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ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[EPA–HQ–OAR–2017–0483; FRL–9984–43–OAR]

RIN 2060–AT54

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

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: This action proposes reconsideration amendments to the new source performance standards (NSPS) at 40 Code of Federal Regulations (CFR) part 60, subpart OOOOa (2016 NSPS OOOOa). The Environmental Protection Agency (EPA) received petitions for reconsideration on the 2016 NSPS OOOOa. In 2017, the EPA granted reconsideration on the fugitive emissions requirements, well site pneumatic pump standards, and the requirements for certification of closed vent systems by a professional engineer based on specific objections to these requirements. This action proposes amendments and clarifications as a result of reconsideration of these issues. The proposed amendments also address other issues raised for reconsideration and make technical corrections and amendments to further clarify the rule.

DATES:

Comments. Comments must be received on or before December 17, 2018. Under the Paperwork Reduction Act (PRA), comments on the information collection provisions are best assured of consideration if the Office of Management and Budget (OMB) receives a copy of your comments on or before December 17, 2018.

Public Hearing. EPA is planning to hold at least one public hearing in response to this proposed action. Information about the hearing, including location, date, and time, along with instructions on how to register to speak at the hearing, will be published in a second **Federal Register** notice.

ADDRESSES:

Comments. Submit your comments, identified by Docket ID No. EPA–HQ–OAR–2017–0483, at *https://www.regulations.gov.* Follow the online instructions for submitting comments. Once submitted, comments cannot be edited or removed from *Regulations.gov.* (See **SUPPLEMENTARY INFORMATION** for detail about how the EPA treats submitted comments.) *Regulations.gov* is our preferred method of receiving comments. However, other submission methods are accepted:

- *Email: a-and-r-docket@epa.gov.* Include Docket ID No. EPA–HQ–OAR–2017–0483 in the subject line of the message.
- *Fax:* (202) 566–9744. Attention Docket ID No. EPA–HQ–OAR–2017–0483.
- *Mail:* To ship or send mail via the United States Postal Service, use the following address: U.S. Environmental Protection Agency, EPA Docket Center, Docket ID No. EPA–HQ–OAR–2017–0483, Mail Code 28221T, 1200 Pennsylvania Avenue NW, Washington, DC 20460.
- *Hand/Courier Delivery:* Use the following Docket Center address if you are using express mail, commercial delivery, hand delivery, or courier: EPA Docket Center, EPA WJC West Building, Room 3334, 1301 Constitution Avenue NW, Washington, DC 20004. Delivery verification signatures will be available only during regular business hours.

FOR FURTHER INFORMATION CONTACT: For questions about this proposed 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.* For information about the applicability of the new source performance standard (NSPS) to a particular entity, contact Ms. Marcia Mia, Office of Enforcement and Compliance Assurance, U.S. Environmental Protection Agency, EPA WJC South Building (Mail Code 2227A), 1200 Pennsylvania Avenue NW, Washington DC 20460; telephone number: (202) 564–7042; and email address: *mia.marcia@epa.gov.*

SUPPLEMENTARY INFORMATION:

Docket. The EPA has established a docket for this rulemaking under Docket ID No. EPA–HQ–OAR–2017–0483. All documents in the docket are listed in *Regulations.gov.* Although listed, some information is not publicly available, *e.g.,* CBI or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the internet and will be publicly available only in hard copy. Publicly available docket materials are available either electronically in *Regulations.gov* or in hard copy at the EPA Docket Center, Room 3334, EPA WJC West Building, 1301 Constitution Avenue NW, Washington, DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the EPA Docket Center is (202) 566–1742.

Instructions. Direct your comments to Docket ID No. EPA–HQ–OAR–2017–0483. The EPA's policy is that all comments received will be included in the public docket without change and may be made available online at *https://www.regulations.gov,* including any personal information provided, unless the comment includes information claimed to be CBI or other information whose disclosure is restricted by statute. Do not submit information that you consider to be CBI or otherwise protected through *https://www.regulations.gov* or email. This type of information should be submitted by mail as discussed in the **SUPPLEMENTARY INFORMATION** section of this preamble.

The EPA may publish any comment received to its public docket. Multimedia submissions (audio, video, etc.) must be accompanied by a written comment. The written comment is considered the official comment and should include discussion of all points you wish to make. The EPA will generally not consider comments or comment contents located outside of the primary submission (*i.e.,* on the Web, cloud, or other file sharing system). For additional submission methods, the full EPA public comment policy, information about CBI or multimedia submissions, and general guidance on making effective comments, please visit *https://www2.epa.gov/dockets/commenting-epa-dockets.*

The *https://www.regulations.gov* website allows you to submit your comments anonymously, which means the EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an email comment directly to the EPA without going through *https://www.regulations.gov,* your email address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the internet. If you submit an electronic comment, the EPA recommends that you include your name and other contact information in the body of your comment and with any digital storage media you submit. If the EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, the EPA may not be able to consider your comment. Electronic files should not include special characters or any form of encryption and be free of any defects or viruses. For additional information about the EPA's public docket, visit the EPA Docket Center homepage at *https://www.epa.gov/dockets.*

Submitting CBI. Do not submit information containing CBI to the EPA through *https://www.regulations.gov* or email. Clearly mark the part or all of the information that you claim to be CBI. For CBI information on any digital storage media that you mail to the EPA, mark the outside of the digital storage media as CBI and then identify electronically within the digital storage media the specific information that is claimed as CBI. In addition to one complete version of the comments that includes information claimed as CBI, you must submit a copy of the comments that does not contain the information claimed as CBI directly to the public docket through the procedures outlined in *Instructions* above. If you submit any digital storage media that does not contain CBI, mark the outside of the digital storage media clearly that it does not contain CBI. Information not marked as CBI will be included in the public docket and the EPA's electronic public docket without prior notice. Information marked as CBI will not be disclosed except in accordance with procedures set forth in 40 CFR part 2. Send or deliver information identified as CBI only to the following address: OAQPS Document Control Officer (C404–02), OAQPS, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711, Attention Docket ID No. EPA–HQ–OAR–2017–0483.

Preamble Acronyms and Abbreviations. A number of acronyms and abbreviations 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
AVO Auditory, Visual, and Olfactory
BOE Barrels of Oil Equivalent
BSER Best System of Emissions Reduction
CAA Clean Air Act
CBI Confidential Business Information
CFR Code of Federal Regulations
CO2 Eq. Carbon dioxide equivalent
CVS Closed Vent System
EPA Environmental Protection Agency
FTE Full Time Equivalent
GHG Greenhouse Gases
GHGRP Greenhouse Gas Reporting Program
LDAR Leak Detection and Repair
NDE No Detectable Emissions
NEMS National Energy Modeling System
NSPS New Source Performance Standards
NTTAA National Technology Transfer and Advancement Act
OGI Optical Gas Imaging
OMB Office of Management and Budget
PE Professional Engineer
PRA Paperwork Reduction Act
PRV Pressure Relief Valve
REC Reduced Emissions Completion
RFA Regulatory Flexibility Act
RIA Regulatory Impact Analysis
TSD Technical Support Document
UMRA Unfunded Mandates Reform Act
VOC Volatile Organic Compounds
VRU Vapor Recovery Unit

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

I. Executive Summary

A. Purpose of the Regulatory Action

The purpose of this action is to propose amendments to the NSPS for the oil and natural gas source category based on our 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 OOOOa"). The 2016 NSPS OOOOa established NSPS for emissions of greenhouse gases (GHG), in the form of limitations on methane, and volatile organic compounds (VOC) from the oil and natural gas sector.[1] Following promulgation of the final rule, the Administrator received petitions for reconsideration of several provisions of the 2016 NSPS OOOOa.[2] The EPA granted reconsideration on three issues: (1) Fugitive emissions requirements, (2) well site pneumatic pump standards, and (3) the requirements for certification of closed vent systems by a professional engineer based on specific objections to these requirements. This action addresses those specific issues raised for reconsideration, and addresses other implementation issues and technical corrections identified after promulgation of the rule.

B. Summary of Major Provisions of the Regulatory Action

The EPA proposes amendments and clarifications related to specific issues for which reconsideration was granted: Fugitive emissions requirements, well site pneumatic pump standards, the requirements for certification of closed vent systems, and the alternative means of emissions limitations (AMEL) provisions. The EPA also proposes additional amendments to clarify and streamline implementation of the rule. These proposed clarifications include 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 (maximum average daily throughput), and general clarifications (certifying official and recordkeeping

[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.

and reporting). Lastly, in addition to the proposed revisions addressing reconsideration and implementation issues, the EPA is proposing technical corrections of inadvertent errors in the final rule.

Fugitive emissions requirements. The EPA is proposing several revisions to the requirements for the collection of fugitive emissions components located at well sites and the collection of fugitive emissions components located at compressor stations. First, the EPA is proposing to revise the monitoring frequencies: (1) Annual monitoring for non-low production well sites, (2) biennial (once every other year) monitoring for low production well sites, (3) co-proposing semiannual and annual monitoring for compressor stations, and (4) annual monitoring for compressor stations located on the Alaska North Slope. Additionally, the EPA is proposing that monitoring would no longer be required when all major production and processing equipment is removed from a well site such that it becomes a wellhead only well site. Consistent with the amendments promulgated on March 12, 2018,[3] the EPA is proposing separate initial monitoring requirements for compressor stations located on the Alaska North Slope. These compressor stations would be required to conduct initial monitoring within 6 months or by June 30, whichever is later, for compressor stations that startup between September and March or within 60 days for compressor stations that startup between April and August.

In addition to the proposed amendments related to the monitoring frequencies, the EPA is proposing various amendments to other requirements in the fugitive emissions monitoring program. The EPA is proposing to clarify that a modification has occurred at a well site that is a separate tank battery when a well that sends production to that tank battery has been modified. Given the proposed changes to monitoring frequencies, the EPA is proposing to remove the existing low temperature waiver for compressor stations.

Several definitions related to fugitive emissions are included in this proposal. First, the EPA is proposing to add definitions for the terms ''first attempt at repair'' and ''repaired'' specific to the fugitive emissions requirements. Further, the EPA is proposing that a first attempt at repair must be completed within 30 days of identifying a component with fugitive emissions, with final repair completed within 60 days. The proposed definition of ''repaired'' includes a requirement to verify the fugitive emissions are repaired before the repair is completed. We are also proposing revisions to the definition of ''well site'' to include exclusions for third party equipment located downstream of the custody meter assembly and saltwater disposal facilities. Finally, we are proposing specific changes to the fugitive emissions monitoring plan, including alternative requirements to the site plan and observation path.

Pneumatic pumps. The EPA is proposing to expand the technical infeasibility provision to all well sites by eliminating the categorical distinction between greenfield sites and non-greenfield sites (and the categorical restriction of the technical infeasibility provision to existing sites) for the pneumatic pump requirements. The proposal would avoid the potential of requiring a greenfield site to control the pneumatic pump emissions should it be technically infeasible to do so, while having no impact on the compliance obligations of other greenfield sites that do not have this issue.

Professional Engineer (PE) certifications. The EPA is proposing to amend the certification requirements for closed vent system (CVS) design and technical infeasibility for pneumatic pumps by allowing certification by either a PE or an in-house engineer with expertise on the design and operation of the CVS or pneumatic pump.

Alternative means of emission limitation (AMEL). The 2016 NSPS OOOOa contains provisions for owners and operators to request an AMEL for specific work practice standards in the rule, covering well completions, reciprocating compressors, and the collection of fugitive emissions components located at well sites and compressor stations. An owner or operator can request an AMEL by submitting data that demonstrate the alternative will achieve at least equivalent emission reductions as the requirements in the rule, among other requirements such as initial and on-going compliance monitoring. The specific requirements for this request are outlined in 40 CFR 60.5398a. For the 2016 NSPS OOOOa, these alternatives could be based on emerging technologies (*e.g.,* for fugitive emissions, technologies other than OGI or Method 21) or requirements under state or local programs. The EPA is proposing to amend the language in 40 CFR 60.5398a for incorporation of emerging technologies, and to add a separate section at 40 CFR 60.5399a to take into account existing state programs.

