,* centralized tank batteries). Also, for the purposes of the fugitive emissions standards at § 60.5397a, a well site does not include:

(1) UIC Class II oilfield disposal wells and disposal facilities;

(2) UIC Class I oilfield disposal wells; and

(3) The flange immediately upstream of the custody meter assembly and equipment, including fugitive emissions components, located downstream of this flange.

* * * * *

Wellhead only well site means, for the purposes of the fugitive emissions standards at § 60.5397a, a well site that contains one or more wellheads and no major production and processing equipment.

* * * * *

■ 27. Table 3 to subpart OOOOa of part 60 is amended by revising the entries for §§ 60.8 and 60.15 to read as follows:

TABLE 3 TO SUBPART OOOOa OF PART 60—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART OOOOa

General provisions citation	Subject of citation	Applies to subpart?	Explanation
*	*	*	* * * *
§ 60.8	Performance tests	Yes	Except that the format of performance test reports is described in § 60.5420a(b). Performance testing is required for control devices used on storage vessels, centrifugal compressors, and pneumatic pumps, except that performance testing is not required for a control device used solely on pneumatic pump(s).
*	*	*	* * * *
§ 60.15	Reconstruction	Yes	Except that § 60.15(d) does not apply to wells, pneumatic controllers, pneumatic pumps, centrifugal compressors, reciprocating compressors, storage vessels, or the collection of fugitive emissions components at a well site or the collection of fugitive emissions components at a compressor station.
*	*	*	* * * *

[FR Doc. 2020–18115 Filed 9–10–20; 8:45 am]

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ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 51, 60, 61, and 63

[EPA–HQ–OAR–2018–0815; FRL–10012–11–OAR]

RIN 2060–AU39

Test Methods and Performance Specifications for Air Emission Sources

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This action corrects and updates regulations for source testing of emissions. These revisions include corrections to inaccurate testing provisions, updates to outdated procedures, and approved alternative procedures that will provide flexibility to testers. These revisions will improve the quality of data and will not impose any new substantive requirements on source owners or operators.

DATES: The final rule is effective on December 7, 2020. The incorporation by reference of certain materials listed in the rule is approved by the Director of the Federal Register as of December 7, 2020]. The incorporation by reference of certain other materials listed in the rule was approved by the Director of the Federal Register as of July 6, 2006.

ADDRESSES: The EPA has established a docket for this action under Docket ID No. EPA–HQ–OAR–2018–0815. All documents in the docket are listed on the *http://www.regulations.gov* website. Although listed in the index, some information is not publicly available, *e.g.,* confidential business information or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the internet and will be publicly available only in hard copy. Publicly available docket materials are available electronically through *http://www.regulations.gov*.

FOR FURTHER INFORMATION CONTACT: Mrs. Lula H. Melton, Office of Air Quality Planning and Standards, Air Quality Assessment Division (E143–02), Environmental Protection Agency, Research Triangle Park, NC 27711; telephone number: (919) 541–2910; fax number: (919) 541–0516; email address: *melton.lula@epa.gov*.

SUPPLEMENTARY INFORMATION:

The supplementary information in this preamble is organized as follows:

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T. Method 26A of Appendix A–8 of Part 60
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V. Performance Specification 5 of Appendix B of Part 60
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K. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations
L. Congressional Review Act (CRA)

I. General Information

A. Does this action apply to me?

The revisions promulgated in this final rule apply to industries that are subject to the current provisions of 40 Code of Federal Regulations (CFR) parts 51, 60, 61, and 63. We did not list all of the specific affected industries or their North American Industry Classification System (NAICS) codes herein since there are many affected sources in numerous NAICS categories. 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 63.13.

B. What action is the Agency taking?

We are promulgating corrections and updates to regulations for source testing of emissions. More specifically, we are correcting typographical and technical errors, updating testing procedures, and adding alternative equipment and methods the Agency has deemed acceptable to use.

C. Judicial Review

Under section 307(b)(1) of the Clean Air Act (CAA), judicial review of this final rule is available by filing a petition for review in the United States Court of Appeals for the District of Columbia Circuit by December 7, 2020. Under section 307(d)(7)(B) of the CAA, only an objection to this final rule that was raised with reasonable specificity during the period for public comment can be raised during judicial review. Moreover, under section 307(b)(2) of the CAA, the requirements that are the requirement (*e.g.,* a requirement to conduct a compliance or performance test), then you must receive approval from the authority that established the regulatory requirement before you conduct the test.

* * * * *

6.2.1 * * *

(d) Petri dishes. For filter samples; glass, polystyrene, or polyethylene, unless otherwise specified by the Administrator.

* * * * *

8.6.6 *Sampling Head.* You must preheat the combined sampling head to the stack temperature of the gas stream at the test location (±28 °C, ±50 °F). This will heat the sampling head and prevent moisture from condensing from the sample gas stream.

* * * * *

17.0 * * *

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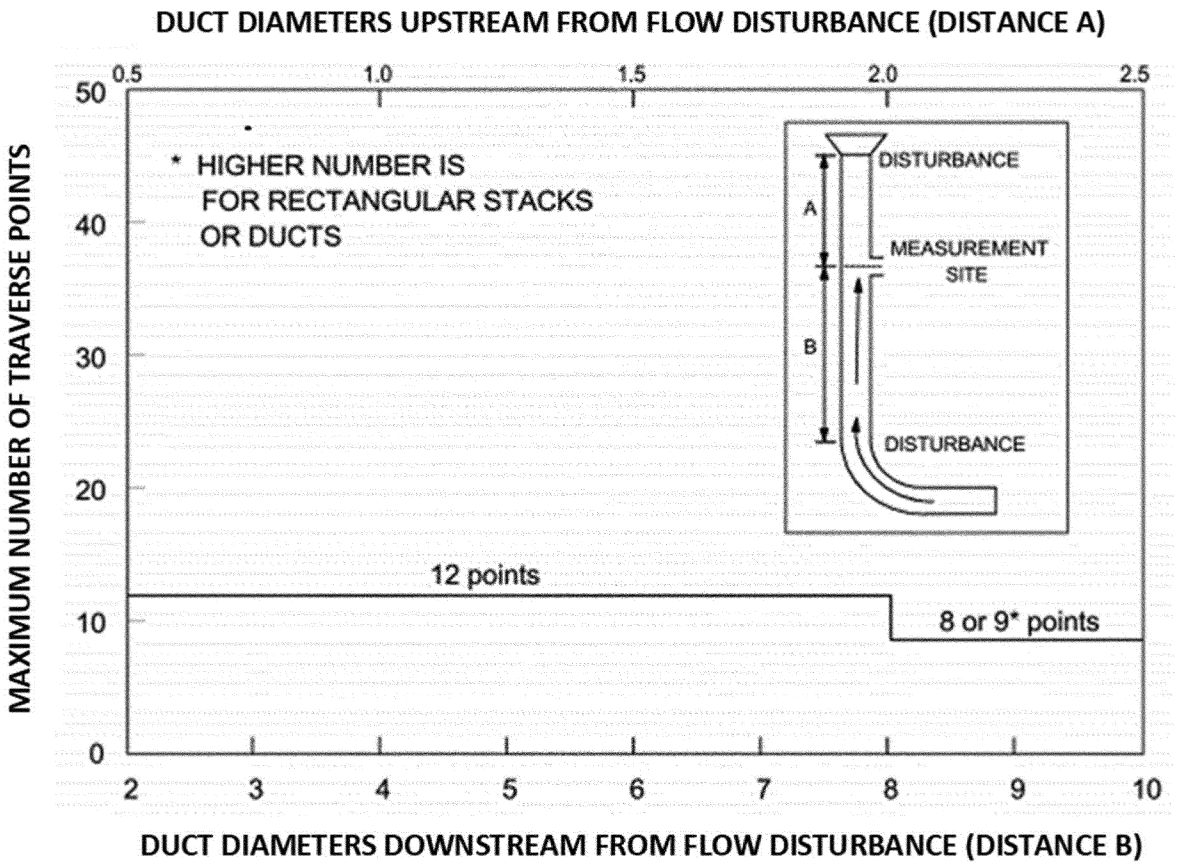

Figure 7. Maximum Number of Required Traverse Points

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PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

■ 3. The authority citation for part 60 continues to read as follows:

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

■ 4. Amend § 60.17 by:

■ a. Removing the text ''appendix A–8 to part 60: Method 24,'' and add in its place, ''appendix A–7 to part 60: Method 24,'' everywhere it appears;

■ b. Revising the last sentence in paragraph (a);

■ c. Redesignating paragraph (e)(2) as (e)(3) and adding a new paragraph (e)(2);

■ d. Redesignating paragraphs (h)(192) through (209) as (h)(195) through (212), (h)(174) through (191) as (h)(176) through (193), and (h)(95) through (173) as (h)(96) through (174), respectively;

■ e. Adding new paragraphs (h)(95), (175), and (194);

■ f. Adding paragraphs (j)(3) and (4);

■ g. Revising paragraph (k) introductory text;

■ h. Redesignating paragraphs (k)(2) and (3) as paragraphs (k)(5) and (6) and redesignating paragraph (k)(1) as paragraph (k)(3), respectively;

■ i. Adding new paragraphs (k)(1), (2), and (4);

■ j. Revising newly redesignated paragraph (k)(5); and

■ k. Adding paragraph (l)(2).

The revisions and additions read as follows:

§ 60.17 Incorporations by reference.

(a) * * * For information on the availability of this material at NARA, email *fedreg.legal@nara.gov,* or go to *www.archives.gov/federal-register/cfr/ibr-locations.html.*

* * * * *

(e) * * *

(2) API Manual of Petroleum Measurement Standards, Chapter 14—Natural Gas Fluids Measurement, Section 1—Collecting and Handling of Natural Gas Samples for Custody Transfer, 7th Edition, May 2016, IBR approved for § 60.4415(a).

* * * * *

(h) * * *

(95) ASTM D2369–10 (Reapproved 2015)e1, Standard Test Method for Volatile Content of Coatings, (Approved June 1, 2015); IBR approved for appendix A–7 to part 60: Method 24, Section 6.2.

* * * * *

(175) ASTM D5623–19, Standard Test Method for Sulfur Compounds in Light Petroleum Liquids by Gas Chromatography and Sulfur Selective Detection, (Approved July 1, 2019); IBR approved for § 60.4415(a).

* * * * *

(194) ASTM D7039–15a, Standard Test Method for Sulfur in Gasoline, Diesel Fuel, Jet Fuel, Kerosine, Boideisel, Biodiesel Blends, and Gasoline-Ethanol Blends by Monochromatic Wavelength Dispersive X-ray Fluorescence Spectrometry, (Approved July 1, 2015); IBR approved for § 60.4415(a).

* * * * *

(j) * * *

(3) SW–846–6010D, Inductively Coupled Plasma-Optical Emission Spectrometry, Revision 5, July 2018, in EPA Publication No. SW–846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Third Edition, IBR approved for appendix A–5 to part 60: Method 12.

(4) SW–846–6020B, Inductively Coupled Plasma-Mass Spectrometry, Revision 2, July 2014, in EPA Publication No. SW–846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Third Edition, IBR approved for appendix A–5 to part 60: Method 12.

(k) GPA Midstream Association (formerly known as Gas Processors Association), Sixty Sixty American Plaza, Suite 700, Tulsa, OK 74135.

Note 1 to paragraph (k): Material in this paragraph that is no longer available from GPA may be available through the reseller HIS Markit, 15 Inverness Way East, P.O. Box 1154, Englewood, CO 80150–1154, *https://global.ihs.com/.* For material that is out-of-print, contact EPA's Air and Radiation Docket and Information Center, Room 3334, 1301 Constitution Ave. NW, Washington, DC 20460 or *a-and-rdocket@epa.gov.*

(1) GPA Midstream Standard 2140–17 (GPA 2140–17), Liquefied Petroleum Gas Specifications and Test Methods, (Revised 2017), IBR approved for § 60.4415(a).

(2) GPA Midstream Standard 2166–17 (GPA 2166–17), Obtaining Natural Gas Samples for Analysis by Gas Chromatography, (Reaffirmed 2017), IBR approved for § 60.4415(a).

* * * * *

(4) GPA Standard 2174–14 (GPA 2174–14), Obtaining Liquid Hydrocarbon Samples for Analysis by Gas Chromatography, (Revised 2014), IBR approved for § 60.4415(a).

(5) GPA Standard 2261–19 (GPA 2261–19), Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography, (Revised 2019), IBR approved for § 60.4415(a).

* * * * *

(l) * * *

(2) ISO 10715:1997(E), Natural gas—Sampling guidelines, (First Edition, June 1, 1997), IBR approved for § 60.4415(a)

* * * * *

Subpart AAA—Standards of Performance for New Residential Wood Heaters

■ 5. Amend § 60.534 by revising paragraph (h) to read as follows:

§ 60.534 What test methods and procedures must I use to determine compliance with the standards and requirements for certification?

* * * * *

(h) The approved test laboratory must allow the manufacturer, the manufacturer's approved third-party certifier, the EPA and delegated state regulatory agencies to observe certification testing. However, manufacturers must not involve themselves in the conduct of the test after the pretest burn has begun. Communications between the manufacturer and laboratory or third-party certifier personnel regarding operation of the wood heater must be limited to written communications transmitted prior to the first pretest burn of the certification test series. During certification tests, the manufacturer may communicate with the third-party certifier, and only in writing, to notify them that the manufacturer has observed a deviation from proper test procedures by the laboratory. All communications must be included in the test documentation required to be submitted pursuant to § 60.533(b)(5) and must be consistent with instructions provided in the owner's manual required under § 60.536(g).

Subpart XXX—Standards of Performance for Municipal Solid Waste Landfills That Commenced Construction, Reconstruction, or Modification After July 17, 2014

■ 6. Amend § 60.766 by revising paragraph (a)(3) to read as follows:

§ 60.766 Monitoring of operations.

* * * * *

(a) * * *

(3) Monitor temperature of the landfill gas on a monthly basis as provided in 60.765(a)(5). The temperature measuring device must be calibrated annually using the procedure in 40 CFR part 60, appendix A–1, Method 2, section 10.3 such that a minimum of two temperature points, bracket within 10 percent of all landfill absolute temperature measurements or two fixed points of ice bath and boiling water, corrected for barometric pressure, are used.

* * * * *

Subpart CCCC—Standards of Performance for Commercial and Industrial Solid Waste Incineration Units

■ 7. Amend § 60.2110 by revising paragraphs (i) introductory text, (i)(1), and (i)(2) introductory text to read as follows:

§ 60.2110 What operating limits must I meet and by when?

* * * * *

(i) If you use a PM CPMS to demonstrate continuing compliance, you must establish your PM CPMS operating limit and determine compliance with it according to paragraphs (i)(1) through (5) of this section:

(1) Determine your operating limit as the average PM CPMS output value recorded during the performance test or at a PM CPMS output value corresponding to 75 percent of the emission limit if your PM performance test demonstrates compliance below 75 percent of the emission limit. You must verify an existing or establish a new operating limit after each repeated performance test. You must repeat the performance test annually and reassess and adjust the site-specific operating limit in accordance with the results of the performance test:

(i) Your PM CPMS must provide a 4–20 milliamp output, or digital equivalent, and the establishment of its relationship to manual reference method measurements must be determined in units of milliamps;

(ii) Your PM CPMS operating range must be capable of reading PM concentrations from zero to a level equivalent to at least two times your allowable emission limit. If your PM CPMS is an auto-ranging instrument capable of multiple scales, the primary range of the instrument must be capable of reading PM concentration from zero to a level equivalent to two times your allowable emission limit; and

(iii) During the initial performance test or any such subsequent performance test that demonstrates compliance with the PM limit, record and average all milliamp output values, or their digital equivalent, from the PM CPMS for the periods corresponding to the compliance test runs (*e.g.,* average all your PM CPMS output values for three corresponding Method 5 or Method 29 test runs).

(2) If the average of your three PM performance test runs are below 75 percent of your PM emissions limit, you must calculate an operating limit by establishing a relationship of PM CPMS signal to PM concentration using the PM CPMS instrument zero, the average PM CPMS output values corresponding to the three compliance test runs, and the average PM concentration from the Method 5 or Method 29 performance test with the procedures in (i)(1) through (5) of this section:

* * * * *

■ 8. Amend § 60.2145 by revising paragraphs (j) introductory text and (y)(3) to read as follows:

§ 60.2145 How do I demonstrate continuous compliance with the emission limitations and the operating limits?

* * * * *

(j) For waste-burning kilns, you must conduct an annual performance test for particulate matter, cadmium, lead, carbon monoxide, dioxins/furans and hydrogen chloride as listed in Table 7 of this subpart, unless you choose to demonstrate initial and continuous compliance using CEMS, as allowed in paragraph (u) of this section. If you do not use an acid gas wet scrubber or dry scrubber, you must determine compliance with the hydrogen chloride emissions limit using a HCl CEMS according to the requirements in paragraph (j)(1) of this section. You must determine compliance with the mercury emissions limit using a mercury CEMS or an integrated sorbent trap monitoring system according to paragraph (j)(2) of this section. You must determine compliance with nitrogen oxides and sulfur dioxide using CEMS. You must determine continuing compliance with the particulate matter emissions limit using a PM CPMS according to paragraph (x) of this section.

* * * * *

(y) * * *

(3) For purposes of determining the combined emissions from kilns equipped with an alkali bypass or that exhaust kiln gases to a coal mill that exhausts through a separate stack, instead of installing a CEMS or PM CPMS on the alkali bypass stack or in-line coal mill stack, the results of the initial and subsequent performance test can be used to demonstrate compliance with the relevant emissions limit. A performance test must be conducted on an annual basis (no later than 13 calendar months following the previous performance test).

■ 9. Revise § 60.2150 to read as follows:

§ 60.2150 By what date must I conduct the annual performance test?

You must conduct annual performance tests no later than 13 calendar months following the previous performance test.

■ 10. Amend § 60.2210 by revising the introductory text and adding paragraph (p) to read as follows:

§ 60.2210 What information must I include in my annual report?

The annual report required under § 60.2205 must include the items listed in paragraphs (a) through (p) of this section. If you have a deviation from the operating limits or the emission limitations, you must also submit deviation reports as specified in §§ 60.2215, 60.2220, and 60.2225:

* * * * *

(p) For energy recovery units, include the annual heat input and average annual heat input rate of all fuels being burned in the unit to verify which subcategory of energy recovery unit applies.