Location of a Separator During Flowback. The 2016 NSPS OOOOa requires the owner or operator to have a separator onsite during the entirety of the flowback period. The EPA is proposing to amend 40 CFR 60.5375a(a)(1)(iii) to clarify that the separator may be located at the well site or near to the well site so that it is able to commence separation flowback, as required by the rule. This proposed revision is being made to alleviate the potential interpretation that the separator must be located on the well site, which was not the intent of the rule.

Screenouts and Coil Tubing Cleanouts. Petitioners requested clarification as to whether screenouts and coil tubing cleanouts are regulated as part of flowback. Based on the EPA's reassessment of this issue, the EPA is correcting previous guidance on this issue to acknowledge that screenouts and coil tubing cleanouts are not a part of flowback; rather, they are functional processes that allow for flowback to begin. To clarify this point, the EPA is proposing to revise the definition of flowback to expressly exclude these processes to avoid any future confusion. In addition, the EPA is proposing definitions for these processes (*i.e.,* plug drill-outs, flowback routed through permanent separators).

Capital Expenditure. The EPA is proposing to correct the definition of ''capital expenditure'' promulgated at 40 CFR 60.5430a by replacing the reference to the year 2011 with the year 2015 in the formula in paragraph (2) of the definition. The promulgated definition is relevant to the equipment leaks standards for onshore natural gas processing plants that were originally promulgated in 1985 in 40 CFR part 60, subpart KKK, updated in 2012 in 40 CFR part 60, subpart OOOO, and carried over in 2016 in 40 CFR part 60, subpart OOOOa. The EPA is, therefore, amending the definition to address an inadvertent mathematical issue for affected facilities constructed in 2015 while leaving the calculation method intact for other affected facilities.

Maximum Average Daily Throughput. Pursuant to 40 CFR 60.5365a(e), owners and operators must calculate potential emissions from storage vessels in order to determine if control requirements apply. This calculation is based on the ''maximum average daily throughput''. This value was intended to represent the maximum of the average daily production rates in the first 30-day period to each individual storage vessel. In order to address petitioner requests for clarification, the EPA is proposing to further clarify in this notice when and

[3] 83 FR 10628.

how daily production may be averaged in determining daily throughput. The EPA is proposing to revise the definition to clarify that the maximum average daily throughput refers to the maximum average daily throughput for an individual storage vessel over the days that production is routed to that storage vessel during the 30-day evaluation period.

Certifying Official. The EPA is proposing to amend this definition to remove the reference to permits to clarify that the requirements of the NSPS are not associated with a permitting program.

Onshore Natural Gas Processing Plant Monitoring Exemption. The EPA is proposing to amend the requirements for equipment leaks at onshore natural gas processing plants. Specifically, the EPA is proposing to include an exemption from monitoring for certain equipment that an owner or operator designates as being in VOC service less than 300 hr/yr.

Recordkeeping and Reporting Requirements. The EPA is proposing to streamline certain reporting and recordkeeping requirements to reduce burden on the regulated industry. The proposed changes can be seen in section 60.5420a.

C. Costs and Benefits

The EPA has projected the cost savings, emissions changes, and forgone benefits that may result from this proposed action. The projected cost savings and forgone benefits are presented in the RIA supporting this proposal. The RIA focuses on the elements of the proposal—the provisions related to fugitive emissions requirements and certification by a professional engineer—that are likely to result in quantifiable cost or emissions changes compared to a baseline that includes the 2016 NSPS OOOOa requirements.

The effects of this proposed regulation are estimated for all sources that are projected to change compliance activities under this proposed rule for the analysis years 2019 through 2025. The RIA also presents the present value (PV) and equivalent annualized value (EAV) of costs, benefits and net benefits of the proposed action in 2016 dollars. Cost savings include the forgone value associated with the decrease in natural gas recovery as a result of this proposed action.

A summary of the key results of the co-proposed option under semiannual monitoring at compressor stations presented as shown in the RIA can be found 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 co-proposed option. In the following tables, the EPA refers to the cost savings as the ''benefits'' of this proposed action and the forgone benefits as the ''costs'' of this proposed action. The net benefits are the benefits (cost savings) minus the costs (forgone benefits).[4]

TABLE 1—COST SAVINGS, FORGONE BENEFITS AND INCREASE IN EMISSIONS OF THE CO-PROPOSED OPTION 3 (SEMIANNUAL MONITORING) COMPARED TO THE 2018 BASELINE, 2019 THROUGH 2025

[Millions 2016$]

	7%		3%	
	Present value	Equivalent annualized value	Present value	Equivalent annualized value
Benefits (Total Cost Savings)	$380	$66	$484	$75
Cost Savings	*429*	*74*	*546*	*85*
Forgone Value of Product Recovery	*48*	*8.4*	*62*	*9.6*
Costs (Forgone Domestic Climate Benefits)[1]	13.5	2.3	54	8.3
Net Benefits[2]	367	64	431	67
Emissions	Total Change			
Methane (short tons)	380,000			
VOC	100,000			
HAP	3,800			
Methane (million metric tons CO2E)	8.5			

[1] The forgone benefits estimates are calculated using estimates of the social cost of methane (SC–CH_4). SC–CH_4 values represent only a partial accounting of domestic climate impacts from methane emissions. See section 3.3 of the RIA for more discussion.

[2] Estimates may not sum due to independent rounding.

The estimated costs (forgone benefits) include the monetized climate effects of the projected increase in methane emissions under the proposal. The EPA also expects 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, $PM_{2.5}$, and HAP, data limitations prevent the EPA from quantifying forgone VOC-related health benefits.

Compared to the estimated cost savings of the co-proposed option under semiannual fugitive emissions monitoring at compressor stations, the co-proposed option assuming annual monitoring results in greater cost savings, as well as greater total emissions. Assuming a 7 percent discount rate, and including the forgone value of product recovery, the present value of the total cost savings from 2019 through 2025 are about $43 million greater under the co-proposed option assuming annual monitoring than under the co-proposed option assuming semiannual monitoring. This is associated with an increase in the equivalent annualized value of total cost savings of about $7.5 million per year in comparison to the co-proposed option under semiannual monitoring.

Decreasing fugitive emissions monitoring frequency at compressor stations from semiannual to annual also

[4] For information on the cost savings and forgone emission reductions associated with the co-proposed option assuming annual fugitives monitoring at compressor stations, see section 2 of the RIA.

results in a greater increase in total emissions. Over 2019 through 2025, the increase in fugitive emissions under the co-proposed option assuming annual monitoring are about 100,000 short tons greater for methane, 24,000 tons greater for VOC, and 890 tons greater for HAP than those under the co-proposed option assuming semiannual fugitive emissions monitoring. A summary of the cost savings and forgone emission reductions associated with the co-proposed option of annual fugitive emissions monitoring at compressor stations is located in section 2.5.2 of the RIA.

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. This table lists the types of entities that the EPA is now aware could potentially be affected by this action. Other types of entities not listed in the table could also be regulated. To determine whether your entity is regulated 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. What should I consider as I prepare my comments to the EPA?

We seek comment only on the aspects of the proposed NSPS for the oil and natural gas sector specifically identified in this notice. We are not opening for reconsideration any other provisions of the NSPS at this time.

Do not submit information containing CBI to the EPA through *https://www.regulations.gov* or email. Send or deliver information identified as CBI only to the following address: OAQPS Document Control Officer (C404–02), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711, Attention: Docket ID Number EPA–HQ–OAR–2017–0483. Clearly mark the part or all of the information that you claim to be CBI. For CBI information in a disk or CD–ROM that you mail to the EPA, mark the outside of the disk or CD–ROM as CBI and then identify electronically within the disk or CD–ROM the specific information that is claimed as CBI. In addition to one complete version of the comment that includes information claimed as CBI, a copy of the comment that does not contain the information claimed as CBI must be submitted for inclusion in the public docket. Information so marked will not be disclosed except in accordance with procedures set forth in 40 CFR part 2.

C. How do I obtain a copy of this document and other related information?

In addition to being available in the docket, an electronic copy of the proposed action is available on the internet. Following signature by the Administrator, the EPA will post a copy of this proposed action at *https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry.* Additional information is also available at the same website.

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 Sources; Final Rule,'' at 81 FR 35824 (''2016 NSPS OOOOa''). The 2016 NSPS OOOOa established NSPS for greenhouse gas and volatile organic compound (VOC) emissions from the oil and natural gas sector. For further information on the 2016 NSPS 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 OOOOa. Copies of the petitions are provided in rulemaking docket EPA–HQ–OAR–2017–0483. A number of states and industry associations sought judicial review of the rule, and the litigation is currently being held in abeyance.

In a letter to petitioners dated April 18, 2017, the EPA granted reconsideration of the fugitive emissions requirements at well sites and compressor stations.[5] In a subsequent notice, the EPA granted reconsideration of two additional issues: Well site pneumatic pump standards and the requirements for certification of closed vent systems (CVS) by a professional engineer.[6] This action proposes amendments and clarifications to address these issues, and grants reconsideration and proposes amendments to address several additional reconsideration issues, detailed in Section VII below. In addition, since the publication of the 2016 NSPS OOOOa, the EPA has received numerous questions relative to the implementation of the 2016 NSPS OOOOa requirements. This action also addresses these broad implementation issues that have been brought to the EPA's attention. The EPA is addressing these issues at the same time to provide clarity and certainty for the public and the regulated community with regard to these requirements.

IV. Legal Authority

This action, which proposes certain amendments to the 2016 NSPS OOOOa, is based on the same legal authorities as those for the promulgation of that rule. The EPA promulgated the 2016 NSPS 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

[5] See Docket ID No. EPA–HQ–OAR–2010–0505–7730.

[6] 82 FR 25730.

procedures in section 307(d) of the CAA. Section 111(b)(1)(B) requires the EPA to issue ''standards of performance'' for new sources in a category listed by the Administrator based on a finding that this category of stationary sources causes or contributes 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.'' This definition makes clear that the standard of performance must be based on controls that constitute ''the best system of emission reduction . . . adequately demonstrated.'' The standard that the EPA develops, based on the best system of emission reduction (BSER), is commonly a numerical emissions 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 reflects the best technological system of continuous emission reduction, if it is not feasible to prescribe or enforce an emissions standard. This action includes proposed 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)(A). 81 FR 35829.

The proposed amendments in this notice result from the EPA's reconsideration of various aspects of the 2016 NSPS 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 Television 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).

V. The Proposed Action

In this action, we are proposing amendments and clarifications on the following set of issues as a result of reconsideration: (1) Pneumatic pump requirements; (2) fugitive emissions requirements at well sites and compressor stations; (3) professional engineering certification for CVS design and pneumatic pump technical infeasibility; and (4) alternative means of emissions limitations. In addition, we are proposing amendments to a number of other aspects of 2016 NSPS OOOOa, including well completion requirements and requirements at onshore natural gas processing plants. This action also addresses broad implementation issues that have been brought to the EPA's attention. Finally, we are proposing to correct technical errors that were inadvertently included in the final rule.

This document is limited to the specific issues identified in this notice. We will not respond to any comments addressing any other provisions of the 2016 NSPS OOOOa.

VI. Discussion of Provisions Subject to Reconsideration

As summarized above, the EPA is proposing to address a number of issues that have been raised by different stakeholders through several administrative petitions for reconsideration of the 2016 NSPS OOOOa. The following sections present the issues raised by the petitioners that the EPA is addressing in this action and how the EPA proposes to resolve the issues.

A. Pneumatic Pumps

The 2016 NSPS OOOOa includes a technical infeasibility provision from the well site pneumatic pump requirements for circumstances such as insufficient pressure or control device capacity. 81 FR 35850. This provision was categorically unavailable for pneumatic pumps at greenfield sites (defined as a site, other than a natural gas processing plant, which is entirely new construction). *Id.* Petitioners stated that the term greenfield site was inadequately defined. For example, one petitioner questioned whether the term ''new'' as used in this definition is synonymous to how that term is defined in section 111 of the CAA. Additional questions included whether a greenfield remains forever a greenfield, considering that site designs may change by the time that a new control or pump is installed (which may be years later). Petitioners also objected to the EPA's assumption that the technical infeasibility encountered at existing well sites can be addressed when ''new'' sites are developed.

We previously concluded that circumstances, such as insufficient pressure or control device capacity, 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 and therefore new sites were categorically ineligible for the technical feasibility provision. 81 FR 35850. However, petitioners have raised the concern that even at a greenfield site, there may be unique process or control design requirements that may not be compatible with controlling pneumatic pump emissions. Petitioners contend that such circumstances include the following:

- A new site design may require only a high-pressure flare to control emergency and maintenance blowdowns, and it is not feasible for a low pressure pneumatic pump discharge to be routed to such a flare; and
- A new site design may require only a small boiler or process heater, but such boiler or process heater could be insufficient to control pneumatic pumps emissions and routing pneumatic pump emissions to the boiler or process heater could result in safety trips and burner flame instability.

The EPA solicits comment on whether the scenarios described above present circumstances where control of a pneumatic pump may be technically infeasible despite the site being newly designed and constructed, as well as other examples of technical infeasibility for a greenfield site. While the additional cost in the design and construction of a new site for selecting a control device that can control additional pneumatic pump emissions (*e.g.,* selecting a flare or slightly larger boiler that can accommodate such flows) in many cases will not be high, the scenarios raised in petitions for reconsideration suggest that there might be cases of technical infeasibility at a greenfield site despite design and construction choices. We are therefore proposing to expand the technical infeasibility provision to all well sites by eliminating the categorical distinction between greenfield sites and non-greenfield sites (and the categorical restriction of the technical infeasibility provision to existing sites) for the pneumatic pump requirements. The proposal would avoid the potential of requiring a greenfield site to control the pneumatic pump emissions should it be technically infeasible to do so, while having no impact on the compliance obligations of other greenfield sites that do not have this issue. We solicit comment on this proposal. In addition, we solicit comment on site and control configurations that could present technical infeasibility scenarios at a new construction site. We also solicit comment on cost information related to the additional costs related to selecting a control that can accommodate pneumatic pump emissions in addition to the control's primary purpose at a new construction site.

B. Fugitive Emissions From Well Sites and Compressor Stations

1. Monitoring Frequency

Monitoring Frequency for Well Sites. The 2016 NSPS OOOOa requires initial monitoring within 60 days of the startup of production and subsequent semiannual monitoring of the collection of fugitive emissions components located at all well sites. We received petitions requesting changes to several aspects of fugitive monitoring frequencies to provide: (1) A pathway to less frequent monitoring, (2) an exemption for low production well sites, and (3) an exemption for well sites located on the Alaskan North Slope. As discussed in detail in the following subsections, the EPA is proposing the following amendments to the fugitive emissions monitoring frequency for the collection of fugitive emissions components located at well sites:

- Annual monitoring would be required at 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 averaged over the first 30 days of production (''non-low production well sites'');
- Biennial monitoring (once every other year) would be required for well sites with average combined oil and natural gas production for the wells at the site less than 15 boe per day averaged over the first 30 days of production (''low production well sites''); 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.

Non-low Production Well Sites. The 2016 NSPS OOOOa requires initial and semiannual fugitive emissions monitoring using optical gas imaging (OGI) for the collection of fugitive emissions components located at well sites. In the 2016 NSPS OOOOa preamble, the EPA stated that ''both semiannual and annual monitoring remain cost-effective for reducing GHG (in the form of methane) and VOC emissions.'' 81 FR 35855. Several petitioners requested that the EPA reconsider the frequency of monitoring,[7] with one petitioner asserting that the EPA's cost-effectiveness analysis is not accurate and should be revised.[8] In response, the EPA has reviewed the data provided by the petitioner, as well as other data that have become available since promulgation of the 2016 NSPS OOOOa. Based on this review, we have updated our model plant analysis. Although under the updated analysis, semiannual monitoring may appear to be cost-effective, we have identified several areas of our analysis that indicate we may have overestimated the emission reductions and, therefore, the cost effectiveness, due to gaps in available data and factors that may bias the analysis towards overestimation of reductions. Therefore, the semiannual monitoring may not be as cost-effective as presented, and the EPA is proposing to revise the monitoring frequency to require annual fugitive emissions monitoring at non-low production well sites. Provided below is a detailed discussion of (1) how we revised the model plant analysis based on our review of the data; and (2) areas of our analysis that indicate we may have overestimated the emission reductions and in turn the cost effectiveness of the monitoring frequencies analyzed.

First, the EPA reviewed the available information and determined several updates were necessary to the non-low production well site model plants. As described in the TSD, the EPA evaluated the cost-effectiveness of the fugitive emissions monitoring program using model plants that represent average equipment and fugitive emissions component counts per well site.[9] We updated the model plants based on updates in the Greenhouse Gas Inventory (GHGI) program for major equipment counts at well sites. Specifically, the number of meters/piping decreased from 3 to 2 for the gas well site and oil with associated gas well site model plants. No changes were made to the oil well site model plant as a result of updates in the GHGI. The petitioner provided information that included counts for major production and processing equipment located at well sites.[10] For example, the data included the count of separators per well site and demonstrated that, on average, there are 3 separators per natural gas well site and oil well site. In comparison, the EPA model plants include 2 separators per natural gas well site and 1 separator per oil well site. While similar differences were observed for other types of major production and processing equipment, we maintained the estimates derived from the GHGI because the data included in the GHGI is the most up-to-date information available and the petitioner was not able to provide information on when the fugitive emissions monitoring occurred at the well sites presented in their data set.

In addition to updates made based on updates to the GHGI, we also added one controlled storage vessel per model plant and an emissions factor for pressure relief devices (PRDs), such as thief hatches and pressure relief valves (PRVs) from these controlled storage vessels because controlled storage vessels that are not affected facilities subject to the requirements in 40 CFR 60.5395a are considered fugitive emissions components. In evaluating the quantity of fugitive emissions from storage vessels, we considered data indicating that the frequency of fugitive emissions from controlled storage vessels may be much higher than that for other fugitive emissions components.[11] For purposes of the model plant, we are adding one controlled storage vessel with one PRD. We recognize that many well sites may have more controlled storage vessels, suggesting that we should add more than one controlled storage vessel to the model plant, while other well sites may not have any controlled storage vessels that are subject to fugitive emissions monitoring. The data provided by the petitioner[12] did not include the number of storage vessels at natural gas well sites, but included an estimated average of 7 storage vessels per oil well site. However, the data was not provided in a form sufficient to indicate whether these storage vessels are controlled or subject to fugitive emissions monitoring. Therefore, we did not incorporate any information from the petitioner related to storage vessel counts at well sites. We are soliciting comment on our assumption of one controlled storage vessel per well site subject to fugitive emissions requirements and data to further refine the model plant with

[7] See Docket ID Nos. EPA–HQ–OAR–2010–0505–7682, EPA–HQ–OAR–2010–0505–7685 and EPA–HQ–OAR–2010–0505–7686.

[8] See Docket ID No. EPA–HQ–OAR–2010–0505–7682.

[9] See TSD for additional information.

[10] See memorandum *EPA Analysis of Well Site Fugitive Emissions Monitoring Data Provided by API* located at Docket ID No. EPA–HQ–OAR–2017–0483. April 17, 2018.

[11] See the TSD for additional information on the fugitive emissions from storage vessels.

[12] See memorandum *EPA Analysis of Well Site Fugitive Emissions Monitoring Data Provided by API* located at Docket ID No. EPA–HQ–OAR–2017–0483. April 17, 2018.

regards to controlled storage vessel fugitive emissions.

The emissions factor used for PRDs on controlled storage vessels was derived from a study that conducted aerial surveys for emissions at oil and gas production sites located in seven basins across the United States.[13] We did not update the average emissions factors for other fugitive emissions components based on information in this study because the study stated that emissions from individual components, such as valves, could not be identified during the surveys. In this study, helicopter-based OGI monitoring was performed at 8,220 well sites. A total of 494 fugitive emission sources were identified at 327 sites, averaging approximately 1.5 fugitive sources per site. Fugitive emissions [14] from storage vessels accounted for 92 percent of the total fugitive sources, with 198 fugitive sources associated with storage vessel PRVs and 257 fugitive sources associated with thief hatches, though it was unclear from the study if all of these storage vessels were equipped with a CVS that routes emissions to a control device. The estimated detection limit for the OGI instrument observed by this study was 1 gram per second (g/s) for heavier hydrocarbons and 3 g/s for methane.[15] Based on this information, we used the 1 g/s estimated emission rate in combination with the frequency of storage vessel emissions identified in the study to estimate emissions from thief hatches for purposes of the model plants. However, we acknowledge that the emissions are likely underestimated when using this information because small or medium sized emissions would not be visible during an aerial OGI survey. Additional information about the model plants and analysis is included in the Background Technical Support Document (TSD) located at Docket ID No. EPA–HQ–OAR–2017–0483.

Baseline emissions (uncontrolled) for the other fugitive emissions components were estimated using average emissions factors for oil and gas production operations, found in Table 2–4 of the *Protocol for Equipment Leak Emission Estimates* (1995 Protocol).[16] These average emissions factors are used when screening data are not available, as is the case when OGI is used as the monitoring instrument,[17] and provide an average emission rate for the collection of fugitive emissions components at the site. For example, the average emissions factors can be used to estimate emissions from the collection of all valves at the site, instead of needing to estimate emissions from each individual valve and averaging the emissions across the collection of valves. The petitioner presented updated emissions factors for these fugitive emissions components.[18] The petitioner attempted to create new average emissions factors by using the newly presented 0.4 percent for identified fugitive emissions and scaling the average emissions factors documented in the 1995 Protocol. However, in creating these new average emissions factors, the petitioner used correlation equations in the 1995 Protocol. These correlation equations were derived from leak studies using Method 21 of Appendix A–7 to Part 60 (''Method 21'') and are based on specific leak definitions when using Method 21. The correlation equations do not apply to monitoring using OGI, as it is not possible to correlate OGI detection capabilities with a Method 21 instrument reading provided in parts per million (ppm). Correlation equations for OGI do not currently exist and would be difficult to develop because OGI either sees fugitive emissions or it does not; there is no emissions scale as there is with Method 21. As such, at best, only average factors for visualized emissions and no visualized emissions would be possible (similar to the ''leak'' and ''no leak'' factors in the 1995 Protocol specific to Method 21). In order to develop such factors, an extensive dataset of OGI data and bagging studies, similar to the studies used to develop the factors presented in the 1995 Protocol would be needed. Therefore, the approach of scaling emissions factors as presented by the petitioner for the non-storage vessel PRD fugitive emissions components does not adequately address the differences in emissions correlations when using Method 21 and OGI, and therefore we have not evaluated the cost of control using the scaled factors presented by the petitioner. Additional information on our evaluation of the scaled emissions factors is included in the memorandum *EPA Analysis of Well Site Fugitive Emissions Monitoring Data Provided by API,* located at Docket ID No. EPA–HQ–OAR–2017–0483. Thus, we continue to use the average emissions factors in the 1995 Protocol to calculate emissions in the model plants for the fugitive emissions components, excluding controlled storage vessel PRDs. We are soliciting comment on the use of the average emissions factors and additional information or alternative methodologies that should be considered to refine our estimates of fugitive emissions.

While updating the model plants, 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. As described in detail below, the EPA acknowledges that emission reductions may have been overestimated, even in our updated model plants.

First, several stakeholders have raised concerns regarding the percent emission reductions (*i.e.,* control effectiveness) of OGI monitoring at the various monitoring frequencies. In the analysis described in the TSD, the EPA estimates emission reductions of 30 percent for biennial monitoring, 40 percent for annual monitoring, 45 percent for stepped monitoring, 60 percent for semiannual monitoring, and 80 percent for quarterly monitoring.[19] The estimates for annual, semiannual, and quarterly monitoring frequencies are the same as those during used for the 2016 NSPS OOOOa. Stakeholders have raised specific concerns regarding the control effectiveness values for semiannual and quarterly monitoring. One stakeholder asserts that the ''EPA's leak emission reduction estimates are based on a LDAR control efficiency model with high uncertainty and biased by flawed and unrepresentative data and assumptions.'' [20] Specific concerns

[13] Lyon, David R., et al., *Aerial Surveys of Elevated Hydrocarbon Emissions from Oil and Gas Production Sites.* Environmental Science and Technology 2016, 50, 4877–4886.