■ 11. Table 6 to subpart CCCC of part 60 is revised to read as follows:

TABLE 6 TO SUBPART CCCC OF PART 60—EMISSION LIMITATIONS FOR ENERGY RECOVERY UNITS THAT COMMENCED CONSTRUCTION AFTER JUNE 4, 2010, OR THAT COMMENCED RECONSTRUCTION OR MODIFICATION AFTER AUGUST 7, 2013

For the air pollutant	You must meet this emission limitation [1]		Using this averaging time [2]	And determining compliance using this method [2]
	Liquid/gas	Solids		
Cadmium	0.023 milligrams per dry standard cubic meter.	Biomass—0.0014 milligrams per dry standard cubic meter. Coal—0.0017 milligrams per dry standard cubic meter.	3-run average (collect a minimum volume of 4 dry standard cubic meters per run).	Performance test (Method 29 at 40 CFR part 60, appendix A–8). Use ICPMS for the analytical finish.
Carbon monoxide	35 parts per million dry volume	Biomass—240 parts per million dry volume. Coal—95 parts per million dry volume.	3-run average (1 hour minimum sample time per run).	Performance test (Method 10 at 40 CFR part 60, appendix A–4).
Dioxin/furans (Total Mass Basis).	No Total Mass Basis limit, must meet the toxic equivalency basis limit below.	Biomass—0.52 nanograms per dry standard cubic meter. Coal—5.1 nanograms per dry standard cubic meter.	3-run average (collect a minimum volume of 4 dry standard cubic meters).	Performance test (Method 23 at 40 CFR part 60, appendix A–7).
Dioxins/furans (toxic equivalency basis).	0.093 nanograms per dry standard cubic meter.	Biomass—0.076 nanograms per dry standard cubic meter.[3] Coal—0.075 nanograms per dry standard cubic meter.	3-run average (collect a minimum volume of 4 dry standard cubic meters per run).	Performance test (Method 23 of appendix A–7 of this part).
Fugitive ash	Visible emissions for no more than 5 percent of the hourly observation period.	Three 1-hour observation periods.	Visible emission test (Method 22 at 40 CFR part 60, appendix A–7).	Fugitive ash.
Hydrogen chloride	14 parts per million dry volume	Biomass—0.20 parts per million dry volume. Coal—58 parts per million dry volume.	3-run average (For Method 26, collect a minimum volume of 360 liters per run. For Method 26A, collect a minimum volume of 3 dry standard cubic meters per run).	Performance test (Method 26 or 26A at 40 CFR part 60, appendix A–8).

TABLE 6 TO SUBPART CCCC OF PART 60—EMISSION LIMITATIONS FOR ENERGY RECOVERY UNITS THAT COMMENCED CONSTRUCTION AFTER JUNE 4, 2010, OR THAT COMMENCED RECONSTRUCTION OR MODIFICATION AFTER AUGUST 7, 2013—Continued

For the air pollutant	You must meet this emission limitation [1]		Using this averaging time [2]	And determining compliance using this method [2]
	Liquid/gas	Solids		
Lead	0.096 milligrams per dry standard cubic meter.	Biomass—0.014 milligrams per dry standard cubic meter. Coal—0.057 milligrams per dry standard cubic meter.	3-run average (collect a minimum volume of 4 dry standard cubic meters per run).	Performance test (Method 29 at 40 CFR part 60, appendix A–8). Use ICPMS for the analytical finish.
Mercury	0.00056 milligrams per dry standard cubic meter.	Biomass—0.0022 milligrams per dry standard cubic meter. Coal—0.013 milligrams per dry standard cubic meter.	3-run average (collect enough volume to meet an in-stack detection limit data quality objective of 0.03 ug/dscm).	Performance test (Method 29 or 30B at 40 CFR part 60, appendix A–8) or ASTM D6784–02 (Reapproved 2008).[3]
Nitrogen oxides	76 parts per million dry volume	Biomass—290 parts per million dry volume. Coal—460 parts per million dry volume.	3-run average (for Method 7E, 1 hour minimum sample time per run).	Performance test (Method 7 or 7E at 40 CFR part 60, appendix A–4).
Particulate matter (filterable).	110 milligrams per dry standard cubic meter.	Biomass—5.1 milligrams per dry standard cubic meter. Coal—130 milligrams per dry standard cubic meter.	3-run average (collect a minimum volume of 1 dry standard cubic meter per run).	Performance test (Method 5 or 29 at 40 CFR part 60, appendix A–3 or appendix A–8).
Sulfur dioxide	720 parts per million dry volume	Biomass—7.3 parts per million dry volume. Coal—850 parts per million dry volume.	3-run average (for Method 6, collect a minimum of 60 liters, for Method 6C, 1 hour minimum sample time per run).	Performance test (Method 6 or 6C at 40 CFR part 60, appendix A–4).

[1] All emission limitations are measured at 7 percent oxygen, dry basis at standard conditions. For dioxins/furans, you must meet either the Total Mass Basis limit or the toxic equivalency basis limit.

[2] In lieu of performance testing, you may use a CEMS or, for mercury, an integrated sorbent trap monitoring system to demonstrate initial and continuing compliance with an emissions limit, as long as you comply with the CEMS or integrated sorbent trap monitoring system requirements applicable to the specific pollutant in §§ 60.2145 and 60.2165. As prescribed in § 60.2145(u), if you use a CEMS or an integrated sorbent trap monitoring system to demonstrate compliance with an emissions limit, your averaging time is a 30-day rolling average of 1-hour arithmetic average emission concentrations.

[3] Incorporated by reference, *see* § 60.17.

■ 12. Table 7 to subpart CCCC of part 60 is revised to read as follows:

TABLE 7 TO SUBPART CCCC OF PART 60—EMISSION LIMITATIONS FOR WASTE-BURNING KILNS THAT COMMENCED CONSTRUCTION AFTER JUNE 4, 2010, OR RECONSTRUCTION OR MODIFICATION AFTER AUGUST 7, 2013

For the air pollutant	You must meet this emission limitation [1]	Using this averaging time [2]	And determining compliance using this method [2,3]
Cadmium	0.0014 milligrams per dry standard cubic meter.	3-run average (collect a minimum volume of 4 dry standard cubic meters per run).	Performance test (Method 29 at 40 CFR part 60, appendix A–8). Use ICPMS for the analytical finish.
Carbon monoxide	90 (long kilns)/190 (preheater/precalciner) parts per million dry volume.	3-run average (1 hour minimum sample time per run).	Performance test (Method 10 at 40 CFR part 60, appendix A–4).
Dioxins/furans (total mass basis).	0.51 nanograms per dry standard cubic meter.	3-run average (collect a minimum volume of 4 dry standard cubic meters per run).	Performance test (Method 23 at 40 CFR part 60, appendix A–7).
Dioxins/furans (toxic equivalency basis).	0.075 nanograms per dry standard cubic meter.	3-run average (collect a minimum volume of 4 dry standard cubic meters).	Performance test (Method 23 at 40 CFR part 60, appendix A–7).
Hydrogen chloride	3.0 parts per million dry volume	3-run average (1 hour minimum sample time per run) or 30-day rolling average if HCl CEMS is being used.	If a wet scrubber or dry scrubber is used, performance test (Method 321 at 40 CFR part 63, appendix A). If a wet scrubber or dry scrubber is not used, HCl CEMS as specified in § 60.2145(j).
Lead	0.014 milligrams per dry standard cubic meter.	3-run average (collect a minimum volume of 4 dry standard cubic meters).	Performance test (Method 29 at 40 CFR part 60, appendix A–8). Use ICPMS for the analytical finish.
Mercury	0.0037 milligrams per dry standard cubic meter. *Or* 21 pounds/million tons of clinker[3].	30-day rolling average	Mercury CEMS or integrated sorbent trap monitoring system (performance specification 12A or 12B, respectively, of appendix B and procedure 5 of appendix F of this part), as specified in § 60.2145(j).
Nitrogen oxides	200 parts per million dry volume	30-day rolling average	Nitrogen oxides CEMS (performance specification 2 of appendix B and procedure 1 of appendix F of this part).
Particulate matter (filterable).	4.9 milligrams per dry standard cubic meter	3-run average (collect a minimum volume of 2 dry standard cubic meters).	Performance test (Method 5 or 29 at 40 CFR part 60, appendix A–3 or appendix–8).
Sulfur dioxide	28 parts per million dry volume	30-day rolling average	Sulfur dioxide CEMS (performance specification 2 of appendix B and procedure 1 of appendix F of this part).

[1] All emission limitations are measured at 7 percent oxygen (except for CEMS and integrated sorbent trap monitoring system data during startup and shutdown), dry basis at standard conditions. For dioxins/furans, you must meet either the Total Mass Basis limit or the toxic equivalency basis limit.

[2] In lieu of performance testing, you may use a CEMS or, for mercury, an integrated sorbent trap monitoring system, to demonstrate initial and continuing compliance with an emissions limit, as long as you comply with the CEMS or integrated sorbent trap monitoring system requirements applicable to the specific pollutant in §§ 60.2145 and 60.2165. As prescribed in § 60.2145(u), if you use a CEMS or integrated sorbent trap monitoring system to demonstrate compliance with an emissions limit, your averaging time is a 30-day rolling average of 1-hour arithmetic average emission concentrations.

[3] Alkali bypass and in-line coal mill stacks are subject to performance testing only, as specified in § 60.2145(y)(3). They are not subject to the CEMS, integrated sorbent trap monitoring system, or CPMS requirements that otherwise may apply to the main kiln exhaust.

Subpart DDDD—Emission Guidelines and Compliance Times for Commercial and Industrial Solid Waste Incineration Units

■ 13. Amend § 60.2675 by revising the introductory text to paragraphs (i) introductory text, (i)(1), and (i)(2) introductory text to read as follows:

§ 60.2675 What operating limits must I meet and by when?

* * * * *

(i) If you use a PM CPMS to demonstrate continuing compliance, you must establish your PM CPMS operating limit and determine compliance with it according to paragraphs (i)(1) through (5) of this section:

(1) During the initial performance test or any such subsequent performance test that demonstrates compliance with the PM limit, record all hourly average output values (milliamps, or the digital signal equivalent) from the PM CPMS for the periods corresponding to the test runs (*e.g.,* three 1-hour average PM CPMS output values for three 1-hour test runs):

(i) Your PM CPMS must provide a 4–20 milliamp output, or the digital signal equivalent, and the establishment of its relationship to manual reference method measurements must be determined in units of milliamps or digital bits;

(ii) Your PM CPMS operating range must be capable of reading PM concentrations from zero to a level equivalent to at least two times your allowable emission limit. If your PM CPMS is an auto-ranging instrument capable of multiple scales, the primary range of the instrument must be capable of reading PM concentration from zero to a level equivalent to two times your allowable emission limit; and

(iii) During the initial performance test or any such subsequent performance test that demonstrates compliance with the PM limit, record and average all milliamp output values, or their digital equivalent, from the PM CPMS for the periods corresponding to the compliance test runs (*e.g.,* average all your PM CPMS output values for the three corresponding Method 5 or Method 29 p.m. test runs).

(2) If the average of your three PM performance test runs are below 75 percent of your PM emission limit, you must calculate an operating limit by establishing a relationship of PM CPMS signal to PM concentration using the PM CPMS instrument zero, the average PM CPMS output values corresponding to the three compliance test runs, and the average PM concentration from the Method 5 or Method 29 performance test with the procedures in (i)(1)through (5) of this section:

* * * * *

■ 14. Amend § 60.2710 by revising paragraphs (j) introductory text and (y)(3) to read as follows:

§ 60.2710 How do I demonstrate continuous compliance with the amended emission limitations and the operating limits?

* * * * *

(j) For waste-burning kilns, you must conduct an annual performance test for the pollutants (except mercury and hydrogen chloride if no acid gas wet scrubber or dry scrubber is used) listed in Table 8 of this subpart, unless you choose to demonstrate initial and continuous compliance using CEMS, as allowed in paragraph (u) of this section. If you do not use an acid gas wet scrubber or dry scrubber, you must determine compliance with the hydrogen chloride emissions limit using a HCl CEMS according to the requirements in paragraph (j)(1) of this section. You must determine compliance with the mercury emissions limit using a mercury CEMS or an integrated sorbent trap monitoring system according to paragraph (j)(2) of this section. You must determine continuing compliance with particulate matter using a PM CPMS according to paragraph (x) of this section.

* * * * *

(y) * * *

(3) For purposes of determining the combined emissions from kilns equipped with an alkali bypass or that exhaust kiln gases to a coal mill that exhausts through a separate stack, instead of installing a CEMS or PM CPMS on the alkali bypass stack or in-line coal mill stack, the results of the initial and subsequent performance test can be used to demonstrate compliance with the relevant emissions limit. A performance test must be conducted on an annual basis (no later than 13 calendar months following the previous performance test).

■ 15. Revise § 60.2715 to read as follows:

§ 60.2715 By what date must I conduct the annual performance test?

You must conduct annual performance tests no later than 13 calendar months following the previous performance test.

■ 16. Table 7 to subpart DDDD of part 60 is revised to read as follows:

TABLE 7 TO SUBPART DDDD OF PART 60—MODEL RULE—EMISSION LIMITATIONS THAT APPLY TO ENERGY RECOVERY UNITS AFTER MAY 20, 2011

[Date to be specified in state plan][1]

For the air pollutant	You must meet this emission limitation[2]		Using this averaging time[3]	And determining compliance using this method[3]
	Liquid/gas	Solids		
Cadmium	0.023 milligrams per dry standard cubic meter.	Biomass—0.0014 milligrams per dry standard cubic meter. Coal—0.0017 milligrams per dry standard cubic meter.	3-run average (collect a minimum volume of 2 dry standard cubic meters).	Performance test (Method 29 at 40 CFR part 60, appendix A–8). Use ICPMS for the analytical finish.
Carbon monoxide	35 parts per million dry volume	Biomass—260 parts per million dry volume. Coal—95 parts per million dry volume.	3-run average (1 hour minimum sample time per run).	Performance test (Method 10 at 40 CFR part 60, appendix A–4).
Dioxins/furans (total mass basis).	2.9 nanograms per dry standard cubic meter.	Biomass—0.52 nanograms per dry standard cubic meter. Coal—5.1 nanograms per dry standard cubic meter.	3-run average (collect a minimum volume of 4 dry standard cubic meter).	Performance test (Method 23 at 40 CFR part 60, appendix A–7).
Dioxins/furans (toxic equivalency basis).	0.32 nanograms per dry standard cubic meter.	Biomass—0.12 nanograms per dry standard cubic meter. Coal—0.075 nanograms per dry standard cubic meter.	3-run average (collect a minimum volume of 4 dry standard cubic meters).	Performance test (Method 23 at 40 CFR part 60, appendix A–7).
Hydrogen chloride	14 parts per million dry volume	Biomass—0.20 parts per million dry volume. Coal—58 parts per million dry volume.	3-run average (for Method 26, collect a minimum of 120 liters; for Method 26A, collect a minimum volume of 1 dry standard cubic meter).	Performance test (Method 26 or 26A at 40 CFR part 60, appendix A–8).

TABLE 7 TO SUBPART DDDD OF PART 60—MODEL RULE—EMISSION LIMITATIONS THAT APPLY TO ENERGY RECOVERY UNITS AFTER MAY 20, 2011—Continued

[Date to be specified in state plan] [1]

For the air pollutant	You must meet this emission limitation [2]		Using this averaging time [3]	And determining compliance using this method [3]
	Liquid/gas	Solids		
Lead	0.096 milligrams per dry standard cubic meter.	Biomass—0.014 milligrams per dry standard cubic meter. Coal—0.057 milligrams per dry standard cubic meter.	3-run average (collect a minimum volume of 2 dry standard cubic meters).	Performance test (Method 29 at 40 CFR part 60, appendix A–8). Use ICPMS for the analytical finish.
Mercury	0.0024 milligrams per dry standard cubic meter.	Biomass—0.0022 milligrams per dry standard cubic meter. Coal—0.013 milligrams per dry standard cubic meter.	3-run average (For Method 29 and ASTM D6784–02 (Reapproved 2008) [4], collect a minimum volume of 2 dry standard cubic meters per run. For Method 30B, collect a minimum sample as specified in Method 30B at 40 CFR part 60, appendix A).	Performance test (Method 29 or 30B at 40 CFR part 60, appendix A–8) or ASTM D6784–02 (Reapproved 2008).[4]
Nitrogen oxides	76 parts per million dry volume	Biomass—290 parts per million dry volume. Coal—460 parts per million dry volume.	3-run average (for Method 7E, 1 hour minimum sample time per run).	Performance test (Method 7 or 7E at 40 CFR part 60, appendix A–4).
Particulate matter filterable.	110 milligrams per dry standard cubic meter.	Biomass—11 milligrams per dry standard cubic meter. Coal—130 milligrams per dry standard cubic meter.	3-run average (collect a minimum volume of 1 dry standard cubic meter).	Performance test (Method 5 or 29 at 40 CFR part 60, appendix A–3 or appendix A–8).
Sulfur dioxide	720 parts per million dry volume	Biomass—7.3 parts per million dry volume. Coal—850 parts per million dry volume.	3-run average (1 hour minimum sample time per run).	Performance test (Method 6 or 6c at 40 CFR part 60, appendix A–4).
Fugitive ash	Visible emissions for no more than 5 percent of the hourly observation period.	Visible emissions for no more than 5 percent of the hourly observation period.	Three 1-hour observation periods.	Visible emission test (Method 22 at 40 CFR part 60, appendix A–7).

[1] The date specified in the state plan can be no later than 3 years after the effective date of approval of a revised state plan or February 7, 2018.

[2] All emission limitations (except for opacity) are measured at 7 percent oxygen, dry basis at standard conditions. For dioxins/furans, you must meet either the total mass basis limit or the toxic equivalency basis limit.

[3] In lieu of performance testing, you may use a CEMS or, for mercury, an integrated sorbent trap monitoring system, to demonstrate initial and continuing compliance with an emissions limit, as long as you comply with the CEMS or integrated sorbent trap monitoring system requirements applicable to the specific pollutant in §§ 60.2710 and 60.2730. As prescribed in § 60.2710(u), if you use a CEMS or integrated sorbent trap monitoring system to demonstrate compliance with an emissions limit, your averaging time is a 30-day rolling average of 1-hour arithmetic average emission concentrations.

[4] Incorporated by reference, see § 60.17.

■ 17. Table 8 to subpart DDDD of part 60 is revised to read as follows:

TABLE 8 TO SUBPART DDDD OF PART 60—MODEL RULE—EMISSION LIMITATIONS THAT APPLY TO WASTE-BURNING KILNS AFTER MAY 20, 2011

[Date to be specified in state plan] [1]

For the air pollutant	You must meet this emission limitation [2]	Using this averaging time [3]	And determining compliance using this method [3 4]
Cadmium	0.0014 milligrams per dry standard cubic meter.	3-run average (collect a minimum volume of 2 dry standard cubic meters).	Performance test (Method 29 at 40 CFR part 60, appendix A–8).
Carbon monoxide	110 (long kilns)/790 (preheater/precalciner) parts per million dry volume.	3-run average (1 hour minimum sample time per run).	Performance test (Method 10 at 40 CFR part 60, appendix A–4).
Dioxins/furans (total mass basis).	1.3 nanograms per dry standard cubic meter	3-run average (collect a minimum volume of 4 dry standard cubic meters).	Performance test (Method 23 at 40 CFR part 60, appendix A–7).
Dioxins/furans (toxic equivalency basis).	0.075 nanograms per dry standard cubic meter.	3-run average (collect a minimum volume of 4 dry standard cubic meters).	Performance test (Method 23 at 40 CFR part 60, appendix A–7).
Hydrogen chloride	3.0 parts per million dry volume	3-run average (collect a minimum volume of 1 dry standard cubic meter), or 30-day rolling average if HCl CEMS is being used.	If a wet scrubber or dry scrubber is used, performance test (Method 321 at 40 CFR part 63, appendix A of this part). If a wet scrubber or dry scrubber is not used, HCl CEMS as specified in § 60.2710(j).
Lead	0.014 milligrams per dry standard cubic meter.	3-run average (collect a minimum volume of 2 dry standard cubic meters).	Performance test (Method 29 at 40 CFR part 60, appendix A–8).
Mercury	0.011 milligrams per dry standard cubic meter. *Or* 58 pounds/million tons of clinker.	30-day rolling average	Mercury CEMS or integrated sorbent trap monitoring system (performance specification 12A or 12B, respectively, of appendix B and procedure 5 of appendix F of this part), as specified in § 60.2710(j).
Nitrogen oxides	630 parts per million dry volume	3-run average (for Method 7E, 1 hour minimum sample time per run).	Performance test (Method 7 or 7E at 40 CFR part 60, appendix A–4).
Particulate matter filterable.	13.5 milligrams per dry standard cubic meter	3-run average (collect a minimum volume of 1 dry standard cubic meter).	Performance test (Method 5 or 29 at 40 CFR part 60, appendix A–3 or appendix–8).

TABLE 8 TO SUBPART DDDD OF PART 60—MODEL RULE—EMISSION LIMITATIONS THAT APPLY TO WASTE-BURNING KILNS AFTER MAY 20, 2011—Continued

[Date to be specified in state plan] [1]

For the air pollutant	You must meet this emission limitation [2]	Using this averaging time [3]	And determining compliance using this method [3 4]
Sulfur dioxide	600 parts per million dry volume	3-run average (for Method 6, collect a minimum of 20 liters; for Method 6C, 1 hour minimum sample time per run).	Performance test (Method 6 or 6c at 40 CFR part 60, appendix A–4).

[1] The date specified in the state plan can be no later than 3 years after the effective date of approval of a revised state plan or February 7, 2018.
[2] All emission limitations are measured at 7 percent oxygen (except for CEMS and integrated sorbent trap monitoring system data during startup and shutdown), dry basis at standard conditions. For dioxins/furans, you must meet either the total mass basis limit or the toxic equivalency basis limit.
[3] In lieu of performance testing, you may use a CEMS or, for mercury, an integrated sorbent trap monitoring system, to demonstrate initial and continuing compliance with an emissions limit, as long as you comply with the CEMS or integrated sorbent trap monitoring system requirements applicable to the specific pollutant in §§ 60.2710 and 60.2730. As prescribed in § 60.2710(u), if you use a CEMS or integrated sorbent trap monitoring system to demonstrate compliance with an emissions limit, your averaging time is a 30-day rolling average of 1-hour arithmetic average emission concentrations.
[4] Alkali bypass and in-line coal mill stacks are subject to performance testing only, as specified in § 60.2710(y)(3). They are not subject to the CEMS, integrated sorbent trap monitoring system, or CPMS requirements that otherwise may apply to the main kiln exhaust.

Subpart JJJJ—Standards of Performance for Stationary Spark Ignition Internal Combustion Engines

■ 18. Table 2 to subpart JJJJ of part 60 is revised to read as follows:

As stated in § 60.4244, you must comply with the following requirements for performance tests within 10 percent of 100 percent peak (or the highest achievable) load].

TABLE 2 TO SUBPART JJJJ OF PART 60—REQUIREMENTS FOR PERFORMANCE TESTS

For each	Complying with the requirement to	You must	Using	According to the following requirements
1. Stationary SI internal combustion engine demonstrating compliance according to § 60.4244.	a. Limit the concentration of NO_X in the stationary SI internal combustion engine exhaust.	i. Select the sampling port location and the number/location of traverse points at the exhaust of the stationary internal combustion engine;	(1) Method 1 or 1A of 40 CFR part 60, appendix A–1, if measuring flow rate.	(a) Alternatively, for NO_X, O_2, and moisture measurement, ducts ≤6 inches in diameter may be sampled at a single point located at the duct centroid and ducts >6 and ≤12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line ('3-point long line'). If the duct is >12 inches in diameter *and* the sampling port location meets the two and half-diameter criterion of Section 11.1.1 of Method 1 of 40 CFR part 60, Appendix A, the duct may be sampled at '3-point long line'; otherwise, conduct the stratification testing and select sampling points according to Section 8.1.2 of Method 7E of 40 CFR part 60, Appendix A.
		ii. Determine the O_2 concentration of the stationary internal combustion engine exhaust at the sampling port location;	(2) Method 3, 3A, or 3B [b] of 40 CFR part 60, appendix A–2 or ASTM Method D6522–00 (Reapproved 2005) [a d].	(b) Measurements to determine O_2 concentration must be made at the same time as the measurements for NO_X concentration.
		iii. If necessary, determine the exhaust flowrate of the stationary internal combustion engine exhaust;	(3) Method 2 or 2C of 40 CFR part 60, appendix A–1 or Method 19 of 40 CFR part 60, appendix A–7.	(c) Measurements to determine the exhaust flowrate must be made (1) at the same time as the measurement for NO_X concentration or, alternatively (2) according to the option in Section 11.1.2 of Method 1A of 40 CFR part 60, Appendix A–1, if applicable.
		iv. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the sampling port location; and	(4) Method 4 of 40 CFR part 60, appendix A–3, Method 320 of 40 CFR part 63, appendix A,[e] or ASTM Method D6348–03 [d e].	(d) Measurements to determine moisture must be made at the same time as the measurement for NO_X concentration.
		v. Measure NO_X at the exhaust of the stationary internal combustion engine; if using a control device, the sampling site must be located at the outlet of the control device	(5) Method 7E of 40 CFR part 60, appendix A–4, ASTM Method D6522–00 (Reapproved 2005),[a d] Method 320 of 40 CFR part 63, appendix A,[e] or ASTM Method D6348–03 [d e].	(e) Results of this test consist of the average of the three 1-hour or longer runs.

TABLE 2 TO SUBPART JJJJ OF PART 60—REQUIREMENTS FOR PERFORMANCE TESTS—Continued

For each	Complying with the requirement to	You must	Using	According to the following requirements
	b. Limit the concentration of CO in the stationary SI internal combustion engine exhaust.	i. Select the sampling port location and the number/location of traverse points at the exhaust of the stationary internal combustion engine;	(1) Method 1 or 1A of 40 CFR part 60, appendix A–1, if measuring flow rate.	(a) Alternatively, for CO, O_2, and moisture measurement, ducts ≤6 inches in diameter may be sampled at a single point located at the duct centroid and ducts >6 and ≤12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line ('3-point long line'). If the duct is >12 inches in diameter *and* the sampling port location meets the two and half-diameter criterion of Section 11.1.1 of Method 1 of 40 CFR part 60, Appendix A, the duct may be sampled at '3-point long line'; otherwise, conduct the stratification testing and select sampling points according to Section 8.1.2 of Method 7E of 40 CFR part 60, Appendix A.
		ii. Determine the O_2 concentration of the stationary internal combustion engine exhaust at the sampling port location;	(2) Method 3, 3A, or 3B [b] of 40 CFR part 60, appendix A–2 or ASTM Method D6522–00 (Reapproved 2005) [a d].	(b) Measurements to determine O_2 concentration must be made at the same time as the measurements for CO concentration.
		iii. If necessary, determine the exhaust flowrate of the stationary internal combustion engine exhaust;	(3) Method 2 or 2C of 40 CFR 60, appendix A–1 or Method 19 of 40 CFR part 60, appendix A–7.	(c) Measurements to determine the exhaust flowrate must be made (1) at the same time as the measurement for CO concentration or, alternatively (2) according to the option in Section 11.1.2 of Method 1A of 40 CFR part 60, Appendix A–1, if applicable.
		iv. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the sampling port location; and	(4) Method 4 of 40 CFR part 60, appendix A–3, Method 320 of 40 CFR part 63, appendix A,[e] or ASTM Method D6348–03 [d e].	(d) Measurements to determine moisture must be made at the same time as the measurement for CO concentration.
		v. Measure CO at the exhaust of the stationary internal combustion engine; if using a control device, the sampling site must be located at the outlet of the control device	(5) Method 10 of 40 CFR part 60, appendix A4, ASTM Method D6522–00 (Reapproved 2005),[a d e] Method 320 of 40 CFR part 63, appendix A,[e] or ASTM Method D6348–03 [d e].	(e) Results of this test consist of the average of the three 1-hour or longer runs.
	c. Limit the concentration of VOC in the stationary SI internal combustion engine exhaust.	i. Select the sampling port location and the number/location of traverse points at the exhaust of the stationary internal combustion engine;	(1) Method 1 or 1A of 40 CFR part 60, appendix A–1, if measuring flow rate.	(a) Alternatively, for VOC, O_2, and moisture measurement, ducts ≤6 inches in diameter may be sampled at a single point located at the duct centroid and ducts >6 and ≤12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line ('3-point long line'). If the duct is >12 inches in diameter *and* the sampling port location meets the two and half-diameter criterion of Section 11.1.1 of Method 1 of 40 CFR part 60, Appendix A, the duct may be sampled at '3-point long line'; otherwise, conduct the stratification testing and select sampling points according to Section 8.1.2 of Method 7E of 40 CFR part 60, Appendix A.
		ii. Determine the O_2 concentration of the stationary internal combustion engine exhaust at the sampling port location;	(2) Method 3, 3A, or 3B [b] of 40 CFR part 60, appendix A–2 or ASTM Method D6522–00 (Reapproved 2005) [a d].	(b) Measurements to determine O_2 concentration must be made at the same time as the measurements for VOC concentration.
		iii. If necessary, determine the exhaust flowrate of the stationary internal combustion engine exhaust;	(3) Method 2 or 2C of 40 CFR 60, appendix A–1 or Method 19 of 40 CFR part 60, appendix A–7.	(c) Measurements to determine the exhaust flowrate must be made (1) at the same time as the measurement for VOC concentration or, alternatively (2) according to the option in Section 11.1.2 of Method 1A of 40 CFR part 60, Appendix A–1, if applicable.

TABLE 2 TO SUBPART JJJJ OF PART 60—REQUIREMENTS FOR PERFORMANCE TESTS—Continued

For each	Complying with the requirement to	You must	Using	According to the following requirements
		iv. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the sampling port location; and	(4) Method 4 of 40 CFR part 60, appendix A–3, Method 320 of 40 CFR part 63, appendix A,[e] or ASTM Method D6348–03[d e].	(d) Measurements to determine moisture must be made at the same time as the measurement for VOC concentration.
		v. Measure VOC at the exhaust of the stationary internal combustion engine; if using a control device, the sampling site must be located at the outlet of the control device	(5) Methods 25A and 18 of 40 CFR part 60, appendices A–6 and A–7, Method 25A with the use of a hydrocarbon cutter as described in 40 CFR 1065.265, Method 18 of 40 CFR part 60, appendix A–6,[c e] Method 320 of 40 CFR part 63, appendix A,[e] or ASTM Method D6348–03[d e].	(e) Results of this test consist of the average of the three 1-hour or longer runs.

[a] Also, you may petition the Administrator for approval to use alternative methods for portable analyzer.
[b] You may use ASME PTC 19.10–1981, Flue and Exhaust Gas Analyses, for measuring the O_2 content of the exhaust gas as an alternative to EPA Method 3B. AMSE PTC 19.10–1981 incorporated by reference, see 40 CFR 60.17
[c] You may use EPA Method 18 of 40 CFR part 60, appendix A–6, provided that you conduct an adequate pre-survey test prior to the emissions test, such as the one described in OTM 11 on EPA's website (*http://www.epa.gov/ttn/emc/prelim/otm11.pdf*).
[d] Incorporated by reference; see 40 CFR 60.17.
[e] You must meet the requirements in § 60.4245(d).

Subpart KKKK—Standards of Performance for Stationary Combustion Turbines

■ 19. Amend § 60.4415 by revising paragraph (a) introductory text, redesignating paragraphs (a)(1) through (3) as paragraphs (a)(2) through (4), adding new paragraph (a)(1), and revising the newly redesignated paragraph (a)(2) to read as follows:

§ 60.4415 How do I conduct the initial and subsequent performance tests for sulfur?

(a) You must conduct an initial performance test, as required in § 60.8. Subsequent SO_2 performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test). There are four methodologies that you may use to conduct the performance tests.

(1) The use of a current, valid purchase contract, tariff sheet, or transportation contract for the fuel specifying the maximum total sulfur content of all fuels combusted in the affected facility. Alternately, the fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of appendix D to part 75 of this chapter may be used.

(2) Periodically determine the sulfur content of the fuel combusted in the turbine, a representative fuel sample may be collected either by an automatic sampling system or manually. For automatic sampling, follow ASTM D5287 (incorporated by reference, see § 60.17) for gaseous fuels or ASTM D4177 (incorporated by reference, see § 60.17) for liquid fuels. For manual sampling of gaseous fuels, follow API Manual of Petroleum Measurement Standards, Chapter 14, Section 1, GPA 2166, or ISO 10715 (all incorporated by reference, see § 60.17). For manual sampling of liquid fuels, follow GPA 2174 or the procedures for manual pipeline sampling in section 14 of ASTM D4057 (both incorporated by reference, see § 60.17). The fuel analyses of this section may be performed either by you, a service contractor retained by you, the fuel vendor, or any other qualified agency. Analyze the samples for the total sulfur content of the fuel using:

(i) For liquid fuels, ASTM D129, or alternatively D1266, D1552, D2622, D4294, D5453, D5623, or D7039 (all incorporated by reference, see § 60.17); or

(ii) For gaseous fuels, ASTM D1072, or alternatively D3246, D4084, D4468, D4810, D6228, D6667, or GPA 2140, 2261, or 2377 (all incorporated by reference, see § 60.17).

* * * * *

Subpart QQQQ—Standards of Performance for New Residential Hydronic Heaters and Forced-Air Furnaces

■ 20. Amend § 60.5476 by revising paragraph (i) to read as follows:

§ 60.5476 What test methods and procedures must I use to determine compliance with the standards and requirements for certification?

* * * * *

(i) The approved test laboratory must allow the manufacturer, the manufacturer's approved third-party certifier, the EPA and delegated state regulatory agencies to observe certification testing. However, manufacturers must not involve themselves in the conduct of the test after the pretest burn has begun. Communications between the manufacturer and laboratory or third-party certifier personnel regarding operation of the central heater must be limited to written communications transmitted prior to the first pretest burn of the certification test series. During certification tests, the manufacturer may communicate with the third-party certifier, and only in writing to notify them that the manufacturer has observed a deviation from proper test procedures by the laboratory. All communications must be included in the test documentation required to be submitted pursuant to § 60.5475(b)(5) and must be consistent with instructions provided in the owner's manual required under § 60.5478(f).

■ 21. Amend Appendix A–3 to part 60 by:

■ a. In Method 4, revising sections "2.1", "6.1.5", "8.1.2.1", "8.1.3", "8.1.3.2.1", "8.1.3.2.2", "8.1.4.2", "9.1", "11.1", "11.2", "12.1.1", "12.1.2", "12.1.3", "12.2.1", and "12.2.2" and "Figure 4–4" and "Figure 4–5"; and

■ b. In Method 5, revising sections "6.1.1.8", "6.2.4", "6.2.5", "8.1.2", "8.7.6.4", "12.1", "12.3", "12.4", "12.11.1", "12.11.2", "16.1.1.4", and "16.2.3.3" and "Figure 5–6".

The revisions read as follows:

Appendix A–3 to Part 60—Test Methods 4 Through 5I

* * * * *

Method 4—Determination of Moisture Content in Stack Gases

* * * * *

2.1 A gas sample is extracted at a constant rate from the source; moisture is removed from the sample stream and determined gravimetrically.

* * * * *

6.1.5 Barometer and Balance. Same as Method 5, sections 6.1.2 and 6.2.5, respectively.

* * * * *

8.1.2.1 Transfer water into the first two impingers, leave the third impinger empty and add silica gel to the fourth impinger. Weigh the impingers before sampling and record the weight to the nearest 0.5g at a minimum.

* * * * *

8.1.3 Leak-Check Procedures.

8.1.3.1 Leak Check of Metering System Shown in Figure 4–1. That portion of the sampling train from the pump to the orifice meter should be leak-checked prior to initial use and after each shipment. Leakage after the pump will result in less volume being recorded than is actually sampled. The following procedure is suggested (see Figure 5–2 of Method 5): Close the main valve on the meter box. Insert a one-hole rubber stopper with rubber tubing attached into the orifice exhaust pipe. Disconnect and vent the low side of the orifice manometer. Close off the low side orifice tap. Pressurize the system to 13 to 18 cm (5 to 7 in.) water column by blowing into the rubber tubing. Pinch off the tubing and observe the manometer for one minute. A loss of pressure on the manometer indicates a leak in the meter box; leaks, if present, must be corrected.

8.1.3.2 Pretest Leak Check. A pretest leak check of the sampling train is recommended, but not required. If the pretest leak check is conducted, the following procedure should be used.

8.1.3.2.1 After the sampling train has been assembled, turn on and set the filter and probe heating systems to the desired operating temperatures. Allow time for the temperatures to stabilize.

8.1.3.2.2 Leak-check the train by first plugging the inlet to the filter holder and pulling a 380 mm (15 in.) Hg vacuum. Then connect the probe to the train, and leak-check at approximately 25 mm (1 in.) Hg vacuum; alternatively, the probe may be leak-checked with the rest of the sampling train, in one step, at 380 mm (15 in.) Hg vacuum. Leakage rates in excess of 4 percent of the average sampling rate or 0.00057 m^3/min (0.020 cfm), whichever is less, are unacceptable.

8.1.3.2.3 Start the pump with the bypass valve fully open and the coarse adjust valve completely closed. Partially open the coarse adjust valve, and slowly close the bypass valve until the desired vacuum is reached. Do not reverse the direction of the bypass valve, as this will cause water to back up into the filter holder. If the desired vacuum is exceeded, either leak-check at this higher vacuum, or end the leak check and start over.

8.1.3.2.4 When the leak check is completed, first slowly remove the plug from the inlet to the probe, filter holder, and immediately turn off the vacuum pump. This prevents the water in the impingers from being forced backward into the filter holder and the silica gel from being entrained backward into the third impinger.