[14] It was difficult for the Lyon, David R., et al., study to attribute emissions from storage vessels to specific malfunctions or normal operations. The study predicted liquid unloading events and stuck open separator dump valves would contribute less than 0.1% of the emissions detected for each event. The other 99.8% of the storage vessel emissions were not characterized by the study. See *Id.* at pages 4882–4883.

[15] *Id.*

[16] U.S. Environmental Protection Agency, Protocol for Equipment Leak Emission Estimates. Table 2–4. November 1995 (EPA–453/R–95–017).

[17] OGI instruments that are currently widely available provide a qualitative indication of emissions and do not provide an indication of the concentration levels of fugitive emissions. However, we recognize that quantitative OGI is a new technological development that may allow estimations of mass emission rates in the future.

[18] See memorandum *EPA Analysis of Well Site Fugitive Emissions Monitoring Data Provided by API* located at Docket ID No. EPA–HQ–OAR–2017–0483. April 17, 2018.

[19] See TSD for additional information related to OGI control effectiveness.

[20] See ''Methane Emissions from Natural Gas Transmission and Storage Facilities: Review of

Continued

raised by this stakeholder include the comparison of OGI control effectiveness to Method 21 control effectiveness. The stakeholder noted that the EPA based the Method 21 control effectiveness evaluation on information from the Synthetic Organic Chemical Manufacturing Industry (SOCMI) which the stakeholder suggests overestimates fugitive emissions because this data is not representative of the oil and natural gas sector. We are soliciting comment and information that would support a revision of the evaluation of the Method 21 alternative that is more representative of the oil and natural gas industry.

This stakeholder also raised concerns that the estimated control efficiency of 80 percent for quarterly monitoring is too low, suggesting 90 percent would be more appropriate for quarterly monitoring and 80 percent for annual monitoring.[21] The stakeholder references a report by the Canadian Association of Petroleum Producers (CAPP) that estimated a net-weighted decrease of component-specific emissions factors following the implementation of best management practices, also published by CAPP.[22 23] The EPA has reviewed this report from CAPP and the associated best management practices to determine if updates to our estimated control efficiencies for OGI are appropriate. In our analysis [24] of the information presented by CAPP, we are unable to conclude that annual monitoring with OGI will achieve 80 percent emission reductions because there is no information regarding the type of detection method used or repair requirement related to the facilities that provided data for the CAPP emissions factor update study. The related Best Management Practices document provides some information about the recommended frequency of monitoring; [25] however, the information provided for the CAPP study does not specify what monitoring frequencies were implemented at the facilities. Therefore, the TSD continues to use 80 percent as the best estimated control effectiveness for quarterly monitoring.[26] While the EPA's estimated emission reductions are based on the best currently available information, there are considerable uncertainties associated with that information and the consequent reductions, and the EPA is aware there may be studies that may provide additional analysis on the effectiveness of OGI monitoring that can further refine our estimates. The EPA is requesting information on any analyses performed on the emission reductions achieved with OGI monitoring at different monitoring frequencies and the data underlying these analyses, including information on how the data was gathered, what the data represents, and how the analysis was performed.

Second, 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. The percentage of components found with fugitive emissions is similar to the occurrence rate (*i.e.,* the percentage of components not ''leaking'' that start to ''leak'' between monitoring cycles) of leak detection and repair (LDAR) programs. Appendix G of the 1995 Protocol describes how to calculate the occurrence rate.[27] When we have evaluated the use of Method 21 as an alternative for OGI in the fugitive emissions requirements of the 2016 NSPS OOOOa, we assumed occurrence rates that decrease with increasing monitoring frequencies, consistent with the 1995 Protocol. However, when evaluating the use of OGI, we assumed a constant percent of fugitive emissions components will be identified with fugitive emissions at each monitoring event, regardless of the number of monitoring events each year, which is counter to the 1995 Protocol and our evaluation of the Method 21 alternative. That is, the model plant analysis assumes that the same number of components will be identified with fugitive emissions during each monitoring event, regardless of how frequently monitoring occurs. Specifically, we currently assume that 4 components will have fugitive emissions during a single annual period if monitored annually, while 8 components will have fugitive emissions during a single annual period if monitored semiannually. While there is uncertainty regarding the number of components identified with fugitive emissions, as described below, the use of a single percentage for all monitoring frequencies may overestimate the number of fugitive emissions identified during more frequent monitoring events, such as semiannual monitoring. We are soliciting information to evaluate how the percentage of fugitive emissions identified changes with frequency to revise the model plant analysis.

Finally, in addition to the uncertainty described above regarding the percentage of fugitive emissions at the various monitoring frequencies, there is concern regarding the value that the EPA uses as an initial percentage in the model plant analysis. In the analysis for the 2016 NSPS OOOOa, we assumed a value of 1.18 percent based on information used in previous rulemakings for the SOCMI.[28] One petitioner provided data to demonstrate lower percentages of fugitive emissions than used in our analysis. One data set included information from well sites in Colorado and the Barnett Shale region of Texas.[29] This information included the number of components with fugitive emissions by component type, an estimate of the total number of each component type, and an estimated percentage of fugitive emissions components identified with fugitive emissions using both OGI and Method 21. Subsequent to the submission of their petition, this petitioner also provided additional data on the initial

Available Data on Leak Emission Estimates and Mitigation Using Leak Detection and Repair,'' prepared for INGAA by Innovative Environmental Solutions, Inc., June 8, 2018, located at Docket ID No. EPA–HQ–OAR–2017–0473.

[21] See memorandum *EPA Analysis of Fugitive Emissions Data Provided by INGAA* located at Docket ID No. EPA–HQ–OAR–2017–0483. August 21, 2018.

[22] See ''Update of Fugitive Equipment Leak Emission Factors'', prepared for Canadian Association of Petroleum Producers by Clearstone Engineering, Ltd., February 2014, located at Docket ID No. EPA–HQ–OAR–2017–0483.

[23] Canadian Association of Petroleum Producers, ''Best Management Practice. Management of Fugitive Emissions at Upstream Oil and Gas Facilities'', January 2007.

[24] See memorandum *EPA Analysis of Fugitive Emissions Data Provided by INGAA* located at Docket ID No. EPA–HQ–OAR–2017–0483. August 21, 2018.

[25] Canadian Association of Petroleum Producers, ''Best Management Practice. Management of Fugitive Emissions at Upstream Oil and Gas Facilities'', January 2007.

[26] See TSD for more information related to OGI control effectiveness.

[27] U.S. Environmental Protection Agency, Protocol for Equipment Leak Emission Estimates. Appendix G. November 1995 (EPA–453/R–95–017).

[28] The assumption of 1.18% leak rate for OGI monitoring was obtained from Table 5 of the Uniform Standards memorandum. The 1.18% value is the baseline leak frequency for valves in gas/vapor service. None of the other baseline frequencies in this table were used because the equipment is in liquid service (*e.g.,* pumps LL, valve LL, agitators LL). There is no information on the number of leaks located at uncontrolled facilities, only average percentages of the total number of components at a facility. Therefore, our methodology was to use the 1.18% leak frequency value from the Uniform Standards memorandum and apply that value to the total number of components at the oil and natural gas model plant. (Uniform Standards Memorandum to Jodi Howard, EPA/OAQPS from Cindy Hancy, RTI International, Analysis of Emission Reduction Techniques for Equipment Leaks, December 21, 2011. EPA–HQ–OAR–2002–0037–0180).

[29] See Docket ID No. EPA–HQ–OAR–2010–0505–7682.

fugitive emissions percentages for well sites located in 14 states.[30] While the letter from the petitioner stated that on average 0.4 percent of fugitive emissions components were identified with fugitive emissions, this percentage was based on the aggregation of fugitive emissions by dividing the total number of fugitive emissions components identified with fugitive emissions by the total estimated number of fugitive emissions components monitored within the entire dataset; therefore, the 0.4 percent does not represent the average percentage of fugitive emissions components found with fugitive emissions at individual well sites, which is the information needed to evaluate fugitive emissions requirements at an individual well site. The EPA, therefore, has evaluated the data provided to determine the average percentage of fugitive emissions components identified with fugitive emissions at the individual well site level, consistent with our model plant approach and the standards for fugitive emissions in the 2016 NSPS OOOOa. Based on the EPA's analysis of the petitioner's data, the data result in an average percentage of 0.54 percent or an average of 2 components per well site with fugitive emissions during the initial monitoring survey.[31] This contrasts with the EPA's estimate of 4 components per well site with fugitive emissions during the initial monitoring survey, or 1.18 percent, used in the 2016 NSPS OOOOa. Additional information on our evaluation of this data is included in the memorandum *EPA Analysis of Well Site Fugitive Emissions Monitoring Data Provided by API,* located at Docket ID No. EPA–HQ–OAR–2017–0483. Based on this information, we are concerned that 1.18 percent is too high and not representative of the oil and gas sector. However, as discussed in the memorandum, the EPA has insufficient information, based on what was provided by the petitioner, to determine if the information is representative of fugitive emissions monitoring consistent with the requirements of the 2016 NSPS OOOOa. Therefore, we have not incorporated a change in the percentage value used in the model plant analysis and are soliciting more information as described later in this subsection.

In summary, although the EPA has incorporated several updates into the model plant analysis, the three areas described above cause concern that our analysis may still overestimate emission reductions. Based on the model plant analysis, we estimated the cost of control for each of the monitoring frequencies to determine how the changes to the model plants would affect the determination of cost-effectiveness presented in the 2016 NSPS OOOOa, noting that the revised analysis, notwithstanding its incorporation of additional information, does not address the three areas of concern described above. We applied the two approaches used in the 2016 NSPS OOOOa (single and multipollutant approaches) [32] for evaluating cost-effectiveness of the semiannual and annual monitoring frequencies for the fugitive emissions program for reducing both methane and VOC emissions from non-low production well sites.[33] For purposes of this reconsideration, we examined the emission reductions and costs for the fugitive emissions monitoring requirements at non-low production well sites at semiannual, annual, and stepped (semiannual for 2 years followed by annual monitoring thereafter) monitoring frequencies. This stepped monitoring frequency was based on a suggestion from one petitioner that, at a minimum, the EPA should require semiannual monitoring at well sites for an initial period of 2 years followed by less frequent monitoring frequencies such as annual monitoring for sites that do not have a significant number of ''leaking'' [34] components.[35] While we have not established what would constitute an insignificant number of leaking components and the period of time before that number is reached, we have historically recognized that initial percentages of leaks are generally higher than subsequent leak percentages for the non-storage vessel PRD fugitive emissions components.[36] As a fugitive emissions program is implemented, leak percentages decline until they reach a ''steady state.'' As illustrated in Figure 5–35 of the 1995 Protocol,[37] the highest leak percentage is identified during the first monitoring event. The leak percentage then declines over time and reaches a point of steady state where the leak percentage is lower than that identified in the first monitoring event. We therefore evaluated a stepped approach, using 2 years as the initial period (as suggested by the petitioner) before reaching the steady state. Additional information regarding the cost of control and emission reductions is available in section 2.5 of the TSD located at Docket ID No. EPA–HQ–OAR–2017–0483.

These costs of control for both the semiannual and annual monitoring frequencies may appear to be reasonable for non-low production well sites. However, as explained above regarding the three areas of concern, we acknowledge that our updated analysis may overestimate the emission reductions achieved under semiannual monitoring and the number of fugitive emissions components identified during semiannual monitoring. Therefore, we are unable to conclude that semiannual monitoring is cost effective. While we have also overestimated the cost effectiveness of the stepped approach and annual monitoring for the same reasons discussed above, the overestimate would be less compared to that for semiannual monitoring. As mentioned earlier, petitioners have requested that we consider annual monitoring, which suggests that they are able to bear such costs. In light of all these considerations, we are therefore proposing to revise the monitoring frequency for the collection of fugitive emissions components located at non-low production well sites from

[30] Alaska, Arkansas, Colorado, Louisiana, Montana, New Mexico, North Dakota, Ohio, Oklahoma, Pennsylvania, Texas, Utah, West Virginia, and Wyoming.