8.1.3.3 Leak Checks During Sample Run. If, during the sampling run, a component (*e.g.,* filter assembly or impinger) change becomes necessary, a leak check shall be conducted immediately before the change is made. The leak check shall be done according to the procedure outlined in section 8.1.3.2 above, except that it shall be done at a vacuum equal to or greater than the maximum value recorded up to that point in the test. If the leakage rate is found to be no greater than 0.00057 m^3/min (0.020 cfm) or 4 percent of the average sampling rate (whichever is less), the results are acceptable, and no correction will need to be applied to the total volume of dry gas metered; if, however, a higher leakage rate is obtained, either record the leakage rate and plan to correct the sample volume as shown in section 12.3 of Method 5, or void the sample run.

Note: Immediately after component changes, leak checks are optional. If such leak checks are done, the procedure outlined in section 8.1.3.2 above should be used.

8.1.3.4 Post-Test Leak Check. A leak check of the sampling train is mandatory at the conclusion of each sampling run. The leak check shall be performed in accordance with the procedures outlined in section 8.1.3.2, except that it shall be conducted at a vacuum equal to or greater than the maximum value reached during the sampling run. If the leakage rate is found to be no greater than 0.00057 m^3 min (0.020 cfm) or 4 percent of the average sampling rate (whichever is less), the results are acceptable, and no correction need be applied to the total volume of dry gas metered. If, however, a higher leakage rate is obtained, either record the leakage rate and correct the sample volume as shown in section 12.3 of Method 5 or void the sampling run.

* * * * *

8.1.4.2 At the end of the sample run, close the coarse adjust valve, remove the probe and nozzle from the stack, turn off the pump, record the final DGM meter reading, and conduct a post-test leak check, as outlined in section 8.1.3.4.

* * * * *

9.1 Miscellaneous Quality Control Measures.

Section	Quality control measure	Effect
Section 8.1.3.2.2	Leak rate of the sampling system cannot exceed four percent of the average sampling rate or 0.00057 m^3/min (0.020 cfm).	Ensures the accuracy of the volume of gas sampled. (Reference Method).
Section 8.2.1	Leak rate of the sampling system cannot exceed two percent of the average sampling rate.	Ensures the accuracy of the volume of gas sampled. (Approximation Method).

* * * * *

11.1 Reference Method. Weigh the impingers after sampling and record the difference in weight to the nearest 0.5 g at a minimum. Determine the increase in weight of the silica gel (or silica gel plus impinger) to the nearest 0.5 g at a minimum. Record this information (see example data sheet, Figure 4–5), and calculate the moisture content, as described in section 12.0.

11.2 Approximation Method. Weigh the contents of the two impingers, and measure the weight to the nearest 0.5 g.

* * * * *

12.1.1 Nomenclature.

B_{ws} = Proportion of water vapor, by volume, in the gas stream.

M_w = Molecular weight of water, 18.015 g/g-mole (18.015 lb/lb-mole).

P_m = Absolute pressure (for this method, same as barometric pressure) at the dry gas meter, mm Hg (in. Hg).

P_{std} = Standard absolute pressure, 760 mm Hg (29.92 in. Hg).

R = Ideal gas constant, 0.06236 (mm Hg)(m^3)/(g-mole)(°K) for metric units and 21.85 (in. Hg)(ft^3)/(lb-mole) (°R) for English units.

T_m = Absolute temperature at meter, °K (°R).

T_{std} = Standard absolute temperature, 293.15 °K (527.67 °R).

V_f = Final weight of condenser water plus impinger, g.

V_i = Initial weight, if any, of condenser water plus impinger, g.

V_m = Dry gas volume measured by dry gas meter, dcm (dcf).

$V_{m(std)}$ = Dry gas volume measured by the dry gas meter, corrected to standard conditions, dscm (dscf).

$V_{wc(std)}$ = Volume of water vapor condensed, corrected to standard conditions, scm (scf).

$V_{wsg(std)}$ = Volume of water vapor collected in silica gel, corrected to standard conditions, scm (scf).

W_f = Final weight of silica gel or silica gel plus impinger, g.

W_i = Initial weight of silica gel or silica gel plus impinger, g.

Y = Dry gas meter calibration factor.

ΔV_m = Incremental dry gas volume measured by dry gas meter at each traverse point, dcm (dcf).

12.1.2 Volume of Water Vapor Condensed.

$$V_{wc(std)} = \frac{(Vf - Vi)RT_{std}}{P_{std}M_w} \quad Eq\ 4-1$$

$$= K_1(Vf - Vi)$$

Where:

K_1 = 0.001335 m^3/g for metric units,
= 0.04716 ft^3/g for English units.

12.1.3 * * *

K_3 = 0.001335 m^3/g for metric units,
= 0.04716 ft^3/g for English units.

* * * * *

12.2.1 Nomenclature.

B_{wm} = Approximate proportion by volume of water vapor in the gas stream leaving the second impinger, 0.025.

B_{ws} = Water vapor in the gas stream, proportion by volume.

M_w = Molecular weight of water, 18.015 g/g-mole (18.015 lb/lb-mole).

P_m = Absolute pressure (for this method, same as barometric pressure) at the dry gas meter, mm Hg (in. Hg).

P_{std} = Standard absolute pressure, 760 mm Hg (29.92 in. Hg).

R = Ideal gas constant, 0.06236 [(mm Hg)(m^3)]/[(g-mole)(K)] for metric units and 21.85 [(in. Hg)(ft^3)]/[(lb-mole)(°R)] for English units.

T_m = Absolute temperature at meter, °K (°R).

T_{std} = Standard absolute temperature, 293.15 °K (527.67 °R).

V_f = Final weight of condenser water plus impinger, g.

V_i = Initial weight, if any, of condenser water plus impinger, g.

V_m = Dry gas volume measured by dry gas meter, dcm (dcf).

$V_{m(std)}$ = Dry gas volume measured by dry gas meter, corrected to standard conditions, dscm (dscf).

$V_{wc(std)}$ = Volume of water vapor condensed, corrected to standard conditions, scm (scf).

Y = Dry gas meter calibration factor.

12.2.2 Volume of Water Vapor Collected.

$$V_{wc(std)} = \frac{(Vf - Vi)RT_{std}}{P_{std}M_w} \quad Eq\ 4-5$$

$$= K_5(Vf - Vi)$$

K_5 = 0.001335 m^3/g for metric units,
= 0.04716 ft^3/g for English units.

* * * * *

BILLING CODE 6560–50–P

Clock Time	Gas Volume through meter (Vm), (m^3 or ft^3)	Rate meter setting (m^3/min or ft^3/min)	Meter temperature (°C or °F)

Figure 4-4. Example Moisture Determination Field Data Sheet – Approximation Method

	Impinger weight (g)	Silica gel weight (g)
Final		
Initial		
Difference		

Figure 4-5. Analytical Data – Reference Method

BILLING CODE 6560–50–C

Method 5—Determination of Particulate Matter Emissions From Stationary Sources

* * * * *

6.1.1.8 Condenser. The following system shall be used to determine the stack gas moisture content: Four impingers connected in series with leak-free ground glass fittings or any similar leak-free noncontaminating fittings. The first, third, and fourth impingers shall be of the Greenburg-Smith design, modified by replacing the tip with a 1.3 cm (½ in.) ID glass tube extending to about 1.3 cm (½ in.) from the bottom of the flask. The second impinger shall be of the Greenburg-Smith design with the standard tip. Modifications (*e.g.,* using flexible connections between the impingers, using materials other than glass, or using flexible vacuum lines to connect the filter holder to the condenser) may be used, subject to the approval of the Administrator. The first and second impingers shall contain known quantities of water (Section 8.3.1), the third shall be empty, and the fourth shall contain a known weight of silica gel, or equivalent desiccant. A temperature sensor, capable of measuring temperature to within 1 °C (2 °F) shall be placed at the outlet of the fourth impinger for monitoring purposes. Alternatively, any system that cools the sample gas stream and allows measurement of the water condensed and moisture leaving the condenser, each to within 0.5 g may be used, subject to the approval of the Administrator. An acceptable technique involves the measurement of condensed water either gravimetrically and the determination of the moisture leaving the condenser by: (1) Monitoring the temperature and pressure at the exit of the condenser and using Dalton's law of partial pressures; or (2) passing the sample gas stream through a tared silica gel (or equivalent desiccant) trap with exit gases kept below 20 °C (68 °F) and determining the weight gain. If means other than silica gel are used to determine the amount of moisture leaving the condenser, it is recommended that silica gel (or equivalent) still be used between the condenser system and pump to prevent moisture condensation in the pump and metering devices and to avoid the need to make corrections for moisture in the metered volume.

Note: If a determination of the PM collected in the impingers is desired in addition to moisture content, the impinger system described above shall be used, without modification. Individual States or control agencies requiring this information shall be contacted as to the sample recovery and analysis of the impinger contents.

* * * * *

6.2.4 Petri dishes. For filter samples; glass, polystyrene, or polyethylene, unless otherwise specified by the Administrator.

6.2.5 Balance. To measure condensed water to within 0.5 g at a minimum.

* * * * *

8.1.2 Check filters visually against light for irregularities, flaws, or pinhole leaks. Label filters of the proper diameter on the back side near the edge using numbering machine ink. As an alternative, label the shipping containers (glass, polystyrene or polyethylene petri dishes), and keep each filter in its identified container at all times except during sampling.

* * * * *

8.7.6.4 Impinger Water. Treat the impingers as follows: Make a notation of any color or film in the liquid catch. Measure the liquid that is in the first three impingers by weighing it to within 0.5 g at a minimum by using a balance. Record the weight of liquid present. This information is required to calculate the moisture content of the effluent gas. Discard the liquid after measuring and recording the weight, unless analysis of the impinger catch is required (see *Note*, section 6.1.1.8). If a different type of condenser is used, measure the amount of moisture condensed gravimetrically.

* * * * *

12.1 Nomenclature.

A_n = Cross-sectional area of nozzle, m² (ft²).

B_{ws} = Water vapor in the gas stream, proportion by volume.

C_a = Acetone blank residue concentration, mg/mg.

c_s = Concentration of particulate matter in stack gas, dry basis, corrected to standard conditions, g/dscm (gr/dscf).

I = Percent of isokinetic sampling.

L_1 = Individual leakage rate observed during the leak-check conducted prior to the first component change, m³/min (ft³/min)

L_a = Maximum acceptable leakage rate for either a pretest leak-check or for a leak-check following a component change; equal to 0.00057 m³/min (0.020 cfm) or 4 percent of the average sampling rate, whichever is less.

L_i = Individual leakage rate observed during the leak-check conducted prior to the "i^{th}" component change (i = 1, 2, 3 . . . n), m³/min (cfm).

L_p = Leakage rate observed during the post-test leak-check, m³/min (cfm).

m_a = Mass of residue of acetone after evaporation, mg.

m_n = Total amount of particulate matter collected, mg.

M_w = Molecular weight of water, 18.015 g/g-mole (18.015 lb/lb-mole).

P_{bar} = Barometric pressure at the sampling site, mm Hg (in. Hg).

P_s = Absolute stack gas pressure, mm Hg (in. Hg).

P_{std} = Standard absolute pressure, 760 mm Hg (29.92 in. Hg).

R = Ideal gas constant, 0.06236 ((mm Hg)(m³))/((K)(g-mole)) {21.85 ((in. Hg) (ft³))/((°R) (lb-mole))}.

T_m = Absolute average DGM temperature (see Figure 5–3), K (°R).

T_s = Absolute average stack gas temperature (see Figure 5–3), K (°R).

T_{std} = Standard absolute temperature, 293.15 K (527.67 °R).

V_a = Volume of acetone blank, ml.

V_{aw} = Volume of acetone used in wash, ml.

V_{lc} = Total volume of liquid collected in impingers and silica gel (see Figure 5–6), g.

V_m = Volume of gas sample as measured by dry gas meter, dcm (dcf).

$V_{m(std)}$ = Volume of gas sample measured by the dry gas meter, corrected to standard conditions, dscm (dscf).

$V_{w(std)}$ = Volume of water vapor in the gas sample, corrected to standard conditions, scm (scf).

V_s = Stack gas velocity, calculated by Method 2, Equation 2–7, using data obtained from Method 5, m/sec (ft/sec).

W_a = Weight of residue in acetone wash, mg.

Y = Dry gas meter calibration factor.

ΔH = Average pressure differential across the orifice meter (see Figure 5–4), mm H_2O (in. H_2O).

ρ_a = Density of acetone, mg/ml (see label on bottle).

θ = Total sampling time, min.

θ_1 = Sampling time interval, from the beginning of a run until the first component change, min.

θ_i = Sampling time interval, between two successive component changes, beginning with the interval between the first and second changes, min.

θ_p = Sampling time interval, from the final (n^{th}) component change until the end of the sampling run, min.

13.6 = Specific gravity of mercury.

60 = Sec/min.

100 = Conversion to percent.

* * * * *

12.3 * * *

K_1 = 0.38572 °K/mm Hg for metric units, = 17.636 °R/in. Hg for English units.

* * * * *

12.4 Volume of Water Vapor Condensed

$$V_{w(std)} = V_{lc}\frac{RT_{std}}{M_w P_{std}} = K_2 V_{lc} \qquad \text{Eq. 5-2}$$

Where:

K_2 = 0.001335 m³/g for metric units, = 0.04716 ft³/g for English units.

* * * * *

12.11.1 * * *

Where:

K_4 = 0.003456 ((mm Hg)(m³))/((ml)(°K)) for metric units,
= 0.002668 ((in. Hg)(ft³))/((ml)(°R)) for English units.

* * * * *

12.11.2 * * *

Where:

K_5 = 4.3209 for metric units, = 0.09450 for English units.

* * * * *

16.1.1.4 * * *

Where:

K_1 = 0.38572 °K/mm Hg for metric units, = 17.636 °R/in. Hg for English units.

T_{adj} = 273.15 °C for metric units = 459.67 °F for English units.

* * * * *

16.2.3.3 * * *

Where:

K_1 = 0.38572 °K/mm Hg for metric units, = 17.636 °R/in. Hg for English units.

* * * * *

18.0 * * *

Plant ______
Date
Run No.
Filter No.

Amount liquid lost during transport, mg
Acetone blank volume, ml

Acetone blank concentration, mg/mg (Equation 5–4)

Acetone wash blank, mg (Equation 5–5)

Container number	Weight of particulate collected, mg		
	Final weight	Tare weight	Weight gain
1.			
2.			
Total collected particulate			
Less acetone wash blank			
Weight of particulate matter			
	Weight of liquid collected, g		
	Impinger weight	Silica gel weight	
Final			
Initial			
Liquid collected			
Total weight collected			

Figure 5-6. Analytical Data Sheet

* * * * *

■ 22. Amend Appendix A–4 to part 60 in Method 7C by revising section 7.2.11 and in Method 7E by revising section 8.5 introductory text to read as follows:

Appendix A–4 to Part 60—Test Methods 6 Through 10B

* * * * *

Method 7C—Determination of Nitrogen Oxide Emissions From Stationary Sources—Alkaline—Permanganate/Colorimetric Method

* * * * *

7.2.11 Sodium Nitrite ($NaNO_2$) Standard Solution, Nominal Concentration, 1000 µg NO_2-/ml. Desiccate $NaNO_2$ overnight. Accurately weigh 1.4 to 1.6 g of $NaNO_2$ (assay of 97 percent $NaNO_2$ or greater), dissolve in water, and dilute to 1 liter. Calculate the exact NO_2-concentration using Equation 7C–1 in section 12.2. This solution is stable for at least 6 months under laboratory conditions.

* * * * *

Method 7E—Determination of Nitrogen Oxide Emissions From Stationary Sources (Instrumental Analyzer Procedure)

* * * * *

8.5 *Post-Run System Bias Check and Drift Assessment.*

How do I confirm that each sample I collect is valid? After each run, repeat the system bias check or 2-point system calibration error check (for dilution systems) to validate the run. Do not make adjustments to the measurement system (other than to maintain the target sampling rate or dilution ratio) between the end of the run and the completion of the post-run system bias or system calibration error check. Note that for all post-run system bias or 2-point system calibration error checks, you may inject the low-level gas first and the upscale gas last, or vice-versa. If conducting a relative accuracy test or relative accuracy test audit, consisting of nine runs or more, you may risk sampling for up to three runs before performing the post-run bias or system calibration error check provided you pass this test at the conclusion of the group of three runs. A failed post-run bias or system calibration error check in this case will invalidate all runs subsequent to the last passed check. When conducting a performance or compliance test, you must perform a post-run system bias or system calibration error check after each individual test run.

* * * * *

■ 23. Amend Appendix A–5 to part 60, Method 12 by:

■ a. Revising sections ‘‘7.1.2’’, ‘‘8.7.1.6’’, ‘‘8.7.3.1’’, ‘‘8.7.3.3’’, ‘‘8.7.3.6’’, ‘‘12.1’’, ‘‘12.3’’, ‘‘16.1’’ through ‘‘16.5’’;

■ b. Adding sections 16.5.1 and 16.5.2; and

■ c. Removing section 16.6.

The revisions and additions read as follows:

Appendix A–5 to Part 60—Test Methods 11 Through 15A

* * * * *

Method 12—Determination of Inorganic Lead Emissions From Stationary Sources

* * * * *

7.1.2 Silica Gel and Crushed Ice. Same as Method 5, sections 7.1.2 and 7.1.4, respectively.

* * * * *

8.7.1.6 Brush and rinse with 0.1 N HNO_3 the inside of the front half of the filter holder. Brush and rinse each surface three times or more, if needed, to remove visible sample matter. Make a final rinse of the brush and filter holder. After all 0.1 N HNO_3 washings and sample matter are collected in the sample container, tighten the lid on the sample container so that the fluid will not leak out when it is shipped to the laboratory. Mark the height of the fluid level to determine whether leakage occurs during transport. Label the container to identify its contents clearly.

* * * * *

8.7.3.1 Cap the impinger ball joints.

* * * * *

8.7.3.3 Treat the impingers as follows: Make a notation of any color or film in the liquid catch. Measure the liquid that is in the first three impingers by weighing it to within 0.5 g at a minimum by using a balance. Record the weight of liquid present. The liquid weight is needed, along with the silica gel data, to calculate the stack gas moisture content (see Method 5, Figure 5–6).

* * * * *

8.7.3.6 Rinse the insides of each piece of connecting glassware for the impingers twice with 0.1 N HNO_3; transfer this rinse into Container No. 4. Do not rinse or brush the glass-fritted filter support. Mark the height of the fluid level to determine whether leakage occurs during transport. Label the container to identify its contents clearly.

* * * * *

12.1 Nomenclature.

A_m = Absorbance of the sample solution.

A_n = Cross-sectional area of nozzle, m^2 (ft^2).

A_t = Absorbance of the spiked sample solution.

B_{ws} = Water in the gas stream, proportion by volume.

C_a = Lead concentration in standard solution, µg/ml.

C_m = Lead concentration in sample solution analyzed during check for matrix effects, µg/ml.

C_s = Lead concentration in stack gas, dry basis, converted to standard conditions, mg/dscm (gr/dscf).