[31] See memorandum *EPA Analysis of Well Site Fugitive Emissions Monitoring Data Provided by API* located at Docket ID No. EPA–HQ–OAR–2017–0483. April 17, 2018.

[32] See 81 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 equally controlled, therefore half of the cost is apportioned to the methane emission reductions and half of the cost is apportioned to the VOC emission reductions. In this evaluation, we examined both approaches across the range of identified monitoring frequencies: Semiannual, annual, and semiannual for 2 years followed by annual.

[33] The TSD also include an analysis of the cost of control for the stepped monitoring frequency; however, we are not considering this for proposal in this action because we do not currently have information to understand how fugitive emission percentage change over time or how long it takes to achieve the steady state percentage at non-low production well sites.

[34] While the petitioner used the term leaking, EPA is clarifying they were referring to fugitive emissions, and not equipment leaks such as those subject to a leak detection and repair (LDAR) program at onshore natural gas processing plants.

[35] See Docket ID No. EPA–HQ–OAR–2010–0505–7682.

[36] See *Final Impacts Analysis for Regulatory Options for Equipment Leaks of VOC in the SOCMI,* located at Docket ID. EPA–HQ–OAR–2006–0699–0090 at p. 8.

[37] U.S. Environmental Protection Agency, Protocol for Equipment Leak Emission Estimates. Section 5.3 and Figure 5–35. November 1995 (EPA–453/R–95–017).

semiannual monitoring to annual monitoring.

We are soliciting comment on the proposed annual monitoring for non-low production well sites and additional information to address the uncertainties described previously. There are several well sites that have incorporated fugitive monitoring programs prior to the 2016 NSPS OOOOa for various purposes, including compliance with state or local requirements. Data from these programs could provide the information necessary to refine our model plant analysis. We are soliciting data regarding the percentage of fugitive emissions components identified with fugitive emissions at these well sites for each survey performed to understand how this percentage may change over time or based on monitoring frequency; the data should include information on when the well site began producing, the start date of the fugitive program at the well site, the frequency of monitoring, an indication of the location of the well site *(e.g.,* basin name or state), and how the surveys are performed, including the monitoring instrument used and the regulatory program followed. We are also soliciting comment and supporting data on the stepped monitoring frequency for non-low production well sites, including information to determine the appropriate period for more frequent monitoring prior to stepping down to less frequent monitoring. We further solicit comment whether, should we still lack information of the type solicited in this paragraph, the existing uncertainties and absences of information described in this notice support the monitoring frequencies proposed in this notice, the monitoring frequencies in the 2016 NSPS OOOOa, or some other result.

The EPA is soliciting information that can be used to evaluate if additional changes are necessary to the model plants. Specifically, the EPA requests information that has been collected from implementing fugitive monitoring programs, including information on leak concentrations where Method 21 has been used for monitoring. This information could also demonstrate the actual equipment counts or fugitive emissions component counts at the well site, in relation to the number of fugitive emissions identified during each monitoring survey.

Further, we are proposing that fugitive monitoring may stop when an owner or operator removes all major production and processing equipment from the well site, such that it contains only one or more wellheads. The 2016 NSPS OOOOa excludes well sites that contain only one or more wellheads from the fugitive emissions requirements because fugitive emissions at such well sites are extremely low. 80 FR 56611. In the preamble to the 2015 NSPS OOOOa proposal, we noted that wellhead only well sites do not have ancillary equipment (such as storage vessels, closed vent systems, control devices, compressors, separators, and pneumatic controllers), thus resulting in low emissions. For the same reason, we anticipate that, when a well site becomes a wellhead only well site due to the removal of all ancillary equipment, its fugitive emissions would also be extremely low because the number of fugitive emissions components is low. This proposal uses the term ''major production and processing equipment'' to refer to ancillary equipment without which the fugitive emissions would be extremely low. We are, therefore, proposing to define ''major production and processing equipment'' as including separators, heater treaters, storage vessels, glycol dehydrators, pneumatic pumps, or pneumatic controllers. We have also evaluated the cost-effectiveness of monitoring a wellhead only well site and find it not to be cost-effective. For that analysis, we developed a model plant that contains only 2 wellheads and no major production and processing equipment. For the annual monitoring frequency, we found the cost for control was greater than $5,000 per ton of methane reduced and greater than $20,000 per ton of VOC reduced.[38] Additional discussion about this model plant and the cost of control is included in the TSD. In light of the above, because fugitive emissions are anticipated to be extremely low and control costs are estimated to be elevated, we are proposing that monitoring may discontinue when all major production and processing equipment at a well site has been removed, resulting in a wellhead only well site. We are soliciting comment on the proposed exemption and definition of major production and processing equipment for purposes of this specific proposal, including whether additional equipment should be included in this list, such as compressors and engines.

As explained above, we are proposing that monitoring is no longer required when all major production and processing equipment at a well site has been removed, resulting in a wellhead only well site. We note that if the production from this well site (with all major production and processing equipment removed), is sent to a separate tank battery for processing, that separate tank battery (which itself is a well site as defined in 40 CFR 60.5430a) is considered modified and subject to the fugitive emissions requirements. Additional discussion on this topic is included in section VI.B.2 of this preamble. We further note that the proposed monitoring exemption would not change the affected facility status of the collection of fugitive emissions components located at a well site that removes equipment to become a wellhead only well site; it would remain an affected facility. We are proposing to require that owners or operators report the following information in the next annual report following the change to a wellhead only well site: (1) A statement that the well site has removed all major production and processing equipment, (2) the final date that equipment was removed, (*i.e.,* the date that the well site began meeting the definition of a wellhead only well site), and (3) the location receiving the production from the well site. Provided the well site remains a wellhead only well site, no additional reporting related to fugitive emissions would be required. If in the future production equipment is reintroduced to the well site, the fugitive emissions requirements would restart with initial monitoring followed by the subsequent monitoring, the frequency of which would be based on the subcategory (non-low production or low production) that the well site was classified as when it first became an affected facility for fugitive emissions requirements (*e.g.* not the subcategory that the well site is classified when production equipment is reintroduced). We are soliciting comment on this proposed exemption from monitoring for well sites that become wellhead only sites, including the proposed reporting requirements and subsequent monitoring requirements should the wellhead only status of the well site later change.

Low Production Well Sites. The 2016 NSPS OOOOa requires semiannual monitoring for all well sites, regardless of the production levels for the well site. In 2015, the EPA proposed to exclude low production well sites (*i.e.,* well sites where the average combined oil and natural gas production is less than 15 boe per day averaged over the first 30 days of production) from fugitive emissions requirements. 80 FR 56639. It

[38] We did not perform an analysis for the cost of control at a semiannual monitoring frequency for these wellhead only well sites because we determined that annual monitoring was not cost-effective. Therefore, at more frequent monitoring would also not be cost-effective because there are higher costs compared to annual monitoring.

was our understanding in 2015 that fugitive emissions were low at low production well sites and that these well sites were mostly owned and operated by small businesses. We were concerned about the burden on small businesses, especially with relatively low emission reduction potential. *Id.* However, in the preamble to the final 2016 NSPS OOOOa, the EPA stated that we ''believe that low production well sites have the same type of equipment (*e.g.,* separators, storage vessels) and components (*e.g.,* valves, flanges) as well sites with production greater than 15 boe per day. Because we did not receive additional data on equipment or component counts for low production wells, we believe that a low production well model plant would have the same equipment and component counts as a non-low production well site.'' 81 FR 35856. We based this conclusion on the fact that we had no data to indicate that the number and types of equipment were different at low production well sites than at non-low production well sites. Additionally, comments received on the 2015 proposal indicated that small businesses would not benefit from the proposed exemption because these types of wells would not be economical to operate and few operators, if any, would operate new low production well sites. *Id.*

In a letter dated April 18, 2017, the Administrator granted reconsideration of several aspects of the 2016 NSPS OOOOa, including applying the fugitive emissions requirements at 40 CFR 60.5397a to low production well sites.[39] The petitioner who raised this issue for reconsideration identified in its petition what they classified as an inconsistency between the EPA's justification for not exempting low production well sites from the fugitive emissions requirements and the EPA's rationale for the definition of modification for purposes of those same requirements.[40] This petitioner observed that it appeared the EPA relied on data indicating the same equipment counts were present at all well sites regardless of production levels to justify regulating fugitive emissions at low production well sites, while defining modification by events that increase production (*i.e.,* drilling a new well, hydraulic fracturing a well, or hydraulic refracturing a well), which the EPA concludes will increase emissions whether or not there is change in component counts. The petitioner then stated that:

> EPA's rationale, that fugitive emissions are a function of the number and types of equipment, and not operating parameters such as pressure and volume, is inconsistent with EPA's justification for what constitutes a 'modification' for an existing well site. EPA assumes that fracturing or refracturing an existing well will increase emissions because of the additional production, *i.e.,* the additional pressure and volume. EPA cannot ignore the laws of physics to the detriment of low production wells in one instance and then 'honor' them in another context to eliminate an 'emissions increase' requirement in the traditional definition of 'modification.'[41]

As we explain in detail in section VI.B.2 related to modifications, operating pressures and volumes are one set of factors that can cause changes in the fugitive emissions at a well site. However, as described below, there is support for the petitioners' assertion that equipment counts can vary based on the amount of production at a well site.[42]

The petitioners noted that as production increases it is possible that additional major production and processing equipment is added to the well site to handle this increase. The inverse impact was also presented by petitioners, in that as production declines, major production and processing equipment is either disconnected or removed from the well site so it can be used somewhere else.[43] Additionally, the petitioners noted that operating pressures for the well site are generally affected by production, and depleted wells may not be able to provide enough pressure to meet the pressure requirements of the gas gathering system.[44] In comments submitted on the November 2017 Notice of Data Availability (''2017 NODA''), one commenter noted that the information used as the basis for the EPA's decision to treat low production well sites the same as non-low production well sites was based on a flawed analysis of the data.[45] This commenter noted that emissions were presented in such a way as to compare the total well site emissions as a percentage of production. As noted by the commenter, this type of analysis unfairly makes it appear that low production well sites are ''super-emitters'' because when emissions are compared based on a percentage of production, even small emissions can appear to be upwards of 50 percent or more of the total production for the well site. Further, one petitioner reiterated concerns about the impacts of fugitive emissions requirements on small businesses, including stating that the ''marginal profitability will mean that many wells will be shut in instead of making the investment to conduct LDAR surveys.''[46] We solicit information confirming or refuting this concern including analyses of the number of wells that may be shut in as a result of requiring fugitive emissions monitoring and how these concerns may vary based on production level (presumably wells with higher production would be better able to adsorb more frequent monitoring). At a minimum, any information provided should include the costs of implementing the fugitive emissions requirements compared to the profitability of the well site over the life of the well site from first production through shut in. Further, any information provided should include information as to the length of the life of the well site, beginning at first production, and by how much that total duration would be shortened by the shut in, as well as information as to total production over the life of the well site, beginning at first production, and the amount of production that would be reduced by the shut in. If information received supports the allegation that fugitive emissions monitoring would lead to a significant number of shut-ins at a significantly earlier point in the life of the well site and with a significant loss of overall production volume, that would further support our proposals regarding monitoring frequency. However, assertions presented without supporting information will be of limited or no utility in this analysis.

In light of the comments, the petitions, and data made available after promulgation of the 2016 NSPS OOOOa, the EPA has re-examined whether fugitive emissions are different for low production well sites. Following promulgation of the 2016 NSPS OOOOa, the EPA received information from one stakeholder which contained component level emissions information for well sites in the Dallas/Fort Worth area (herein referred to as the ''Fort Worth Study'').[47] The EPA evaluated

[39] See Docket ID No. EPA–HQ–OAR–2010–0505–7730.

[40] See Docket ID No. EPA–HQ–OAR–2010–0505–7685.

[41] See Docket ID No. EPA–HQ–OAR–2010–0505–7685, p. 5.

[42] See Docket ID No. EPA–HQ–OAR–2010–0505–7682.

[43] See Docket ID No. EPA–HQ–OAR–2010–0505–7682, p. 12.

[44] *Id.*

[45] See Docket ID No. EPA–HQ–OAR–2010–0505–12454.

[46] See Docket ID No. EPA–HQ–OAR–2010–0505–7685.