I = Percent of isokinetic sampling.

L_1 = Individual leakage rate observed during the leak-check conducted prior to the first component change, m^3/min (ft^3/min).

L_a = Maximum acceptable leakage rate for either a pretest leak-check or for a leak-check following a component change; equal to 0.00057 m^3/min (0.020 cfm) or 4 percent of the average sampling rate, whichever is less.

L_i = Individual leakage rate observed during the leak-check conducted prior to the ''ith'' component change (i = 1, 2, 3 * * * n), m^3/min (cfm).

L_p = Leakage rate observed during the post-test leak-check, m^3/min (cfm).

m_t = Total weight of lead collected in the sample, μg.

M_w = Molecular weight of water, 18.0 g/g-mole (18.0 lb/lb-mole).

P_{bar} = Barometric pressure at the sampling site, mm Hg (in. Hg).

P_s = Absolute stack gas pressure, mm Hg (in. Hg).

P_{std} = Standard absolute pressure, 760 mm Hg (29.92 in. Hg).

R = Ideal gas constant, 0.06236 [(mm Hg) (m^3)]/[(°K) (g-mole)] {21.85 [(in. Hg) (ft^3)]/[(°R) (lb-mole)]}.

T_m = Absolute average dry gas meter temperature (see Figure 5–3 of Method 5), °K (°R).

T_{std} = Standard absolute temperature, 293 °K (528 °R).

v_s = Stack gas velocity, m/sec (ft/sec).

V_m = Volume of gas sample as measured by the dry gas meter, dry basis, m^3 (ft^3).

$V_{m(std)}$ = Volume of gas sample as measured by the dry gas meter, corrected to standard conditions, m^3 (ft^3).

$V_{w(std)}$ = Volume of water vapor collected in the sampling train, corrected to standard conditions, m^3 (ft^3).

Y = Dry gas meter calibration factor.

ΔH = Average pressure differential across the orifice meter (see Figure 5–3 of Method 5), mm H_2O (in. H_2O).

θ = Total sampling time, min.

θ_1 = Sampling time interval, from the beginning of a run until the first component change, min.

θ_i = Sampling time interval, between two successive component changes, beginning with the interval between the first and second changes, min.

θ_p = Sampling time interval, from the final (n^{th}) component change until the end of the sampling run, min.

* * * * *

12.3 Dry Gas Volume, Volume of Water Vapor Condensed, and Moisture Content. Using data obtained in this test, calculate $V_{m(std)}$, $V_{w(std)}$, and B_{ws} according to the procedures outlined in Method 5, sections 12.3 through 12.5.

* * * * *

16.1 Simultaneous Determination of Particulate Matter and Lead Emissions. Method 12 may be used to simultaneously determine Pb and particulate matter provided:

(1) A glass fiber filter with a low Pb background is used and this filter is checked, desiccated and weighed per section 8.1 of Method 5,

(2) An acetone rinse, as specified by Method 5, sections 7.2 and 8.7.6.2, is used to remove particulate matter from the probe and inside of the filter holder prior to and kept separate from the 0.1 N HNO_3 rinse of the same components,

(3) The recovered filter, the acetone rinse, and an acetone blank (Method 5, section 7.2) are subjected to the gravimetric analysis of Method 5, sections 6.3 and 11.0 prior to the analysis for Pb as described below, and

(4) The entire train contents, including the 0.1 N HNO_3 impingers, filter, acetone and 0.1 N HNO_3 probe rinses are treated and analyzed for Pb as described in sections 8.0 and 11.0 of this method.

16.2 Filter Location. A filter may be used between the third and fourth impingers provided the filter is included in the analysis for Pb.

16.3 In-Stack Filter. An in-stack filter may be used provided: (1) A glass-lined probe and at least two impingers, each containing 100 ml of 0.1 N HNO_3 after the in-stack filter, are used and (2) the probe and impinger contents are recovered and analyzed for Pb. Recover sample from the nozzle with acetone if a particulate analysis is to be made as described in section 16.1 of this method.

16.4 Inductively Coupled Plasma-Atomic Emission Spectrometry (ICP–AES) Analysis. ICP–AES may be used as an alternative to atomic absorption analysis provided the following conditions are met:

16.4.1 Sample collection/recovery, sample loss check, and sample preparation procedures are as defined in sections 8.0, 11.1, and 11.2, respectively, of this method.

16.4.2 Analysis shall be conducted following Method 6010D of SW–846 (incorporated by reference, see § 60.17). The limit of detection for the ICP–AES must be demonstrated according to section 15.0 of Method 301 in appendix A of part 63 of this chapter and must be no greater than one-third of the applicable emission limit. Perform a check for matrix effects according to section 11.5 of this method.

16.5 Inductively Coupled Plasma-Mass Spectrometry (ICP–MS) Analysis. ICP–MS may be used as an alternative to atomic absorption analysis provided the following conditions are met:

16.5.1 Sample collection/recovery, sample loss check, and sample preparation procedures are as defined in sections 8.0, 11.1, and 11.2, respectively of this method.

16.5.2 Analysis shall be conducted following Method 6020B of SW–846 (incorporated by reference, see § 60.17). The limit of detection for the ICP–MS must be demonstrated according to section 15.0 of Method 301 in appendix A to part 63 of this chapter and must be no greater than one-third of the applicable emission limit. Use the multipoint calibration curve option in section 10.4 of Method 6020B and perform a check for matrix effects according to section 11.5 of this method.

* * * * *

■ 24. Amend Appendix A–6 to part 60 by:

■ a. In Method 16B by:

■ i. Revising sections 2.1, 6.1, 8.2;

■ ii. Removing section 8.3;

■ iii. Redesignating sections 8.4, 8.4.1, and 8.4.2 as 8.3, 8.3.1, and 8.3.2, respectively;

■ iv. Revising section 11.1; and

■ v. Adding section 11.2; and

■ b. In Method 16C, revising section 13.1.

The revisions and addition read as follows:

Appendix A–6 to Part 60—Test Methods 16 Through 18

* * * * *

Method 16B—Determination of Total Reduced Sulfur Emissions From Stationary Sources

* * * * *

2.1 A gas sample is extracted from the stack. The SO_2 is removed selectively from the sample using a citrate buffer solution. The TRS compounds are then thermally oxidized to SO_2 and analyzed as SO_2 by gas chromatography (GC) using flame photometric detection (FPD).

* * * * *

6.1 Sample Collection. The sampling train is shown in Figure 16B–1. Modifications to the apparatus are accepted provided the system performance check in section 8.3.1 is met.

* * * * *

8.2 Sample Collection. Before any source sampling is performed, conduct a system performance check as detailed in section 8.3.1 to validate the sampling train components and procedures. Although this test is optional, it would significantly reduce the possibility of rejecting tests as a result of failing the post-test performance check. At the completion of the pretest system performance check, insert the sampling probe into the test port making certain that no dilution air enters the stack though the port. Condition the entire system with sample for a minimum of 15 minutes before beginning analysis. If the sample is diluted, determine the dilution factor as in section 10.4 of Method 15.

* * * * *

11.1 Analysis. Inject aliquots of the sample into the GC/FPD analyzer for analysis. Determine the concentration of SO_2 directly from the calibration curves or from the equation for the least-squares line.

11.2 Perform analysis of a minimum of three aliquots or one every 15 minutes, whichever is greater, spaced evenly over the test period.

* * * * *

Method 16C—Determination of Total Reduced Sulfur Emissions From Stationary Sources

* * * * *

13.1 Analyzer Calibration Error. At each calibration gas level (low, mid, and high), the calibration error must either not exceed 5.0 percent of the calibration span or $|C_{Dir} - C_v|$ must be ≤0.5 ppmv.

* * * * *

■ 25. Amend Appendix A–7 to part 6 by:

■ a. In Method 24, revising section 6.2.

■ b. In Method 25C, revising sections 8.4.2, 9.1, 12.5, 12.5.1, and 12.5.2.

The revisions read as follows:

Appendix A–7 to Part 60—Test Methods 19 Through 25E

* * * * *

Method 24—Determinaton of Volatile Matter Content, Water Content, Density, Volume Solids, and Weight Solids of Surface Coatings

* * * * *

6.2 ASTM D 2369–81, 87, 90, 92, 93, 95, or 10. Standard Test Method for Volatile Content of Coatings.

* * * * *

Method 25C—Determination of Nonmethane Organic Compounds (NMOC) in Landfill Gases

* * * * *

8.4.2 Use Method 3C to determine the percent N_2 and O_2 in each cylinder. The presence of N_2 and O_2 indicate either infiltration of ambient air into the landfill gas sample or an inappropriate testing site has been chosen where anaerobic decomposition has not begun. The landfill gas sample is acceptable if the concentration of N_2 is less than 20 percent. Alternatively, the oxygen content of each cylinder must be less than 5 percent. Landfills with 3-year average annual rainfalls equal to or less than 20 inches annual rainfalls samples are acceptable when the N_2 to O_2 concentration ratio is greater than 3.71.

* * * * *

9.1 Miscellaneous Quality Control Measures.

Section	Quality control measure	Effect
8.4.2	If the 3-year average annual rainfall is greater than 20 inches, verify that landfill gas sample contains less than 20 percent N_2 and 5 percent O_2. Landfills with 3-year average annual rainfalls equal to or less than 20 inches annual rainfalls samples are acceptable when the N_2 to O_2 concentration ratio is greater than 3.71.	Ensures that ambient air was not drawn into the landfill gas sample and gas was sampled from an appropriate location. If outside of range, invalidate sample and repeat sample collection.
10.1, 10.2	NMOC analyzer initial and daily performance checks	Ensures precision of analytical results.

* * * * *

12.5 You must correct the NMOC Concentration for the concentration of nitrogen or oxygen based on which gas or gases passes the requirements in section 9.1 or based on the 3-year average annual rainfall based on the closest NOAA land-based station.

12.5.1 NMOC Concentration with nitrogen correction. Use Equation 25C–4 to calculate the concentration of NMOC for each sample tank when the nitrogen concentration is less than 20 percent.

$$C_t = \frac{\frac{P_{tf}}{T_{tf}}}{\left(\frac{P_t}{T_t}-\frac{P_{ti}}{T_{ti}}\right)\left(1-\frac{99}{78}C_{N2}\right)-B_w}\frac{1}{r}\sum_{j=1}^{r} C_{tm^{(j)}} \quad \text{Eq.25C-4}$$

12.5.2 NMOC Concentration with oxygen correction. Use Equation 25C–5 to calculate the concentration of NMOC for each sample tank if the landfill gas oxygen is less than 5 percent and the landfill gas nitrogen concentration is greater than 20 percent, or 3-year average annual rainfall based annual rainfall of less than 20 inches.

$$C_t = \frac{\frac{P_{tf}}{T_{tf}}}{\left(\frac{P_t}{T_t}-\frac{P_{ti}}{T_{ti}}\right)\left(1-\frac{99}{21}C_{Ox}\right)-B_w}\frac{1}{r}\sum_{j=1}^{r} C_{tm^{(j)}} \quad \text{Eq.25C-5}$$

* * * * *

■ 26. Amend Appendix A–8 to part 60 by:

■ a. In Method 26, revising section 8.1.2; and

■ b. In Method 26A, revising sections 6.1.3 and 8.1.5.

The revisions read as follows:

Appendix A–8 to Part 60—Test Methods 26 Through 30B

* * * * *

Method 26—Determination of Hydrogen Halide and Halogen Emissions From Stationary Sources Non-Isokinetic Method

* * * * *

8.1.2 Adjust the probe temperature and the temperature of the filter and the stopcock (*i.e.,* the heated area in Figure 26–1) to a temperature sufficient to prevent water condensation. This temperature must be maintained between 120 and 134 °C (248 and 273 °F). The temperature should be monitored throughout a sampling run to ensure that the desired temperature is maintained. It is important to maintain a temperature around the probe and filter in this range since it is extremely difficult to purge acid gases off these components. (These components are not quantitatively recovered and, hence, any collection of acid gases on these components would result in potential under reporting of these emissions. The applicable subparts may specify alternative higher temperatures.)

* * * * *

Method 26A—Determination of Hydrogen Halide and Halogen Emissions From Stationary Sources—Isokinetic Method

* * * * *

6.1.3 Pitot Tube, Differential Pressure Gauge, Filter Heating System, Filter Temperature Sensor with a glass or Teflon encasement, Metering System, Barometer, Gas Density Determination Equipment. Same as Method 5, sections 6.1.1.3, 6.1.1.4, 6.1.1.6, 6.1.1.7, 6.1.1.9, 6.1.2, and 6.1.3.

* * * * *

8.1.5 Sampling Train Operation. Follow the general procedure given in Method 5, Section 8.5. It is important to maintain a temperature around the probe, filter (and cyclone, if used) between 120 and 134 °C (248 and 273 °F) since it is extremely difficult to purge acid gases off these components. (These components are not quantitatively recovered and hence any collection of acid gases on these components would result in potential under reporting these emissions. The applicable subparts may specify alternative higher temperatures.) For each run, record the data required on a data sheet such as the one shown in Method 5, Figure 5–3. If the condensate impinger becomes too full, it may be emptied, recharged with 50 ml of 0.1 N H2SO4, and replaced during the sample run. The condensate emptied must be saved and included in the measurement of the volume of moisture collected and included in the sample for analysis. The additional 50 ml of absorbing reagent must also be considered in calculating the moisture. Before the sampling train integrity is compromised by removing the impinger, conduct a leak-check as described in Method 5, section 8.4.2.

* * * * *

■ 27. Amend Appendix B to part 60 by:
■ a. In Performance Specification 4B, revising section 4.5;
■ b. In Performance Specification 5, revising sections 5.0 and 8.1;
■ c. In Performance Specification 6, revising sections 13.1 and 13.2;
■ d. In Performance Specification 8, redesignating sections 8.3, 8.4, and 8.5 as 8.4, 8.5, and 8.6, respectively;
■ e. Adding new section 8.3;
■ f. In Performance Specification 9, revising sections 7.2, 8.3, 8.4, 10.1, 10.2, 13.1, and 13.2;
■ g. Adding section 13.4;
■ h. In Performance Specification 18, revising sections 2.3 and 11.9.1.

The revisions and additions read as follows:

Appendix B to Part 60—Performance Specifications

* * * * *

Performance Specification 4B—Specifications and Test Procedures for Carbon Monoxide and Oxygen Continuous Monitoring Systems in Stationary Sources

* * * * *

4.5 *Response Time.* The response time for the CO or O_2 monitor must not exceed 240 seconds.

* * * * *

Performance Specification 5—Specifications and Test Procedures for TRS Continuous Emission Monitoring Systems in Stationary Sources

* * * * *

5.0 Safety

This performance specification may involve hazardous materials, operations, and equipment. This performance specification may not address all of the safety problems associated with its use. It is the responsibility of the user to establish appropriate safety and health practices and determine the applicable regulatory limitations prior to performing this performance specification. The CEMS user's manual should be consulted for specific precautions to be taken with regard to the analytical procedures.

* * * * *

8.1 Relative Accuracy Test Procedure. Sampling Strategy for reference method (RM) Tests, Number of RM Tests, and Correlation of RM and CEMS Data are the same as PS 2, sections 8.4.3, 8.4.4, and 8.4.5, respectively.

Note: For Method 16, a sample is made up of at least three separate injects equally spaced over time. For Method 16A, a sample is collected for at least 1 hour. For Method 16B, you must analyze a minimum of three aliquots spaced evenly over the test period.

* * * * *

Performance Specification 6—Specifications and Test Procedures for Continuous Emission Rate Monitoring Systems in Stationary Sources

* * * * *

13.1 Calibration Drift. Since the CERMS includes analyzers for several measurements, the CD shall be determined separately for each analyzer in terms of its specific measurement. The calibration for each analyzer associated with the measurement of flow rate shall not drift or deviate from each reference value of flow rate by more than 3 percent of the respective high-level reference value over the CD test period (*e.g.,* seven-day) associated with the pollutant analyzer. The CD specification for each analyzer for which other PSs have been established (*e.g.,* PS 2 for SO_2 and NO_X), shall be the same as in the applicable PS.

13.2 CERMS Relative Accuracy. Calculate the CERMS Relative Accuracy using Eq. 2–6 of section 12 of Performance Specification 2. The RA of the CERMS shall be no greater than 20 percent of the mean value of the RM's test data in terms of the units of the emission standard, or in cases where the average emissions for the test are less than 50 percent of the applicable standard, substitute the emission standard value in the denominator of Eq. 2–6 in place of the RM.

* * * * *

Performance Specification 8—Performance Specifications for Volatile Organic Compound Continuous Emission Monitoring Systems in Stationary Sources

* * * * *

8.3 Calibration Drift Test Procedure. Same as section 8.3 of PS 2.

8.4 Reference Method (RM). Use the method specified in the applicable regulation or permit, or any approved alternative, as the RM.

8.5 Sampling Strategy for RM Tests, Correlation of RM and CEMS Data, and Number of RM Tests. Follow PS 2, sections 8.4.3, 8.4.5, and 8.4.4, respectively.

8.6 Reporting. Same as section 8.5 of PS 2.

* * * * *

Performance Specification 9—Specifications and Test Procedures for Gas Chromatographic Continuous Emission Monitoring Systems in Stationary Sources

* * * * *

7.2 Performance Audit Gas. Performance Audit Gas is an independent cylinder gas or cylinder gas mixture. A certified EPA audit gas shall be used, when possible. A gas mixture containing all the target compounds within the calibration range and certified by EPA's Traceability Protocol for Assay and Certification of Gaseous Calibration Standards may be used when EPA performance audit materials are not available. If a certified EPA audit gas or a traceability protocol gas is not available, use a gas manufacturer standard accurate to 2 percent.

* * * * *

8.3 Seven (7)-Day Calibration Error (CE) Test Period. At the beginning of each 24-hour period, set the initial instrument set points by conducting a multi-point calibration for each compound. The multi-point calibration shall meet the requirements in sections 13.1, 13.2, and 13.3. Throughout the 24-hour period, sample and analyze the stack gas at the sampling intervals prescribed in the regulation or permit. At the end of the 24-hour period, inject the calibration gases at three concentrations for each compound in triplicate and determine the average instrument response. Determine the CE for each pollutant at each concentration using Equation 9–2. Each CE shall be ≤10 percent. Repeat this procedure six more times for a total of 7 consecutive days.

8.4 Performance Audit Test Periods. Conduct the performance audit once during the initial 7-day CE test and quarterly thereafter. Performance Audit Tests must be conducted through the entire sampling and analyzer system. Sample and analyze the EPA audit gas(es) (or the gas mixture) three times. Calculate the average instrument response. Results from the performance audit test must meet the requirements in sections 13.3 and 13.4.

* * * * *

10.1 Multi-Point Calibration. After initial startup of the GC, after routine maintenance or repair, or at least once per month, conduct a multi-point calibration of the GC for each target analyte. Calibration is performed at the instrument independent of the sample transport system. The multi-point calibration for each analyte shall meet the requirements in sections 13.1, 13.2, and 13.3.

* * * * *

10.2 Daily Calibration. Once every 24 hours, analyze the mid-level calibration standard for each analyte in triplicate. Calibration is performed at the instrument independent of the sample transport system. Calculate the average instrument response for each analyte. The average instrument response shall not vary by more than 10 percent from the certified concentration value of the cylinder for each analyte. If the difference between the analyzer response and the cylinder concentration for any target compound is greater than 10 percent, immediately inspect the instrument making any necessary adjustments, and conduct an initial multi-point calibration as described in section 10.1.

* * * * *

13.1 Calibration Error (CE). The CEMS must allow the determination of CE at all three calibration levels. The average CEMS calibration response must not differ by more than 10 percent of calibration gas value at each level after each 24-hour period and after any triplicate calibration response check.

13.2 Calibration Precision and Linearity. For each triplicate injection at each concentration level for each target analyte, any one injection shall not deviate more than 5 percent from the average concentration measured at that level. When the CEMS response is evaluated over three concentration levels, the linear regression curve for each organic compound shall be determined using Equation 9–1 and must have an r^2 ≥0.995.

* * * * *

13.4 Performance Audit Test Error. Determine the error for each average pollutant measurement using the Equation 9–2 in section 12.3. Each error shall be less than or equal to 10 percent of the cylinder gas certified value. Report the audit results including the average measured concentration, the error and the certified cylinder concentration of each pollutant as part of the reporting requirements in the appropriate regulation or permit.

* * * * *

Performance Specification 18—Performance Specifications and Test Procedures for Gaseous Hydrogen Chloride (HCl) Continuous Emission Monitoring Systems at Stationary Sources

* * * * *

2.3 The relative accuracy (RA) must be established against a reference method (RM) (*e.g.,* Method 26A, Method 320, ASTM International (ASTM) D6348–12, including mandatory annexes, or Method 321 for Portland cement plants as specified by the applicable regulation or, if not specified, as appropriate for the source concentration and category). Method 26 may be approved as a RM by the Administrator on a case-by-case basis if not otherwise allowed or denied in an applicable regulation.

* * * * *

11.9.1 Unless otherwise specified in an applicable regulation, use Method 26A in 40 CFR part 60, appendix A–8, Method 320 in 40 CFR part 63, appendix A, or ASTM D6348–12 including all annexes, as applicable, as the RMs for HCl measurement. Obtain and analyze RM audit samples, if they are available, concurrently with RM test samples according to the same procedure specified for performance tests in the general provisions of the applicable part. If Method 26 is not specified in an applicable subpart of the regulations, you may request approval to use Method 26 in appendix A–8 to this part as the RM on a site-specific basis under §§ 63.7(f) or 60.8(b). Other RMs for moisture, O_2, etc., may be necessary. Conduct the RM tests in such a way that they will yield results representative of the emissions from the source and can be compared to the CEMS data.

* * * * *

■ 28. Amend Appendix F to part 60, in Procedure 1, by revising section 5.2.3(2) to read as follows:

Appendix F to Part 60—Quality Assurance Procedures

Procedure 1—Quality Assurance Requirements for Gas Continuous Emission Monitoring Systems Used for Compliance Determination

* * * * *

5.2.3 * * *

(2) For the CGA, ±15 percent of the average audit value or ±5 ppm, whichever is greater; for diluent monitors, ±15 percent of the average audit value.

* * * * *

PART 61—NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS

■ 29. The authority citation for part 61 continues to read as follows:

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

■ 30. Amend Appendix B to part 61 by:

■ a. Adding the entries Method 114—Test Methods for Measuring Radionuclide Emissions from Stationary Sources and Method 115—Monitoring for Radon-222 Emissions at the end of the index for appendix B to part 61.

■ b. In Method 107, revising section 12.3, equation 107–3.

The additions and revisions read as follows:

Appendix B to Part 61—Test Methods

* * * * *

Method 114—Test Methods for Measuring Radionuclide Emissions From Stationary Sources

Method 115—Monitoring for Radon-222 Emissions

* * * * *

Method 107—Determination of Vinyl Chloride Content of In-Process Wastewater Samples, and Vinyl Chloride Content of Polyvinyl Chloride Resin Slurry, Wet Cake, and Latex Samples

* * * * *

12.3 * * *

$$C_{rvc} = \frac{A_s P_a}{R_f T_1}\left[\frac{M_v V_g}{Rm} + K_p (TS) T_2 + K_w (1 - TS) T_2\right] \qquad Eq. 107-3$$

* * * * *

PART 63—NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES

■ 31. The authority citation for part 63 continues to read as follows:

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

■ 32. Amend § 63.2 by revising the definition of ‘‘Alternative test method’’ to read as follows:

§ 63.2 Definitions.

* * * * *

Alternative test method means any method of sampling and analyzing for an air pollutant that has been demonstrated to the Administrator's satisfaction, using Method 301 in appendix A of this part, to produce results adequate for the Administrator's determination that it may be used in place of a test method specified in this part.

* * * * *

Subpart LLL—National Emission Standards for Hazardous Air Pollutants from the Portland Cement Manufacturing Industry

■ 33. Amend § 63.1349, by revising paragraphs (b)(7)(viii)(A) and (B), (b)(8)(vi), and (b)(8)(vii)(B) and (C) to read as follows:

§ 63.1349 Performance testing requirements.

* * * * *

(b) * * *

(7) * * *

(viii) * * *

(A) Determine the THC CEMS average value in ppmvw, and the average of your corresponding three total organic HAP compliance test runs, using Equation 12.

$$\bar{x} = \frac{1}{n}\sum_{i=1}^{n} X_i, \bar{y} = \frac{1}{n}\sum_{i=1}^{n} Y_i \qquad \text{(Eq. 12)}$$

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[EPA–HQ–OAR–2018–0815; FRL 10018–97–OAR]

RIN 2060–AU39

Test Methods and Performance Specifications for Air Emission Sources; Correction

AGENCY: Environmental Protection Agency (EPA).

ACTION: Correcting amendments.

SUMMARY: The Environmental Protection Agency (EPA) is correcting a final rule that was published in the **Federal Register** on October 7, 2020, and was effective on December 7, 2020. The final rule corrected and updated regulations for source testing of emissions. This correction does not change any final action taken by the EPA on October 7, 2020; this action corrects the amendatory instructions for Methods 4 and 5.

DATES: The correction is effective on March 23, 2021.

ADDRESSES: The EPA has established a docket for this action under Docket ID No. EPA–HQ–OAR–2018–0815. All documents in the docket are listed at *http://www.regulations.gov.* Although listed in the index, some information is not publicly available, *e.g.,* confidential business information or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the internet and will be publicly available only in hard copy. Publicly available docket materials are available electronically through *http://www.regulations.gov.*

FOR FURTHER INFORMATION CONTACT: Mrs. Lula H. Melton, Office of Air Quality Planning and Standards, Air Quality Assessment Division (E143–02), Environmental Protection Agency, Research Triangle Park, NC 27711; telephone number: (919) 541–2910; fax number: (919) 541–0516; email address: *melton.lula@epa.gov.*

SUPPLEMENTARY INFORMATION: In the final rulemaking published in the **Federal Register** on October 7, 2020 (85 FR 63394), there were some inadvertent errors made to Methods 4 and 5 due to unclear or incorrect amendatory instruction. In this correction document, we are clarifying and correcting the amendatory instructions for ''Appendix A–3 to part 60'' to correct the inadvertent errors and incorporate the revisions from the final rulemaking.

In Method 4, we are revising sections 8.1.3.1, 8.1.3.2, and adding sections 8.1.3.2.1, 8.1.3.2.2, 8.1.3.2.3, 8.1.3.2.4, 8.1.3.3, and 8.1.3.4. We are also revising section 12.1.3.

In Method 5, we are revising sections 12.3, 12.11.1, 12.11.2, 16.1.1.4, and 16.2.3.3.

List of Subjects 40 CFR Part 60

Environmental protection, Air pollution control, Incorporation by reference, Performance specifications, Test methods and procedures.

Joseph Goffman,

Acting Assistant Administrator, Office of Air and Radiation.

Accordingly, 40 CFR part 60 is corrected 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. Amend appendix A–3 to part 60 by:

■ a. In Method 4 by:

■ i. Revising sections ''8.1.3.1'' and ''8.1.3.2'';

■ ii. Adding sections ''8.1.3.2.1'', ''8.1.3.2.2'', ''8.1.3.2.3'', ''8.1.3.2.4'', ''8.1.3.3'', and ''8.1.3.4''; and

■ iii. Revising section ''12.1.3''; and

■ b. In Method 5 by revising sections ''12.3'', ''12.11.1'', ''12.11.2'', ''16.1.1.4'', and ''16.2.3.3''.

The additions and revisions read as follows:

Appendix A–3 to Part 60—Test Methods 4 through 5I

* * * * *

Method 4—Determination of Moisture Content in Stack Gases

* * * * *

8.1.3.1 Leak Check of Metering System Shown in Figure 4–1. That portion of the sampling train from the pump to the orifice meter should be leak-checked prior to initial use and after each shipment. Leakage after the pump will result in less volume being recorded than is actually sampled. The following procedure is suggested (see Figure 5–2 of Method 5): Close the main valve on the meter box. Insert a one-hole rubber stopper with rubber tubing attached into the orifice exhaust pipe. Disconnect and vent the low side of the orifice manometer. Close off the low side orifice tap. Pressurize the system to 13 to 18 cm (5 to 7 in.) water column by blowing into the rubber tubing. Pinch off the tubing and observe the manometer for one minute. A loss of pressure on the manometer indicates a leak in the meter box; leaks, if present, must be corrected. 8.1.3.2 Pretest Leak Check. A pretest leak check of the sampling train is recommended, but not required. If the pretest leak check is conducted, the following procedure should be used. 8.1.3.2.1 After the sampling train has been assembled, turn on and set the filter and probe heating systems to the desired operating temperatures. Allow time for the temperatures to stabilize. 8.1.3.2.2 Leak-check the train by first plugging the inlet to the filter holder and pulling a 380 mm (15 in.) Hg vacuum. Then connect the probe to the train, and leak-check at approximately 25 mm (1 in.) Hg vacuum; alternatively, the probe may be leak-checked with the rest of the sampling train, in one step, at 380 mm (15 in.) Hg vacuum. Leakage rates in excess of 4 percent of the average sampling rate or 0.00057 m^3/min (0.020 cfm), whichever is less, are unacceptable. 8.1.3.2.3 Start the pump with the bypass valve fully open and the coarse adjust valve completely closed. Partially open the coarse adjust valve, and slowly close the bypass valve until the desired vacuum is reached. Do not reverse the direction of the bypass valve, as this will cause water to back up into the filter holder. If the desired vacuum is exceeded, either leak-check at this higher vacuum, or end the leak check and start over. 8.1.3.2.4 When the leak check is completed, first slowly remove the plug from the inlet to the probe, filter holder, and immediately turn off the vacuum pump. This prevents the water in the impingers from being forced backward into the filter holder and the silica gel from being entrained backward into the third impinger. 8.1.3.3 Leak Checks During Sample Run. If, during the sampling run, a component (*e.g.,* filter assembly or impinger) change becomes necessary, a leak check shall be conducted immediately before the change is made. The leak check shall be done according to the procedure outlined in section 8.1.3.2, except that it shall be done at a vacuum equal to or greater than the maximum value recorded up to that point in the test. If the leakage rate is found to be no greater than 0.00057 m^3/min (0.020 cfm) or 4 percent of the average sampling rate (whichever is less), the results are acceptable, and no correction will need to be applied to the total volume of dry gas metered; if, however, a higher leakage rate is obtained, either record the leakage rate and plan to correct the sample volume as shown in section 12.3 of Method 5, or void the sample run.

Note: Immediately after component changes, leak checks are optional. If such leak checks are done, the procedure outlined in section 8.1.3.2 should be used.

8.1.3.4 Post-Test Leak Check. A leak check of the sampling train is mandatory at the conclusion of each sampling run. The leak check shall be performed in accordance with the procedures outlined in section 8.1.3.2, except that it shall be conducted at a vacuum equal to or greater than the maximum value reached during the sampling run. If the leakage rate is found to be no greater than 0.00057 m^3 min (0.020 cfm) or 4 percent of the average sampling rate (whichever is less), the results are acceptable, and no correction need be applied to the total volume of dry gas metered. If, however, a higher leakage rate is obtained, either record the leakage rate and correct the sample volume as shown in section 12.3 of Method 5 or void the sampling run.

* * * * *

12.1.3 Volume of Water Collected in Silica Gel.

$$V_{wsg(std)} = \frac{(W_f - W_i) R T_{std}}{P_{std} M_w K_2} \quad Eq.\ 4\text{-}2$$

$$= K_3 (W_f - W_i)$$

Where:

K_3 = 0.001335 m³/g for metric units = 0.04716 ft³/g for English units.

* * * * *

Method 5—Determination of Particulate Matter Emissions From Stationary Sources

* * * * *

12.3 Dry Gas Volume. Correct the sample volume measured by the dry gas meter to standard conditions (20 °C, 760mm Hg or 68 °F, 29.92 in. Hg) by using Equation 5–1.

$$V_{m(std)} = V_m Y \frac{T_{std}\left(P_{bar} + \frac{\Delta H}{13.6}\right)}{T_m P_{std}} \quad Eq. 5-1$$

$$= K_1 V_m Y \frac{P_{bar} + \left(\frac{\Delta H}{13.6}\right)}{T_m}$$

Where:

K_1 = 0.38572 °K/mm Hg for metric units = 17.636 °R/in. Hg for English units.

Note: Equation 5–1 can be used as written unless the leakage rate observed during any of the mandatory leak checks (*i.e.,* the post-test leak check or leak checks conducted prior to component changes) exceeds L_a. If L_p or L_i exceeds La, Equation 5–1 must be modified as follows:

(a) Case I. No component changes made during sampling run. In this case, replace V_m in Equation 5–1 with the expression:

$$(V_m - (L_p - L_a)\theta)$$

(b) Case II. One or more component changes made during the sampling run. In this case, replace Vm in Equation 5–1 by the expression:

$$\left[V_m - (L_1 - L_a)\theta_1 - \sum_{i=2}^{n} (L_1 - L_a)\theta_p\right]$$

and substitute only for those leakage rates (L_i or L_p) which exceed L_a.

* * * * *

12.11.1 Calculation from Raw Data.

$$I = \frac{100 T_s \left[K_4 V_{1c} + \frac{V_m Y}{T_m}\left(P_{bar} + \frac{\Delta H}{13.6}\right)\right.}{60 \theta v_s P_s A_n} \quad Eq.\ 5.7$$

Where:

K_4 = 0.003456 ((mm Hg)(m³))/((ml)(°K)) for metric units,

= 0.002668 ((in. Hg)(ft³))/((ml)(°R)) for English units.

12.11.2 Calculation from Intermediate Values.

$$I = \frac{T_s V_{m(std)} P_{std} 100}{T_{std} v_s \theta A_n P_s 60 (1 - B_{ws})} \quad Eq.\ 5\text{-}8$$

$$= K_5 \frac{T_s V_{m(std)}}{T_{std} v_s A_n \theta (1 - B_{ws})}$$

Where:

K_5 = 4.3209 for metric units = 0.09450 for English units.

* * * * *

16.1.1.4 Calculate flow rate, Q, for each run using the wet test meter volume, V_w, and the run time, θ. Calculate the DGM coefficient, Y_{ds}, for each run. These calculations are as follows:

$$Q = K_1 \frac{P_{bar} V_w}{(T_w + T_{std})\theta} \quad Eq.\ 5\text{-}9$$

$$Y_{ds} = \frac{V_w (T_{ds} + T_{std}) P_{bar}}{V_{ds}(T_w + T_{std})(P_{bar} + \frac{\Delta p}{13.6})} \quad Eq.\ 5\text{-}10$$

Where:

K_1 = 0.38572 °K/mm Hg for metric units = 17.636 °R/in. Hg for English units.

V_w = Wet test meter volume, liter (ft3).

V_{ds} = Dry gas meter volume, liter (ft3).

T_{ds} = Average dry gas meter temperature, °C (°F).

T_{adj} = 273.15 °C for metric units = 459.67 °F for English units.

T_w = Average wet test meter temperature, °C (°F).

P_{bar} = Barometric pressure, mm Hg (in. Hg).

Δp = Dry gas meter inlet differential pressure, mm H_2O (in. H_2O).

θ = Run time, min.

* * * * *

16.2.3.3 Calculate the standard volumes of air passed through the DGM and the critical orifices, and calculate the DGM calibration factor, Y, using the equations below:

$$V_{m(std)} = \frac{K_1 V_m [P_{bar} + \left(\frac{\Delta H}{13.6}\right)]}{T_m} \quad Eq.\ 5\text{-}12$$

$$V_{cr(std)} = K' \frac{P_{bar}\theta}{\sqrt{T_{amb}}} \quad Eq.\ 5\text{-}13$$

$$Y = \frac{P_{bar}\theta}{V_{m(std)}} \quad \text{Eq. 5-14}$$

Where:

$V_{cr(std)}$ = Volume of gas sample passed through the critical orifice, corrected to standard conditions, dscm (dscf).

K_1 = 0.38572 °K/mm Hg for metric units = 17.636 °R/in. Hg for English units.

* * * * *

[FR Doc. 2021–05761 Filed 3–22–21; 8:45 am]

BILLING CODE 6560–50–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

42 CFR Part 51c

RIN 0906–AB25

Implementation of Executive Order on Access to Affordable Life-Saving Medications; Final Rule; Delay of Effective Date

AGENCY: Health Resources and Services Administration (HRSA), Department of Health and Human Services (HHS).

ACTION: Final rule; delay of effective date.

SUMMARY: This final rule implements a further delay until July 20, 2021, of the effective date of the rule entitled ''Implementation of Executive Order on Access to Affordable Life-saving Medications'' published in the **Federal Register** on December 23, 2020. This rule was scheduled to take effect on March 22, 2021, after a delay from its original effective date of January 22, 2021. HHS is delaying the effective date of the rule to July 20, 2021, to ensure that implementation of the rule does not impede HHS's and health centers' immediate priority work, on a nationwide basis, of responding to and mitigating the spread of COVID–19, including ensuring widespread and equitable access to COVID–19 vaccines, and maintaining the delivery of comprehensive primary health services to medically underserved populations, while considering how to address administrative/implementation issues raised by commenters and further address comments regarding the impact of the rule.

DATES: As of March 22, 2021, the effective date of the final rule published at 85 FR 83822 (December 23, 2020), which was delayed at 86 FR 7059 (January 26, 2021), is further delayed until July 20, 2021.

FOR FURTHER INFORMATION CONTACT: Jennifer Joseph, Director, Office of Policy and Program Development, Bureau of Primary Health Care, HRSA, 5600 Fishers Lane, Rockville, MD 20857; by email at *jjoseph@hrsa.gov;* telephone: 301–594–4300; fax: 301–594–4997.