[47] ''The Natural Gas Air Quality Study (Final Report),'' prepared by Eastern Research Group, Inc.

Continued

the emissions calculation workbook included in Appendix 3–B of the Fort Worth Study and was able to identify 27 well sites with throughput less than 90 thousand cubic feet per day (Mcfd), or 15 boe per day. While this throughput was the throughput reported for the prior day and not the average over the first 30 days as we are defining low production well sites in this proposed reconsideration, this information was relevant to understanding both component counts and emissions for the well sites in the study as compared to production values. As explained in the memorandum *Analysis of Low Production Well Site Fugitive Emissions from the Fort Worth Air Quality Study* (''Fort Worth Study Memo''), located at Docket ID No. EPA–HQ–OAR–2017–0483, the EPA was able to directly compare fugitive component emissions from these 27 low production well sites to the fugitive component emissions from the other approximately 300 well sites in the study. This evaluation demonstrated that average emissions across the low production well sites were lower than those at the non-low production well sites in the study. Additionally, the average equipment counts were also lower for the low production well sites than those at non-low production well sites in the study. When fugitive emissions were considered from non-tank and non-controller fugitive sources, the average methane emissions were approximately 2.5 tpy for low production well sites, and 24 tpy for non-low production well sites. When storage vessel fugitives (*e.g.,* thief hatches) were considered, average methane emissions were 13 tpy for low production well sites and 33 tpy for non-low production well sites.[48]

Given this information, the EPA for this proposal has evaluated fugitive emissions from well sites by subcategorizing well sites based on production: (1) Non-low production and (2) low production. Within each of these subcategories, the EPA has modified the three model plants used in the 2016 NSPS OOOOa: Gas well site, oil well site (defined as GOR <300), and oil with associated gas well site (defined as GOR ≥300). A discussion of the non-low production well site model plants is included in the discussion above on the pathway to less frequent monitoring.

The EPA created new model plants using the component count information obtained for the low production well sites in the Fort Worth Study in order to compare the emissions using the emissions factors used by the EPA for model plant calculations to the measured emissions from the study. For the low production gas well site model plant, we used the average equipment counts for the low production well sites in the Fort Worth Study. We then compared the corresponding average component counts (*e.g.,* valves, connectors) for this equipment in the low production gas well site to the non-low production gas well site to determine a scaling factor. This scaling factor was applied to the non-low production component counts for the oil well site and oil with associated gas well site model plants in order to evaluate these types of well sites for the low production subcategory. Additional information about the low production well site model plants and analysis is included in the TSD.

As mentioned previously, in the 2016 NSPS OOOOa the EPA did not expect production levels to affect the amount of major production and processing equipment at well sites. However, as discussed above, we have since evaluated data showing that low production wells have fewer equipment components, and therefore fewer fugitive emissions. Therefore, in this proposal, we have incorporated the new data and developed model plants for low production well sites. The estimated emissions and cost-effectiveness are different between the low production and non-low production well site model plants. For example, the estimated baseline methane emissions are 5.91 and 4.80 tpy for non-low production and low production gas well site model plants, respectively. We performed additional analysis on the emissions data presented in the Fort Worth Study to determine if there was a statistical difference between the low production and non-low production methane emissions. This analysis determined the mean methane emissions were 157 and 116 tpy for non-low production and low production well sites, respectively. Additional information on this analysis is included in the Fort Worth Study Memo located at Docket ID No. EPA–HQ–OAR–2017–0483.

In addition to the Fort Worth Study, the EPA evaluated other available information for comparing low and non-low production well sites. While we did not find the same level of detail regarding component counts to allow us to further refine the low production well site model plants, several of the studies indicated that there is a general correlation between production and fugitive emissions, where fugitive emissions increase as production increases at the well site. Further, some studies indicated that while the number of fugitive emissions components was lower for low production well sites (contrary to our assumption in the 2016 NSPS OOOOa), a few outliers were identified suggesting that low production well sites may have the potential for fugitive emissions greater than the estimates in the model plants. Finally, the studies also indicated that storage vessel thief hatches were a large source of fugitive emissions when compared to other fugitive emissions components, such as valves and connectors. Additional information about these studies is presented in the memorandum *Low Production Well Site Fugitive Emissions* (''Low Production Memo''), located at Docket ID No. EPA–HQ–OAR–2017–0483.

In addition to the potential overestimates of emissions discussed related to non-low production well sites, our re-assessment of our 2016 analysis indicates that we may have overestimated emissions and the potential for emission reductions from low production well sites. As we have described previously, the number of each type of major production and processing equipment located at low production well sites may differ from that at non-low production well sites, and we are not certain this has been adequately taken into account with the limited data available[49] from the Fort Worth Study. The equipment that is present at a low production well site is typically designed for lower operating conditions, such as volume and pressure, therefore, the equipment may be smaller and composed of fewer fugitive emission components than those estimated in the model plants. As discussed in further detail in the TSD, we used the average major production and processing equipment counts from the Fort Worth Study as the basis for the low production model plants; however, because the Fort Worth Study does not provide component count data by equipment, we assigned the same average component counts per major equipment (*i.e.,* the same number of valves per separator as the number of valves per separator at non-low

July 13, 2011, *available at http://fortworthtexas.gov/gaswells/air-quality-study/final/.*

[48] See the memorandum *Analysis of Low Production Well Site Fugitive Emissions from the Fort Worth Air Quality Study,* located at Docket ID No. EPA–HQ–OAR–2017–0483.

[49] The site-specific data available in the Fort Worth Study is limited to approximately 300 natural gas well sites located near the City of Fort Worth, Texas. Most of the well sites consisted of dry gas, with no information available on oil well sites. We are uncertain the major production and processing equipment counts presented in this study are representative of well sites located in other areas of the country, and solicit information regarding operations in other areas.

production well sites). Therefore, there is evidence to suggest that we may have overestimated the fugitive emissions component counts for low production well sites. Additionally, the petitioners assert that the operating pressures are much lower for low production well sites than for non-low production well sites, and we do not have a mechanism to account for operating pressure changes in our model plants.[50] However, in section VI.B.2 of this preamble, we discuss comments from petitioners stating that operating pressures may be driven, in part, by sales line pressures such that decreased production levels may not allow for operations below the gas sales line pressures. In such circumstances, the low production well site would need to produce at or above the relevant gas sales line pressure. This may result in decreased dump frequency or duration, and therefore, reduced periods of fugitive emissions during operation. While lower operating pressure and decreased dump frequency or duration would result in lower fugitive emissions, we do not have enough information to determine the likelihood of decreased operating pressure or decreased dump frequency or duration in order to account for them in our model plant analysis.

Despite the potential overestimation of emissions and emission reductions for low production well sites, we examined the costs and emission reductions for several monitoring frequencies to determine the cost of control for the newly created low production well site model plant. As a result of this review, there is evidence to support the petitioners' assertion that low production well sites are different than non-low production well sites. The TSD presents the cost of control for semiannual, stepped, annual and biennial monitoring frequencies.[51]

After considering the differences in emissions between non-low production and low production well sites, and the reasons to believe that we have overestimated emission reductions and percentage of fugitive emissions, we are proposing to change the current monitoring frequency for low production well sites from semiannual monitoring to biennial monitoring, or monitoring every other year. We are soliciting comment on the biennial monitoring requirement for low production well sites. Additionally, we are soliciting data on the number of major production and processing equipment (*e.g.,* separators, heater treaters, glycol dehydrators, and storage vessels) and the number of fugitive emissions components (*e.g.,* valves, open-ended lines, and connectors) located at these well sites, as well as the operating pressures of these well sites considering gas sales line pressures and the number of major production and processing equipment located at the well site (*e.g.,* separators and heater treaters). Further, the EPA is proposing that low production well sites are defined as those well sites where the average combined oil and natural gas production is less than 15 boe per day averaged over the first 30 days of production. We are soliciting comment on the definition of a low production well site, including those where all the wells located on the well site have production below 15 boe per day. We are proposing specific recordkeeping and reporting requirements in 40 CFR 60.5420a, including a requirement to describe how the well site determined it is a low production well site. We are soliciting comment on the recordkeeping and reporting requirements, including alternative information that would provide the combined production of oil and natural gas for the well site. In addition to soliciting comment on the biennial monitoring frequency, we are also soliciting comment and supporting data on an exemption from fugitive emissions requirements at low production well sites, for well sites both with and without controlled storage vessels.

Monitoring Frequency for Compressor Stations. The 2016 NSPS OOOOa requires initial and quarterly monitoring of the collection of fugitive emissions components located at compressor stations. As noted in section VI.B.1 of this preamble, we received petitions requesting less frequent monitoring, specifically semiannual monitoring for compressor stations.[52] In this action, we are co-proposing semiannual and annual monitoring of the collection of fugitive emissions components located at compressor stations not located on the Alaskan North Slope. (See ''Well Sites and Compressor Stations Located on the Alaskan North Slope'' for the proposed actions related to those sites.)

Similar to the information received about fugitive monitoring at well sites, the EPA received information from two stakeholders regarding fugitive emissions monitoring at compressor stations.[53] [54] Some of the information provided the number of fugitive emission components monitored and the number and percentages of fugitive emissions components identified with fugitive emissions for 110 gathering and boosting compressor stations.[55] One of these stakeholders asserted the data provided regarding gathering and boosting stations would support changing the monitoring frequency for compressor stations to annual monitoring. Some of this data was specific to the required monitoring of the 2016 NSPS OOOOa, while other information was specific to monitoring requirements for various state programs or consent decrees. One company provided the number of fugitive emissions identified during initial monitoring at 17 stations, and subsequent fugitive emissions counts for up to 6 total surveys, however, not all stations are represented in subsequent surveys. While fugitive emissions counts were included in this submission, no other information was provided about the number of components monitored. It was difficult for us to make any conclusions from the information, but we were able to recognize that for at least one company, the average reported initial percentage of identified fugitive emissions is almost 1.5 percent, which is higher than the 1.18 percent used for our model plant calculations. However, no conclusions can be drawn from this single data point and we did not make updates to the model plants as a result of this information. The EPA performed a sensitivity analysis using this data to understand how the cost of control would change if we applied the data provided to compressor stations and included this analysis in the TSD. This analysis did not alter the conclusions that we had reached using the 1.18 percent value.

We are soliciting comment on our analysis of the information provided by this stakeholder,[56] including additional data that will allow for further analysis of fugitive emissions monitoring at

[50] See Docket ID Nos. EPA–HQ–OAR–2010–0505–7682 and EPA–HQ–OAR–2010–0505–7685.

[51] See the TSD for full comparison of cost.

[52] See Docket ID Nos. EPA–HQ–OAR–2010–0505–7682, EPA–HQ–OAR–2010–0505–7685 and EPA–HQ–OAR–2010–0505–7686.

[53] See letter from GPA Midstream Association Re: GPA Midstream OOOOa White Paper Supplemental Information, March 5, 2018, located at Docket ID No. EPA–HQ–OAR–2017–0483.

[54] See memorandum *NSPS OOOOa Monitoring Case Study Presentation by Terence Trefiak with Target Emission Services* located at Docket ID No. EPA–HQ–OAR–2017–0483. March 13, 2018.

[55] See memorandum *EPA Analysis of Compressor Station Fugitive Emissions Monitoring Data Provided by GPA Midstream* located at Docket ID No. EPA–HQ–OAR–2017–0483. April 17, 2018.

[56] See memorandum *EPA Analysis of Compressor Station Fugitive Emissions Monitoring Data Provided by GPA Midstream* located at Docket ID No. EPA–HQ–OAR–2017–0483. April 17, 2018.

compressor stations. The EPA is also soliciting information that can be used to evaluate if changes are necessary to the model plants. Specifically, the EPA requests information that has been collected from implementing fugitive monitoring programs. This information could demonstrate the actual equipment counts or fugitive emissions component counts at the compressor station, in relation to the number of fugitive emissions identified during each monitoring survey. Finally, the EPA solicits comment and information on costs associated with implementing a fugitive emissions monitoring program.