SUPPLEMENTARY INFORMATION:

I. Public Participation

On March 9, 2021, the Office of the Federal Register placed a HHS notice of proposed rulemaking (NPRM) on file for public inspection. This NPRM was published in the **Federal Register** on March 11, 2021, proposing to further delay, until July 20, 2021, the effective date of the rule entitled ''Implementation of Executive Order on Access to Affordable Life-saving Medications'' published in the **Federal Register** on December 23, 2020. The comment period closed on March 14, 2021, with HHS receiving 198 comments on the proposed delay.

Section 553(d) of the Administrative Procedure Act (APA) (5 U.S.C. 551 *et* requirements, definitions, and selection criteria will impose no burden on small entities unless they applied for funding under the program. We expect that in determining whether to apply for PN program funds, an applicant will evaluate the requirements of preparing an application and any associated costs, and weigh them against the benefits likely to be achieved by receiving a PN program grant. An applicant will probably apply only if it determines that the likely benefits exceed the costs of preparing an application.

We believe that the priorities, requirements, definitions, and selection criteria will not impose any additional burden on a small entity applying for a grant than the entity would face in the absence of this regulatory action. That is, the length of the applications those entities would submit in the absence of this regulatory action and the time needed to prepare an application would likely be the same.

This regulatory action will not have a significant economic impact on a small entity once it receives a grant because it will be able to meet the costs of compliance using the funds provided under this program.

Paperwork Reduction Act of 1995: The proposed priorities, requirements, definitions, and selection criteria contain information collection requirements that are approved by OMB under OMB control number 1894–0006; the proposed priorities, requirements, definitions, and selection criteria do not affect the currently approved data collection.

Intergovernmental Review: This program is subject to Executive Order 12372 and the regulations in 34 CFR part 79. One of the objectives of the Executive order is to foster an intergovernmental partnership and a strengthened federalism. The Executive order relies on processes developed by State and local governments for coordination and review of proposed Federal financial assistance. This document provides early notification of our specific plans and actions for this program.

Accessible Format: On request to the program contact person listed under **FOR FURTHER INFORMATION CONTACT**, individuals with disabilities can obtain this document and a copy of the application package in an accessible format. The Department will provide the requestor with an accessible format that may include Rich Text Format (RTF) or text format (txt), a thumb drive, an MP3 file, braille, large print, audiotape, or compact disc, or other accessible format.

Electronic Access to This Document: The official version of this document is the document published in the **Federal Register**. You may access the official edition of the **Federal Register** and the Code of Federal Regulations at: *www.govinfo.gov.* At this site you can view this document, as well as all other documents of this Department published in the **Federal Register,** in text or Portable Document Format (PDF). To use PDF you must have Adobe Acrobat Reader, which is available free at the site.

You may also access documents of the Department published in the **Federal Register** by using the article search feature at: *www.federalregister.gov.* Specifically, through the advanced search feature at this site, you can limit your search to documents published by the Department.

Frank T. Brogan,

Assistant Secretary for Elementary and Secondary Education.

[FR Doc. 2021–00902 Filed 1–15–21; 8:45 am]

BILLING CODE 4000–01–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[EPA–HQ–OAR–2020–0372; FRL–10019–21–OAR]

RIN 2060–AU91

Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: The U.S. Environmental Protection Agency (EPA) is finalizing amendments to the Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984. We are finalizing specific amendments that would allow owners or operators of storage vessels subject to the Standards of Performance for Volatile Organic Liquid Storage Vessels and equipped with either an external floating roof (EFR) or internal floating roof (IFR) to voluntarily elect to comply with the requirements specified in the National Emission Standards for Storage Vessels (Tanks)—Control Level 2, as an alternative standard, in lieu of the requirements specified in the Standards of Performance for Volatile Organic Liquid Storage Vessels, subject to certain caveats and exceptions for monitoring, recordkeeping, and reporting.

DATES: The final rule is effective on January 19, 2021.

ADDRESSES: The EPA has established a docket for this rulemaking under Docket ID No. EPA–HQ–OAR–2020–0372. All documents in the docket are listed on the *https://www.regulations.gov/* website. Although listed, some information is not publicly available, *e.g.,* Confidential Business Information or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the internet and will be publicly available only in hard copy form. Publicly available docket materials are available electronically on the *https://www.regulations.gov/* website. Out of an abundance of caution for members of the public and our staff, the EPA Docket Center and Reading Room are closed to the public, with limited exceptions, to reduce the risk of transmitting COVID–19. Our Docket Center staff will continue to provide remote customer service via email, phone, and webform. For further information and updates on EPA Docket Center services, please visit us online at *https://www.epa.gov/dockets.* The EPA continues to carefully and continuously monitor information from the Center for Disease Control, local area health departments, and our federal partners so that we can respond rapidly as conditions change regarding COVID–19.

FOR FURTHER INFORMATION CONTACT: For questions about this final action, contact Mr. Neil Feinberg, Sector Policies and Programs Division (E143–01), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711; telephone number: (919) 541–2214; fax number: (919) 541–0516; and email address: *feinberg.stephen@epa.gov.*

SUPPLEMENTARY INFORMATION: *Preamble acronyms and abbreviations.* We use multiple acronyms and terms in this preamble. While this list may not be exhaustive, to ease the reading of this preamble and for reference purposes, the EPA defines the following terms and acronyms here:

CAA Clean Air Act
CFR Code of Federal Regulations
EFR external floating roof
EPA Environmental Protection Agency
ICR Information Collection Request
IFR internal floating roof
kPa kilopascals
m3 cubic meters

NAICS North American Industry Classification System
NESHAP national emission standards for hazardous air pollutants
NSPS new source performance standards
OMB Office of Management and Budget
PRA Paperwork Reduction Act
tpy tons per year
VOC volatile organic compound(s)

Background information. On October 16, 2020, the EPA proposed revisions to the Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984. 85 FR 65774. In this action, the EPA is finalizing decisions and revisions for the rule. We summarize the in-scope comments we timely received regarding the proposed rule and provide our responses in this preamble. A ''track changes'' version of the regulatory language that incorporates the changes in this action is available in the docket.

Organization of this document. The information in this preamble is organized as follows:

I. General Information
A. Does this action apply to me?
B. Where can I get a copy of this document and other related information?
C. Judicial Review and Administrative Reconsideration
II. Background and Final Amendments
III. Public Comments and Responses
IV. Impacts of the Final Rule
A. What are the air quality impacts?
B. What are the cost impacts?
C. What are the economic impacts?
D. What are the benefits?
V. Statutory and Executive Order Reviews
A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review
B. Executive Order 13771: Reducing Regulations and Controlling Regulatory Costs
C. Paperwork Reduction Act (PRA)
D. Regulatory Flexibility Act (RFA)
E. Unfunded Mandates Reform Act (UMRA)
F. Executive Order 13132: Federalism
G. Executive Order 13175: Consultation and Coordination with Indian Tribal Governments
H. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks
I. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use
J. National Technology Transfer and Advancement Act (NTTAA)
K. Executive Order 12898: Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations
L. Congressional Review Act (CRA)

I. General Information

A. Does this action apply to me?

Regulated entities. Categories and entities potentially affected by this action are shown in Table 1 of this preamble.

TABLE 1—EXAMPLES OF POTENTIALLY AFFECTED ENTITIES BY CATEGORY

Category	NAICS code [1]	Examples of potentially regulated entities
Industrial	325	Chemical manufacturing facilities.
	324	Petroleum and coal products manufacturing facilities.
	422710	Petroleum bulk stations and terminals.

[1] North American Industry Classification System.

This table is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be affected by this action. To determine whether your entity is affected by this action, you should carefully examine the applicability criteria found in the final rule. If you have questions regarding the applicability of this action to a particular entity, consult the person listed in the **FOR FURTHER INFORMATION CONTACT** section of this preamble, your delegated authority, or your EPA Regional representative listed in 40 CFR 60.4 (General Provisions).

B. Where can I get a copy of this document and other related information?

In addition to being available in the docket, an electronic copy of this final action will be available on the internet. Following signature by the EPA Administrator, the EPA will post a copy of this final action at *https://www.epa.gov/stationary-sources-air-pollution/volatile-organic-liquid-storage-vessels-including-petroleum-storage.* Following publication in the **Federal Register**, the EPA will post the **Federal Register** version of the final rule and key technical documents at this same website.

C. Judicial Review and Administrative Reconsideration

Under Clean Air Act (CAA) section 307(b)(1), judicial review of this final action is available only by filing a petition for review in the United States Court of Appeals for the District of Columbia Circuit by March 22, 2021. Under CAA section 307(b)(2), the requirements established by this final rule may not be challenged separately in any civil or criminal proceedings brought by the EPA to enforce the requirements.

Section 307(d)(7)(B) of the CAA further provides that ''[o]nly an objection to a rule or procedure which was raised with reasonable specificity during the period for public comment (including any public hearing) may be raised during judicial review.'' This section also provides a mechanism for the EPA to convene a proceeding for reconsideration, ''[i]f the person raising an objection can demonstrate to the EPA that it was impracticable to raise such objection within [the period for public comment] or if the grounds for such objection arose after the period for public comment, (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule.'' Any person seeking to make such a demonstration to us should submit a Petition for Reconsideration to the Office of the Administrator, U.S. Environmental Protection Agency, Room 3000, WJC West Building, 1200 Pennsylvania Ave. NW, Washington, DC 20460, with a copy to both the person(s) listed in the preceding **FOR FURTHER INFORMATION CONTACT** section, and the Associate General Counsel for the Air and Radiation Law Office, Office of General Counsel (Mail Code 2344A), U.S. Environmental Protection Agency, 1200 Pennsylvania Ave. NW, Washington, DC 20460.

II. Background and Final Amendments

Pursuant to the EPA's authority under CAA section 111, the Agency proposed (49 FR 29698, July 23, 1984) and promulgated (52 FR 11420, April 8, 1987) new source performance standards (NSPS) at 40 CFR part 60, subpart Kb, for Volatile Organic Liquid Storage Vessels, Including Petroleum Liquid Storage Vessels, for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984. To reduce volatile organic compound (VOC) emissions from storage vessels with a capacity of 75 cubic meters (m^3) or more that store organic liquids with a true vapor pressure over 27.6 kilopascals (kPa), and from storage vessels with a capacity of 151 m^3 or more that store organic liquids with a true vapor pressure over 5.2 kPa, NSPS subpart Kb requires the use of either an EFR, an IFR, or a closed vent system and a control device. See 40 CFR 60.110b(a) and 60.112b(a) and (b).[1] NSPS subpart Kb also specifies testing, monitoring, recordkeeping, reporting, and other requirements in 40 CFR 60.113b through 60.116b to ensure compliance with the standards. More specifically, 40 CFR 60.113b requires, among other things, that certain inspections for IFR and EFR occur at least once within certain defined timeframes (such as at least once every year, 5 years, or 10 years). Storage vessels with an EFR consist of an open-top cylindrical steel shell equipped with a deck that floats on the surface of the stored liquid (commonly referred to as a floating roof). Storage vessels with an IFR are fixed roof vessels[2] that also have a deck internal to the tank that floats on the liquid surface within the fixed roof vessel (commonly referred to as an internal floating roof).

The standards in NSPS subpart Kb for storage vessels with an EFR or IFR are a combination of a design, equipment, work practice, and operational standards set pursuant to CAA section 111(h). These standards require, among other things, that a rim seal be installed continuously around the circumference of the vessel (between the inner wall of the vessel and the floating roof) to prevent VOC from escaping to the atmosphere through gaps between the floating roof and the inner wall of the storage vessel. Similarly, NSPS subpart Kb requires deck fittings[3] on the floating roof to be equipped with a gasketed cover or lid that is kept in the closed position at all times (*i.e.,* no visible gap), except when the device (the deck fitting) is in actual use, to prevent VOC emissions from escaping through the deck fittings. In general, NSPS subpart Kb requires owners or operators to conduct visual inspections to check for defects in the floating roof, rim seals, and deck fittings (*e.g.,* holes, tears, or other openings in the rim seal, or covers and lids on deck fittings that no longer close properly) that could expose the liquid surface to the atmosphere and potentially result in VOC emission losses through rim seals and deck fittings.[4]

Since promulgation of NSPS subpart Kb, the EPA promulgated 40 CFR part 63, subpart WW, which is applicable to storage vessels containing organic materials, as part of the generic maximum achievable control technology standards program for setting national emission standards for hazardous air pollutants (NESHAP) under CAA section 112. See 64 FR 34854 (June 29, 1999). NESHAP subpart WW was developed for the purpose of providing consistent EFR and IFR requirements for storage vessels that could be referenced by multiple NESHAP subparts. Like the NSPS subpart Kb standards for floating roof tanks, NESHAP subpart WW is comprised of a combination of design, equipment, work practice, and operational standards. See proposed rule for NESHAP subpart WW (63 FR 55178, 55196 (October 14, 1998)). Both rules specify monitoring, recordkeeping, and reporting requirements for storage vessels equipped with EFR or IFR, and both include numerous requirements for inspections that occur at least once within certain defined timeframes. See 40 CFR 63.1063 for the IFR and EFR inspection requirements of NESHAP subpart WW. The inspections required by NESHAP subpart WW are intended to achieve the same goals as those inspections required by NSPS subpart Kb (*e.g.,* both rules require visual inspections to check for defects in the floating roof, rim seals, and deck fittings). Further, NESHAP subpart WW incorporates technical improvements based on the EPA's experience with implementation of other NESHAP. For storage vessels equipped with either an EFR or IFR, as long as there is visual access (as explained below), NESHAP subpart WW allows that the visual inspection of the floating roof deck, deck fittings, and rim seals may be conducted, while the tank remains in-service, from the top-side of the floating roof (meaning on top of the floating roof, and in the case of an IFR, under the fixed roof and internal to the tank); this is referred to as an in-service top-side of the floating roof visual inspection. In other words, in the case of an IFR, if an owner or operator has physical access to the inside of the tank above the floating roof and a floating roof design which allows inspectors to have visual access to all rim seals and deck fittings of the floating roof (meaning an inspector can see all the components required to be inspected) while the storage vessel is in-service, then NESHAP subpart WW does not require the owner or operator to take the storage vessel out of service to inspect the floating roof, rim seals, and deck fittings in accordance with 40 CFR 63.1063(d)(1).[5] This contrasts with NSPS subpart Kb, which, as explained in the proposed rule, requires that these inspections be conducted when the storage vessel is out-of-service (compare 40 CFR 63.1063(d)(1) with 40 CFR 60.113b(a)(4) and (b)(6)).

Pursuant to the EPA's authority under CAA section 111(h), we proposed amendments to NSPS subpart Kb in a new paragraph (see proposed 85 FR 65782—40 CFR 60.110b(e)(5)) that would allow owners or operators of storage vessels subject to NSPS subpart Kb, and equipped with either an EFR or IFR, the choice to elect to comply with the requirements specified in NESHAP subpart WW as an alternative standard, in lieu of the requirements specified in NSPS subpart Kb. 85 FR 65774 (October 16, 2020). Sources subject to NSPS subpart Kb that are equipped with either an EFR or IFR that elect to utilize the alternative standard would comply with all of the requirements in NESHAP subpart WW instead of the requirements in NSPS subpart Kb, 40 CFR 60.112b through 60.117b, subject to certain caveats and exceptions explained in the proposed rule and below. Among other things, this alternative allows owners or operators of storage vessels subject to NSPS subpart Kb that are equipped with an IFR, and that can meet the visual access requirement of NESHAP subpart WW explained above, to conduct the internal in-service top-side of the floating roof visual inspection pursuant to NESHAP subpart WW, thereby avoiding the need to empty and degas the vessel for the sole purpose of conducting the inspection. Further, we are not changing the underlying monitoring, reporting, or recordkeeping requirements in either NSPS subpart Kb or NESHAP subpart WW (with the

[1] All affected storage vessels storing organic liquids with a true vapor pressure of 76.6 kPa or more must use a closed vent system and a control device. 40 CFR 60.112b(b).

[2] A fixed roof storage vessel consists of a cylindrical steel shell with a permanently affixed roof, which may vary in design from cone or dome-shaped to flat.

[3] Numerous fittings pass through or are attached to floating roof decks to accommodate structural support components or to allow for operational functions. Typical deck fittings include, but are not limited to, the following: Access hatches, gauge floats, gauge-hatch/sample ports, rim vents, deck drains, deck legs, vacuum breakers, and guidepoles. IFR tanks may also have deck seams, fixed-roof support columns, ladders, and/or stub drains.

[4] For details about storage vessel emissions, refer to the Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources, AP–42, Fifth Edition, Chapter 7: Liquid Storage Tanks, dated June 2020, which is available at: *https://www.epa.gov/air-emissions-factors-and-quantification/ap-42-compilation-air-emissions-factors.*

[5] "The inspection may be performed entirely from the top side of the floating roof, as long as there is visual access to all deck components specified in paragraph (a) of this section." 40 CFR 63.1063(d)(1).

exception of some conforming and referencing edits to recordkeeping and reporting as discussed in the proposed rule and below), nor are we changing the applicability criteria in NSPS subpart Kb or NESHAP subpart WW. We are requiring that owners or operators that choose to use this optional alternative standard continue to use the same NSPS subpart Kb procedures for all storage vessels when determining applicability of NSPS subpart Kb; thus, owners or operators that choose to use this alternative must continue to comply with the monitoring requirements of 40 CFR 60.116b(a), (c), (e), and (f)(1), and also must keep other records and furnish other reports (as discussed in the proposed rule and below) in addition to all of the requirements specified in 40 CFR 63.1060 through 63.1067 of NESHAP subpart WW. In addition, because NSPS subpart Kb applies to each single storage vessel (see 40 CFR 60.110b for NSPS subpart Kb applicability and definition of affected facility), this alternative standard would be available for each affected facility as defined in NSPS subpart Kb. In other words, an owner or operator with multiple affected facilities can choose to use (or not use) the alternative for each individual affected facility.

After considering the public comments received, the EPA is finalizing the amendments that were proposed with minimal changes as a result of comments. We are clarifying that the notification for switching to or from the alternative standard is only required for the initial inspection after the switch. We are also correcting typographical errors in NSPS subpart Kb that inadvertently referenced the wrong, nonexistent subparts.

III. Public Comments and Responses

This section presents a summary of the relevant public comments received on the proposed amendments and the EPA's responses. The EPA received five relevant public comments on the proposed amendments, some of which contained portions that were out of scope, and one comment that was entirely out of scope. The comments can be obtained online from the Federal Docket Management System at *https://www.regulations.gov/.*

Comment: One commenter stated that the EPA should consider increasing the required frequency of inspections under the alternative standard, and that the EPA did not offer strong evidence of equivalence between the NSPS subpart Kb requirements and the alternative standard.

Response: As discussed in section III.A of the preamble to the proposed rule, EPA determined that the alternative standard is appropriate because it will achieve a reduction in emissions at least equivalent to the reduction in emissions achieved under NSPS subpart Kb, and that the alternative standard is just as stringent as, if not more stringent than, the underlying standard. This determination was based upon the premise that the proposal would not change the underlying compliance schedule(s) for events (inspections) under NSPS subpart Kb or NESHAP subpart WW. The EPA did not solicit comment on, nor did we intend to make changes to, any other provisions of NSPS subpart Kb or NESHAP subpart WW, including the frequency of inspections required by each of those subparts. Further, the EPA referenced and provided background documentation in the docket to support this equivalency determination (see Docket Item No. EPA–HQ–OAR–2020–0372–0004). The commenter did not explain how the EPA's support of the proposed equivalency determination was inadequate or provide any evidence to support the claimed need of increased inspection frequency. While the commenter states that ''empty vessel inspections'' are ''potentially more comprehensive,'' they offer no explanation for this claim and do not dispute the EPA's explanation that ''[c]onducting the in-service top-side-of-the-floating-roof inspection per NESHAP subpart WW affords the inspector the same ability to examine all the listed components for all of the listed defects/inspection failures as if the storage vessel was emptied and degassed.'' 85 FR 65779. Therefore, the EPA does not find it necessary to increase the required frequency of inspections under the alternative standard in order to determine equivalency for the multiple reasons stated in section III.A of the proposal preamble which are not repeated here.

Comment: One commenter suggested that the EPA consider including additional context for the Agency's explanation regarding the emission reduction potential of allowing compliance with the alternative standard.

Response: The EPA has already included a document in the docket titled ''Impacts for Revision of Internal Floating Roof Storage Vessel (Tank) Inspection Requirements Subject to 40 CFR part 60 Subpart Kb'' (Docket Item No. EPA–HQ–OAR–2020–0372–0005) that explains the air quality impacts of the proposal. This document explains emission releases from tank emptying and degassing events and includes national impact estimates of the potential emissions avoided by the proposal in terms of tons per year (tpy) of VOC. This document already includes information that the commenter suggests should be added. Further, the commenter did not provide any explanation as to why it believes the documentation in the docket at proposal provided inadequate context for understanding the predicted emissions reductions associated with the proposed alternative standard. Therefore, the EPA does not find it necessary to conduct any additional analysis of the air quality impacts associated with the alternative standard.

Comment: Several commenters recommended clarifying that the proposed revisions (the alternative standard) can be used by sources subject to other regulations that reference NSPS subpart Kb, such as the National Emission Standard for Benzene Waste Operations and the Gasoline Distribution MACT. The commenters noted that some emission standards that reference NSPS subpart Kb do not have the same design capacity and vapor pressure thresholds for requiring control as NSPS subpart Kb yet still require compliance with NSPS subpart Kb. The commenter suggested that the language of the proposed revisions be changed to be inclusive of storage vessels subject to those referencing standards.

Response: The EPA did not propose to allow the alternative standard for any sources aside from those that meet the applicability criteria in 40 CFR 60.110b and which are equipped with either an IFR or EFR pursuant to 40 CFR 60.112b(a)(1) or (2). If the EPA were to make the alternative standard available to sources that comply with NSPS subpart Kb via a referencing subpart as commenters suggest, then the EPA would first need to conduct a detailed analysis of how each potential referencing subpart references NSPS subpart Kb. The EPA would then need to include conforming regulations in this rulemaking for recordkeeping, reporting, and applicability of general provisions as needed for those referencing subparts. These time-consuming analyses and associated regulatory amendments are outside the scope of this limited rulemaking. Therefore, we are not making changes to the criteria for storage vessels allowed to use the alternative standard at this time. However, the EPA will consider addressing the commenters' suggestion should the Agency decide to propose additional amendments to NSPS subpart

Kb in the future via a different rulemaking process.

Comment: Several commenters recommended clarifying the reporting requirements of the proposed revisions. The commenters stated that the proposed revisions at 40 CFR 60.110b(e)(5)(iv)(B) and (C) require that each affected facility using the alternative standard submit reports under 40 CFR 63.1066 of NESHAP subpart WW; however, it was unclear when these reports need to be submitted. The commenter stated that it was unclear whether these reports should be submitted only with the first inspection using the alternative standard or with every subsequent inspection as well. The commenter stated that if the report was only required for the first inspection, this would be redundant with the reporting requirement in 40 CFR 60.110b(e)(5)(iv)(A). Alternatively, if this requirement were for every inspection, this requirement would conflict with the requirement in 40 CFR 60.110b(e)(5)(iv)(F)(*2*) to submit inspection reports only when inspection failures occur.

Response: The EPA intended to require only the initial notification that occurs after electing to comply with the alternative standard under 40 CFR 60.110b(e)(5)(iv)(A). Therefore, we agree with the commenters' suggestion to remove the proposed provision that would have required inclusion of this notification with subsequent reports and have made the corresponding changes in the final rule language.

Comment: Several commenters suggested clarifying the reporting frequency in the proposed revisions. The commenters stated that maintaining the reporting frequency of NSPS subpart Kb ''could lead to inconsistent and duplicative reporting requirements which . . . EPA has repeatedly acknowledged impose unnecessary burden with no environmental benefit,'' and that the EPA should allow semi-annual reporting frequency. The commenters stated that a semi-annual reporting requirement would be more consistent with reporting requirements established after the promulgation of NSPS subpart Kb in 1987. They also stated that the EPA allows storage vessels subject to both NSPS subpart Kb and a NESHAP to submit compliance reports on a semi-annual basis.

Response: As the EPA explained in section V of the proposed amendments, the Agency did not solicit comment on, nor did we intend to make changes to, any other provisions of NSPS subpart Kb or NESHAP subpart WW aside from incorporating the proposed alternative standard. As such, the EPA is not modifying the reporting schedule for NSPS subpart Kb because such a change would be outside the scope of this limited rulemaking which was intended only to incorporate the proposed alternative standard. It was not the EPA's intent to make changes to the underlying reporting schedules in NSPS subpart Kb. However, the EPA will consider addressing the commenters' suggestion should the Agency decide to propose additional amendments to NSPS subpart Kb in the future via a different rulemaking process.

Comment: Several commenters recommended clarifying the inspection deadlines of the alternative standard. The commenters stated that the EPA should allow inspections to occur at any point within the specified calendar period (*e.g.,* within each calendar year rather than a specific 1-year interval), provided that a minimum amount of time has passed since the last inspection.

Response: As the EPA explained in section V of the proposed amendments, the Agency did not solicit comment on, nor did we intend to make changes to, any other provisions of NSPS subpart Kb or NESHAP subpart WW aside from incorporating the proposed alternative standard. As such, the EPA is not modifying the inspection schedule requirements for NSPS subpart Kb because such a modification would be outside the scope of this limited rulemaking which was intended only to incorporate the proposed alternative standard. It was not the EPA's intent to make changes to the underlying inspection schedules in NSPS subpart Kb. However, the EPA will consider addressing the commenters' suggestion should the Agency decide to propose additional amendments to NSPS subpart Kb in the future via a different rulemaking process.

Comment: One commenter suggested that the EPA make technical corrections to 40 CFR 60.115b(a)(4) and (b) to correct previous inadvertent errors in citations.

Response: The EPA agrees with the commenter and has corrected 40 CFR 60.115b(a)(4) to reference 40 CFR 60.112b(a)(1) and 40 CFR 60.115b(b) to reference 40 CFR 60.112b(a)(2). While this comment and the EPA's associated revisions do not fit squarely within the scope of the proposal to incorporate the alternative standard, and do address a separate provision of NSPS subpart Kb unrelated to the alternative standard, the EPA found it appropriate to make these changes because commenters identified a genuine typographical error. The EPA's revisions here will not alter how sources and/or the Agency have been implementing NSPS subpart Kb in any way. The EPA finds it appropriate and convenient to use this rulemaking to correct the inadvertent typographical error.

IV. Impacts of the Final Rule

A. What are the air quality impacts?

We estimate that nationwide VOC emissions reductions would range from 65.8 tpy to 83.3 tpy as a result of the amendments. As explained at proposal, the alternative standard allows owners or operators to avoid emptying and degassing storage vessels in order to perform certain inspections, thereby reducing emissions caused by degassing vapors which have historically been vented to the atmosphere or sent to control equipment. These emissions reductions were documented in the memorandum, *Impacts for Revision of Internal Floating Roof Storage Vessel (Tank) Inspection Requirements Subject to 40 CFR part 60 Subpart Kb* (see Docket ID No. EPA–HQ–OAR–0372–0005).

B. What are the cost impacts?

We estimate that the amendments will result in a nationwide net cost savings of between $768,000 and $1,091,000 per year (in 2019 dollars). For further information on the cost savings associated with the amendments, see the memorandum, *Impacts for Revision of Internal Floating Roof Storage Vessel (Tank) Inspection Requirements Subject to 40 CFR part 60 Subpart Kb* (see Docket ID No. EPA–HQ–OAR–0372–0005).

C. What are the economic impacts?

As noted earlier, we estimated a nationwide cost savings associated with the amendments. Therefore, we do not expect the actions in this rulemaking to result in business closures, significant price increases or decreases in affected output, or substantial profit loss. For more information, refer to the *Economic Impact Analysis for the Proposed Alternative Standard Available to Floating Roof Storage Vessels (Tanks) Subject to 40 CFR part 60 Subpart Kb,* which is in the docket for this rulemaking.

D. What are the benefits?

The EPA did not monetize the benefits from the estimated emission reductions of VOC associated with this action. However, we expect this action would provide benefits associated with VOC emission reductions.

V. Statutory and Executive Order Reviews

Additional information about these statutes and Executive orders can be found at *https://www.epa.gov/laws-regulations/laws-and-executive-orders.*

A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review

This action is not a significant regulatory action and was, therefore, not submitted to the Office of Management and Budget (OMB) for review.

B. Executive Order 13771: Reducing Regulations and Controlling Regulatory Costs

This action is considered an Executive Order 13771 deregulatory action. Details on the estimated cost savings of this rule can be found in the EPA's analysis of the potential costs and benefits associated with this action.

C. Paperwork Reduction Act (PRA)

The information collection activities in this rule have been submitted for approval to the OMB under the PRA. The Information Collection Request (ICR) document that the EPA prepared has been assigned EPA ICR number 1854.13. 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.

See section III.A of the preamble for the proposed rule (''What actions are we proposing?'') for a description of the alternative standard. Information about inspection activities related to NSPS subpart Kb is collected to assure compliance with NSPS subpart Kb. Most of the costs associated with the alternative standard are associated with labor hours. The time needed to conduct an in-service top-side-of-the-floating-roof visual inspection pursuant to the requirements in NESHAP subpart WW is expected to be less than the time needed to complete an out-of-service inspection pursuant to NSPS subpart Kb. Therefore, we anticipate a cost savings. This ICR documents the incremental burden imposed by the final amendments only. In summary, there is a decrease in the burden (labor hours) documented in this ICR due a reduction in the number of respondents (storage vessels subject to NSPS subpart Kb) that would be required to empty and degas their storage vessels equipped with an IFR.

Respondents/affected entities: Owners or operators of storage vessels constructed after July 23, 1984, that have capacity greater than or equal to 75 m^3 used to store volatile organic liquids (including petroleum liquids) with a true vapor pressure greater than or equal to 3.5 kPa, and storage vessels constructed after July 23, 1984, that have capacity between 75 and 151 m^3 capacity for which the true vapor pressure of the stored liquid is greater than or equal to 15 kPa.

Respondent's obligation to respond: Mandatory (40 CFR part 60, subpart Kb, and 40 CFR part 63, subpart WW).

Estimated number of respondents: 385 facilities.

Frequency of response: Variable (storage vessel specific).

Total estimated burden: A reduction of 6,210 hours (per year). Burden is defined at 5 CFR 1320.3(b).

Total estimated cost: A savings of $930,000 (per year), includes a savings of $466,000 annualized capital or operation and maintenance costs.

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.

D. 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. The alternative standard is optional; therefore, small entities are not required to comply with the alternative.

E. Unfunded Mandates Reform Act (UMRA)

This action does not contain any unfunded mandate as described in UMRA, 2 U.S.C. 1531–1538, and does not significantly or uniquely affect small governments. The action imposes no enforceable duty on any state, local, or tribal governments or the private sector.

F. Executive Order 13132: Federalism

This action does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the National Government and the states, or on the distribution of power and responsibilities among the various levels of government.

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

This action does not have tribal implications as specified in Executive Order 13175. It will not have substantial direct effects on tribal governments, on the relationship between the Federal Government and Indian tribes, or on the distribution of power and responsibilities between the Federal Government and Indian tribes, as specified in Executive Order 13175. Thus, Executive Order 13175 does not apply to this action.

Consistent with the EPA Policy on Consultation and Coordination with Indian Tribes, the EPA offered consultation with tribal officials during the development of this action; however, the Agency did not receive a request for consultation. The EPA held a webinar with communities on November 10, 2020, which included tribes during the public comment period to inform them of the content of the proposed rule and to encourage them to submit comments on the proposed rule.

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

The EPA interprets Executive Order 13045 as applying only to those regulatory actions that concern environmental health or safety risks that the EPA has reason to believe may disproportionately affect children, per the definition of ''covered regulatory action'' in section 2–202 of the Executive order. This action is not subject to Executive Order 13045 because it does not concern an environmental health risk or safety risk.

I. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

This action is not subject to Executive Order 13211 because it is not a significant regulatory action under Executive Order 12866.

J. National Technology Transfer and Advancement Act (NTTAA)

This rulemaking does not involve technical standards.

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

The EPA believes that this action does not have disproportionately high and adverse human health or environmental effects on minority populations, low-income populations, and/or indigenous peoples, as specified in Executive Order

12898 (59 FR 7629, February 16, 1994). Although the proposed alternative is optional, the alternative standard is at least as stringent as the current applicable requirements.

As discussed above in section V.G, a webinar was held for community groups which included environmental justice communities.

L. Congressional Review Act (CRA)

This action is subject to the CRA, and the EPA will submit a rule report to each House of the Congress and to the Comptroller General of the United States. This action is not a ''major rule'' as defined by 5 U.S.C. 804(2).

List of Subjects in 40 CFR Part 60

Environmental protection, Air pollution control, Reporting and recordkeeping requirements, Volatile organic compounds.

Andrew Wheeler,

Administrator.

For the reasons set forth in the preamble, the EPA is amending 40 CFR part 60 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.*

Subpart Kb—Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984

■ 2. Section 60.110b is amended by adding paragraph (e)(5) to read as follows:

§ 60.110b Applicability and designation of affected facility.

* * * * *

(e) * * *

(5) *Option to comply with part 63, subpart WW, of this chapter.* Except as specified in paragraphs (e)(5)(i) through (iv) of this section, owners or operators may choose to comply with 40 CFR part 63, subpart WW, to satisfy the requirements of §§ 60.112b through 60.117b for storage vessels either with a design capacity greater than or equal to 151 m^3 containing a VOL that, as stored, has a maximum true vapor pressure equal to or greater than 5.2 kPa but less than 76.6 kPa, or with a design capacity greater than or equal to 75 m^3 but less than 151 m^3 containing a VOL that, as stored, has a maximum true vapor pressure equal to or greater than 27.6 kPa but less than 76.6 kPa.

(i) The general provisions in subpart A of this part apply instead of the general provisions in subpart A of part 63 of this chapter.

(ii) Where terms are defined in both this subpart and 40 CFR part 63, subpart WW, the definitions in this subpart apply.

(iii) Owners or operators who choose to comply with 40 CFR part 63, subpart WW, also must comply with the monitoring requirements of § 60.116b(a), (c), (e), and (f)(1), except as specified in paragraphs (e)(5)(iii)(A) through (C) of this section.

(A) The reference to all records applies only to the records required by § 60.116b(c);

(B) The reference to § 60.116b(b) does not apply; and

(C) The reference to § 60.116b(g) does not apply.

(iv) Owners or operators who choose to comply with 40 CFR part 63, subpart WW, must also keep records and furnish reports as specified in paragraphs (e)(5)(iv)(A) through (F) of this section.

(A) For each affected facility, the owner or operator must notify the Administrator at least 30 days before the first inspection is conducted under 40 CFR part 63, subpart WW. After this notification is submitted to the Administrator, the owner or operator must continue to comply with the alternative standard described in this paragraph (e)(5) until the owner or operator submits another notification to the Administrator indicating the affected facility is using the requirements of §§ 60.112b through 60.117b instead of the alternative standard described in this paragraph (e)(5). The compliance schedule for events does not reset upon switching between compliance with this subpart and 40 CFR part 63, subpart WW.

(B) Keep a record of each affected facility using the alternative standard described in this paragraph (e)(5) when conducting an inspection required by § 63.1063(c)(1) of this chapter.

(C) Keep a record of each affected facility using the alternative standard described in this paragraph (e)(5) when conducting an inspection required by § 63.1063(c)(2) of this chapter.

(D) Copies of all records and reports kept pursuant to § 60.115b(a) and (b) that have not met the 2-year record retention required by the introductory text of § 60.115b must be kept for an additional 2 years after the date of submittal of the inspection notification specified in paragraph (e)(5)(iv)(A) of this section, indicating the affected facility is using the requirements of 40 CFR part 63, subpart WW.

(E) Copies of all records and reports kept pursuant to § 63.1065 of this chapter that have not met the 5-year record retention required by the introductory text of § 63.1065 must be kept for an additional 5 years after the date of submittal of the notification specified in paragraph (e)(5)(iv)(A) of this section, indicating the affected facility is using the requirements of §§ 60.112b through 60.117b.

(F) The following exceptions to the reporting requirements of § 63.1066 of this chapter apply:

(*1*) The notification of initial startup required under § 63.1066(a)(1) and (2) of this chapter must be submitted as an attachment to the notification required by §§ 60.7(a)(3) and 60.115b(a)(1);

(*2*) The reference in § 63.1066(b)(2) of this chapter to periodic reports ''when inspection failures occur'' means to submit inspections results within 60 days of the initial gap measurements required by § 63.1063(c)(2)(i) of this chapter and within 30 days of all other inspections required by § 63.1063(c)(1) and (2) of this chapter.

■ 3. Section 60.115b is amended by revising paragraph (a)(4) and the introductory text of paragraph (b) to read as follows:

§ 60.115b Reporting and recordkeeping requirements.

* * * * *

(a) * * *

(4) After each inspection required by § 60.113b(a)(3) that finds holes or tears in the seal or seal fabric, or defects in the internal floating roof, or other control equipment defects listed in § 60.113b(a)(3)(ii), a report shall be furnished to the Administrator within 30 days of the inspection. The report shall identify the storage vessel and the reason it did not meet the specifications of § 60.112b(a)(1) or § 60.113b(a)(3) and list each repair made.

(b) After installing control equipment in accordance with § 60.112b(a)(2) (external floating roof), the owner or operator shall meet the following requirements.

* * * * *

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