The unique operating characteristics of compressor stations may support more frequent monitoring of compressor stations as compared to well sites. The collection of fugitive emissions components located at compressor stations are subject to vibration and temperature cycling. Some studies indicate that components subject to vibration, high use, or temperature cycling are the most leak-prone.[57] The EPA best practices guide for LDAR states that more frequent monitoring should be implemented for components that contribute most to emissions.[58] Similarly, the Canadian Association of Petroleum Producers issued a best management practice for the management of fugitive emissions at upstream oil and gas facilities in 2007. That document states, ''the equipment components most likely to leak should be screened most frequently.'' [59]

Additionally, information was also provided by one stakeholder that indicates the operating mode of the compressor(s) located at the station was a key piece of information when detecting fugitive emissions.[60] For instance, the stakeholder stated that when compressors were in standby mode, the detected fugitive emissions were lower. We had not previously considered that compressors may not be operating during the fugitive emissions survey, therefore, we are proposing that owners or operators keep a record of the operating mode of each compressor at the time of the monitoring survey, and a requirement that each compressor must be monitored at least once per calendar year when it is operating. If the operating mode of individual compressors has an impact on the occurrence of fugitive emissions, it may provide support for more frequent monitoring, or, alternatively, a requirement to monitor when compressors are operating reflective of normal operating conditions. For example, if the EPA were to move to an annual monitoring frequency, owners and operators might conduct fugitive emissions monitoring during scheduled maintenance periods such as times when there is less demand on the station. This might present the appearance of lower fugitive emissions than if the monitoring occurred during peak seasons, thus decreasing the effectiveness of the program for controlling fugitive emissions, unless the monitoring procedure can assure that does not occur. The EPA is soliciting comment related to the effect the compressor operating mode has on fugitive emissions and comment on a requirement to conduct monitoring only during times that are representative of operating conditions for the compressor station.

There are a number of important factors to consider when selecting the appropriate monitoring frequency for fugitive emissions components located at compressor stations such as the operating modes that likely affect the number and magnitude of fugitive emissions and costs. In light of the concerns from the petitioners that less frequent monitoring than the current requirement of quarterly monitoring would be appropriate, the EPA performed a sensitivity analysis to understand how the monitoring frequencies would affect emission reductions and costs. We examined the costs and emission reductions for the compressor station model plant at quarterly, semiannual, and annual monitoring frequencies. We applied the two approaches used in the 2016 NSPS OOOOa (single and multipollutant approaches) [61] for evaluating cost-effectiveness of these three monitoring frequencies for the fugitive emissions program for reducing both methane and VOC emissions from non-low production well sites. In addition to evaluating the total cost-effectiveness of the different monitoring frequencies, the EPA also estimated the incremental costs of going from the baseline of no monitoring to annual, from annual to semiannual, and from semiannual to quarterly. The incremental cost of control provides insight into how much it costs to achieve the next increment of emission reductions going from one stringency level to the next, more stringent level, and thus is an appropriate tool for distinguishing among the effects of different stringency levels. Table 3 summarizes the total and incremental costs of control for each of the monitoring frequencies evaluated at compressor stations. Additional information regarding the cost of control and emission reductions is available in section 2.5 of the TSD located at Docket ID No. EPA–HQ–OAR–2017–0483.

TABLE 3—NATIONWIDE EMISSIONS REDUCTION AND COST IMPACTS OF CONTROL FOR FUGITIVE EMISSIONS COMPONENTS LOCATED AT COMPRESSOR STATIONS

[Year 2015]

Frequency	Capital cost (million $)	Annualized costs without recovery credits (million $/yr)	Emissions reduction, methane (tpy)	Emissions reduction, VOC (tpy)	Total cost-effectiveness without recovery credit ($/ton methane)	Total cost-effectiveness without recovery credit ($/ton VOC)	Incremental cost-effectiveness without recovery credit ($/ton methane)	Incremental cost-effective-ness without recovery credit ($/ton VOC)
Annual	0.42	2.05	3,680	850	550	2,410		
Semiannual	0.42	3.6	5,510	1,270	650	2,830	840	3,650
Quarterly	0.42	6.7	7,350	1,700	910	3,950	1,690	7,300

[57] Canadian Association of Petroleum Producers, ''Best Management Practice. Management of Fugitive Emissions at Upstream Oil and Gas Facilities,'' January 2007.

[58] U.S. Environmental Protection Agency, ''Leak Detection and Repair: A Best Practices Guide,'' EPA–305–D–07–001, October 2007.

[59] Canadian Association of Petroleum Producers, ''Best Management Practice. Management of Fugitive Emissions at Upstream Oil and Gas Facilities,'' January 2007.

[60] See memorandum *NSPS OOOOa Monitoring Case Study Presentation by Terence Trefiak with Target Emission Services* located at Docket ID No. EPA–HQ–OAR–2017–0483. March 13, 2018.

[61] See 81 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 equally controlled, therefore half of the cost is apportioned to the methane emission reductions and half of the cost if apportioned to the VOC emission reductions. In this evaluation, we examined both approaches across the range of identified monitoring frequencies: Semiannual, annual, and stepped (semiannual for 2 years followed by annual).

We continue to recognize the limitations in our emissions estimation method, as described for non-low production well sites. As mentioned above, we recognize the distinct operational characteristics of compressor stations that may cause increased fugitive emissions may support more frequent monitoring than proposed for well sites. At this time, we recognize that our analysis likely overestimates the emission reduction and therefore, the cost-effectiveness of each of the three monitoring frequencies for compressor stations due to the same uncertainties described previously for non-low production well sites (*e.g.,* assumed constant percentage of fugitive emissions, uncertainties regarding emission reductions achieved, etc.). Due to these uncertainties, we are unable to conclude that quarterly monitoring is cost-effective for compressor stations, thus we are co-proposing semiannual monitoring for compressor stations. The EPA is soliciting comment and information that will allow us to further refine our model plant analysis, including information regarding emission reductions and the relationship to monitoring frequencies. We are soliciting comment on quarterly monitoring, and our analysis of the factors that may contribute to increased fugitive emissions at compressor stations. Additionally, we are soliciting data in order to understand how the percentage of identified fugitive emissions may change over time; the data should include the date of construction of the compressor station, information on when the compressor station began its fugitive program, the frequency of monitoring, an indication of the location of the compressor station, and how the surveys are performed, including the monitoring instrument used and the regulatory program followed.

Finally, the EPA is also noting that another stakeholder presented an analysis of third party studies and reports as justification for annual monitoring at compressor stations.[62] In their analysis, the stakeholder states that the EPA has underestimated the control effectiveness of annual OGI monitoring and overestimated emissions from fugitive emissions components at compressor stations. For example, the stakeholder states that annual OGI monitoring at compressor stations can achieve 80 percent emissions reductions, compared to the EPA's estimate of 40 percent emissions reductions. Additionally, the stakeholder compares the EPA model plant emission estimates to measurement data reported under the requirements of 40 CFR part 98, subpart W—Petroleum and Natural Gas Systems (''Subpart W'') as compiled and described in the Pipeline Research Council International, Inc. (PRCI) study report.[63] The EPA has reviewed the information and analyzed the referenced third-party reports to determine if the information would support annual monitoring. The EPA has several concerns with the analysis and conclusions presented by the stakeholder, as discussed in the memorandum describing our analysis,[64] therefore, the EPA is unable at this point to conclude that this information supports annual monitoring for compressor stations. We are co-proposing semiannual and annual monitoring for compressor stations, and soliciting comment and supporting information related to our analysis of the information, including data that sheds further light on which monitoring frequency (annual, semiannual, or quarterly) is most appropriate.

Well Sites and Compressor Stations Located on the Alaskan North Slope. On March 12, 2018, the EPA amended the 2016 NSPS OOOOa to include separate monitoring requirements for the collection of fugitive emissions components located at well sites located on the Alaskan North Slope.[65] As explained in that action, such separate requirements were warranted due to the area's extreme cold temperature, which is below the temperatures at which the monitoring instruments are designed to operate for approximately half of a year. The amended requirements for the collection of fugitive emissions components located at well sites located on the Alaskan North Slope specify that new well sites that startup production between September and March must conduct initial monitoring within 6 months of the startup of production[66] or by June 30, whichever is later, while well sites that startup production between April and August must comply with the 60-day initial monitoring requirement in the 2016 NSPS OOOOa. Similarly, well sites that are modified between September and March must conduct initial monitoring within 6 months of the first day of production for each collection of fugitive emissions components or by June 30, whichever is later. Further, all well sites located on the Alaskan North Slope that are subject to the fugitive emissions requirements must conduct annual monitoring, instead of the semiannual monitoring required for other well sites. Subsequent annual monitoring must be conducted at least 9 months apart.

Compressor stations located on the Alaskan North Slope experience the same extreme cold temperatures as the well sites located on the Alaskan North Slope. One petitioner[67] cautioned that the monitoring technology specified in the 2016 NSPS OOOOa (*i.e.,* optical gas imaging (OGI) and the instruments for Method 21) cannot reliably operate at well sites on the Alaskan North Slope for a significant portion of the year due to the lengthy period of extreme cold temperatures.[68] According to manufacturer specifications, OGI cameras, which the EPA identified in the 2016 NSPS OOOOa as the BSER for monitoring fugitive emissions at well sites, are not designed to operate at temperatures below −4 °F,[69] and the monitoring instruments for Method 21, which the 2016 NSPS OOOOa provides as an alternative to OGI, are not designed to operate below +14 °F.[70] One commenter provided data, and the EPA confirmed with its own analysis, that temperatures below 0°F are a common occurrence on the Alaskan North Slope between November and April.[71] In light of the above, there is no assurance that the initial and quarterly monitoring that must occur during that period of time are technically feasible for compressor stations located on the Alaskan North

[62] See ''Methane Emissions from Natural Gas Transmission and Storage Facilities: Review of Available Data on Leak Emission Estimates and Mitigation Using Leak Detection and Repair'', prepared for INGAA by Innovative Environmental Solutions, Inc., June 8, 2018 and ''Supplement to INGAA White Paper on Subpart OOOOa TSD Estimates of Leak Emissions and LDAR Performance'', from Jim McCarthy and Tom McGrath, Innovative Environmental Solutions, Inc., June 20, 2018 located at Docket ID No. EPA–HQ–OAR–2017–0473.

[63] GHG Emission Factor Development for Natural Gas Compressors, PRCI Catalog No. PR–312–1602–R02, April 18, 2018.

[64] See memorandum *EPA Analysis of Fugitive Emissions Data Provided by INGAA* located at Docket ID No. EPA–HQ–OAR–2017–0483. August 21, 2018.

[65] 83 FR 10628.

[66] Startup of production is defined in 40 CFR 60.5430a.

[67] See Docket ID No. EPA–HQ–OAR–2010–0505–7682.

[68] See Docket ID No. EPA–HQ–OAR–2010–0505–12434.

[69] See FLIR Systems, Inc. product specifications for GF300/320 model OGI cameras at *http://www.flir.com/ogi/display/?id=55671.*

[70] See Thermo Fisher Scientific product specification for TVA–2020 at *https://assets.thermofisher.com/TFS-Assets/LSG/Specification-Sheets/EPM-TVA2020.pdf.*

[71] See information on average hourly temperatures from January 2010 to January 2018 at the weather station located at Deadhorse Alpine Airstrip, Alaska. Obtained from the National Oceanic and Atmospheric Administration (NOAA)'s National Centers for Environmental Information and summarized in Docket ID No. EPA–HQ–OAR–2010–0505–12505.

Slope. Additionally, while the 2016 NSPS OOOOa provides a waiver from one quarterly monitoring event when the average temperature is below 0F for two consecutive months, this waiver would not fully address the issues for compressor stations located on the Alaskan North Slope. As discussed above, temperatures are below 0 °F between November and April, which spans across two quarters. The low temperature wavier, only allows missing one quarterly monitoring event. Based on available information, we have concluded that semiannual monitoring is not feasible for well sites located on the Alaskan North Slope, therefore, conducting three quarterly monitoring events is likewise not feasible for compressor stations. Therefore, we are proposing amendments to the fugitive emissions requirements in the 2016 NSPS OOOOa as they apply to compressor stations located on the Alaskan North Slope.

We are proposing to establish separate fugitive monitoring requirements for compressor stations located on the Alaskan North Slope because of the technical infeasibility issues with the operations of the monitoring instruments discussed above. Similar to well sites located on the Alaskan North Slope, we are proposing that new compressor stations that startup between September and March must conduct initial monitoring within 6 months of startup, or by June 30, whichever is later. Similarly, we are proposing that modified compressor stations located on the Alaskan North Slope that become modified between September and March must conduct initial monitoring within 6 months of the modification, or by June 30, whichever is later. Compressor stations that startup or are modified between April and August would meet the 60-day initial monitoring requirement in the 2016 NSPS OOOOa. However, as discussed in section VI.B.3, we are soliciting comment on extending the time frame for conducting the initial monitoring for all well site and compressor station fugitive emissions components subject to the 2016 NSPS OOOOa, including those located on the Alaskan North Slope. Further, we are proposing that all compressor stations located on the Alaskan North Slope that are subject to the fugitive emissions requirements must conduct annual monitoring. Subsequent annual monitoring must be conducted at least 9 months apart, but no more than 13 months apart.

As discussed in section VI.B.3 of this preamble (Initial Monitoring for Well Sites and Compressor Stations), the EPA is soliciting comment on whether to extend the period for conducting initial monitoring for well sites and compressor stations because additional time is needed to complete installation of equipment. For the same reason, the EPA is soliciting comment on whether to extend the time frame for initial monitoring for well sites that start up production and compressor stations that start up between April and August, and for those that are modified during this period. Further discussion on this topic is included in section VI.B.3 of this preamble, which describes the concerns raised and the timeframes suggested by petitioners (180 days) and the EPA (90 days) to address such concerns. In addition to the information specified in that subsection, we are soliciting comments and information specific to the well sites and compressor stations located on the Alaskan North Slope regarding allowing additional time for the initial monitoring. Upon receiving and reviewing the relevant information, the EPA may conclude that amendment to extend the timeframe for conducting the initial monitoring is necessary for all or some well site and compressor station fugitive emissions components subject to the 2016 NSPS OOOOa, including those located on the Alaskan North Slope.

One petitioner [72] requested that the EPA exempt well sites and compressor stations located on the Alaskan North Slope from fugitive emissions monitoring, similar to the exemptions from LDAR at natural gas processing plants provided in the 2012 NSPS OOOO and the 2016 NSPS OOOOa. The petitioner stated the reasons for applying an exemption to natural gas processing plants are also valid for well sites and compressor stations.

The EPA exempted natural gas processing plants from LDAR requirements when issuing 40 CFR part 60, subpart KKK, in 1985 (1985 NSPS KKK). At that time, we acknowledged ''that there are several unique aspects to the operation of natural gas processing plants north of the Arctic Circle. Because of the unique aspects of natural gas processing plants north of the Arctic Circle, the increased costs to perform routine leak detection and repair may result in an unreasonable cost effectiveness.'' [73] We currently do not have sufficient information to suggest that the cost-effectiveness of the fugitive emissions requirements specific to well sites and compressor stations located on the Alaskan North Slope differ from the cost-effectiveness of the program generally. The information we do have related to the initial monitoring suggests that the average initial percentage of identified fugitive emissions for a well site located on the Alaskan North Slope is 2.38 percent.[74] Additionally, this information represents some of the highest reported percentages of identified fugitive emissions from the data set are from well sites located on the Alaskan North Slope. Therefore, we are not proposing to exempt well sites located on the Alaskan North Slope from the fugitive emissions requirements. However, we are soliciting data to support an analysis of the cost-effectiveness of fugitive emissions monitoring programs for well sites and compressor stations located on the Alaskan North Slope, including the cost associated with performing annual fugitive emissions monitoring and repairs. Specific information that distinguishes differences in cost realized by sites located on the Alaskan North Slope from our model plant estimates would be useful.

2. Modification

Modification of Well Sites. For the purposes of fugitive emissions components at a well site, a modification is defined in 40 CFR 60.5365a(i)(3) as (i) drilling a new well at an existing well site, (ii) hydraulically fracturing a well at an existing well site, or (iii) hydraulically refracturing a well at an existing well site. As the EPA explained in that rulemaking, these three activities, which are conducted to increase production, increase fugitive emissions at well sites in two ways. First, increased production will ''generate additional emissions at the well sites. Some of these additional emissions will pass through leaking fugitive emission components at the well sites (in addition to the emissions already leaking from those components).'' 81 FR 35881. Second, additional fugitive emissions can also result from installation of additional equipment. As the EPA observed, ''it is not uncommon that an increase in production would require additional equipment and, therefore, additional fugitive emission components at the well sites.'' *Id.*

As previously mentioned, in a letter dated April 18, 2017, the Administrator granted reconsideration of several

[72] See Docket ID No. EPA–HQ–OAR–2010–0505–7682.

[73] ''Equipment Leaks of VOC in Natural Gas Production Industry—Background Information for Promulgated Standards,'' EPA–450/3–82–024b, May 1985.

[74] See memorandum *EPA Analysis of Well Site Fugitive Emissions Monitoring Data Provided by API* located at Docket ID No. EPA–HQ–OAR–2017–0483. April 17, 2018.

aspects of the 2016 NSPS OOOOa, including its application of the fugitive emissions requirements at 40 CFR 60.5397a to low production well sites.[75] The petitioner who raised this issue for reconsideration identified in its petition a perceived inconsistency between the EPA's justification for not exempting low production well sites from the fugitive emissions requirements and the EPA's rationale for the definition of modification for purposes of those same requirements.[76] This petitioner observed that it appeared the EPA relied on data indicating the same equipment counts are present at all well sites, regardless of production levels, to justify regulating fugitive emissions at low production well sites, while defining modification by events that increase production (*i.e.,* drilling a new well, hydraulic fracturing, or hydraulic refracturing), which the EPA concludes will increase emissions whether or not there is change in component counts. The petitioner then stated that:

> EPA's rationale, that fugitive emissions are a function of the number and types of equipment, and not operating parameters such as pressure and volume, is inconsistent with EPA's justification for what constitutes a 'modification' for an existing well site. EPA assumes that fracturing or refracturing an existing well will increase emissions because of the additional production, *i.e.,* the additional pressure and volume. EPA cannot ignore the laws of physics to the detriment of low production wells in one instance and then 'honor' them in another context to eliminate an 'emissions increase' requirement in the traditional definition of 'modification.' [77]

In addition to the issues raised regarding an inconsistency with our treatment of fugitive emissions from low production well sites and what constitutes a modification (as discussed in section VI.B.1), several petitioners stated that hydraulically refracturing a well alone would not increase emissions from the fugitive emissions components and suggested that emissions would increase from a refractured well only if additional permanent equipment is also installed.[78] According to one petitioner,

> [a] well that is refractured typically does not require additional production equipment and does not typically operate at a pressure higher than before the refracturing since that pressure is set by the gas gathering system pressure. Therefore, as long as a significant piece of process equipment is not constructed along with the refracture, there is no emissions increase and there is no 'modification' as defined in CFR part 60.2. [79]

In light of the above, the EPA has provided a more detailed explanation below for the definition of modification of fugitive emissions components at well sites, including how an increase in production can increase fugitive emissions at well sites even without the addition of equipment, and therefore no addition of fugitive emissions components. The EPA has also re-evaluated its treatment of low production well sites, which is discussed in section VI.B.1 of this preamble.

There is no dispute that an addition of processing equipment, and attendant fugitive emissions components, in conjunction with refracturing a well will result in a modification. Further, as explained in the 2016 NSPS OOOOa and in more detail below, an increase in the number of components is not the sole reason for an increase in fugitive emissions when there is an increase in production.

A well is refractured for the purpose of increasing production rates. An increase in the production rate necessitates, by definition, an increase in the molar flow rate. An increase in molar flow rate can be accomplished through an increase in operating pressure (and attendant mass per unit of volume) and/or volumetric flow rate. An increase in volumetric flow rate can be accomplished through an increase to the velocity of flow, an increase to cross-sectional area of the flow path, or, if flow is intermittent, an increase to the time duration of flow (*e.g.,* duration of flow events or frequency of flow events). Increasing velocity of flow of production fluids through process equipment can only be accomplished through an increase in the pressure drop across the system. Where increased production throughput is routed through a system of production equipment that is not physically changed, the cross-sectional area of the flow path through the equipment does not change. Therefore, the increase in production rate requires an increase to either the operating pressure and/or the duration or frequency of flow events. Where operating pressure is increased, the pressure increase will increase the molar flow rate of fugitive emissions from leaking fugitive emission components. These increased emissions on components with existing fugitive emissions will occur even if the increased operating pressure does not result in additional components with fugitive emissions at existing design stress points, which is an additional source of potential fugitive emissions increases. Increasing duration or frequency of flow events will not be an option unless flow is intermittent. Where flow is intermittent in the process and flow event duration or frequency is increased (*e.g.,* through longer dump events or more frequent dump events), additional molar flow rate will pass through components with fugitive emissions due to increased periods of flow through that component at the same pressure. Therefore, as was stated in the 2016 NSPS OOOOa preamble language, increased production will result in ''[s]ome of these additional emissions [passing] through leaking fugitive emission components at the well sites (in addition to the emissions already leaking from those components).'' 81 FR 35881.

There is also a third instance in which increased production from modification of a well site could cause an increase in emissions from fugitive emissions components without additional equipment, and therefore, without additional fugitive emissions components. Absent additional stages of separation or an otherwise-accomplished decrease in the pressure at the final stage of separation prior to the storage vessels, increased production throughput to storage vessels increases the flash emissions at those storage vessels. Where storage vessels are affected facilities for purposes of this rule, the rule contains separate requirements for storage vessel covers and CVS to be designed and operated to route all emissions to a control device. However, where controlled storage vessels are not affected facilities because legally and practically enforceable permits limit the potential VOC emissions to below 6 tpy, the covers and CVS are included in the fugitives monitoring program for the well site as a fugitive emissions component. In either scenario, it is possible for increased throughput to these controlled storage vessels at a well site to exceed the design capacity of the vapor control system, which may result in additional emissions from storage vessel thief hatches or other openings.

For the reasons stated above, we propose to maintain our conclusion that refracturing of an existing well will increase fugitive emissions. We solicit comments on our rationale described above. Specifically, we solicit comments and data on whether emissions from fugitive emissions components will

[75] See Docket ID No. EPA–HQ–OAR–2010–0505–7730.

[76] See Docket ID No. EPA–HQ–OAR–2010–0505–7685.

[77] See Docket ID No. EPA–HQ–OAR–2010–0505–7685, page 6.

[78] See Docket ID Nos. EPA–HQ–OAR–2010–0505–7682, EPA–HQ–OAR–2010–0505–7685 and EPA–HQ–OAR–2010–0505–7686.

[79] Docket ID No. EPA–HQ–OAR–2010–0505–7682, p. 16.

increase following a refracture even if the equipment counts and operating pressures remain the same. Further, we are soliciting comments and data about how changes in production may influence the operating pressures of the well site. Additionally, we are soliciting comment and data on whether an increase in pressure alone (without additional equipment) would result in more fugitive emissions (*e.g.,* cause new fugitive emissions that were not otherwise present or would result in an increase in the fugitive emissions from an already leaking fugitive emissions component). Finally, we are soliciting comment and information on other factors, such as changes in the gas gathering system, that may influence the operating pressures of the well site.

During the implementation of the 2016 NSPS OOOOa, several questions were raised regarding the modification of a separate tank battery for the purposes of fugitive emissions monitoring. The definition of well site in 40 CFR 60.5430a states, ''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).'' Stakeholders have commented to the EPA that there is confusion regarding when a modification of fugitive emissions components has occurred at a separate tank battery. Similar to the information from petitioners regarding modifications without a change in equipment or component counts at a well site, stakeholders have also claimed that sending process fluids from a new well or existing hydraulically fractured or refractured well that is not located at the separate tank battery will not necessarily increase the emissions from the fugitive emissions components at the separate tank battery. Instead, stakeholders have suggested that emissions increase only when additional processing equipment, such as storage vessels, separators, or compressors, is installed in conjunction with the introduction of additional process fluids received from these off-site wells.

The EPA is proposing a clarification to address modifications of the collection of fugitive emissions components at well sites when the well site is a separate tank battery with no wells located at the tank battery. While the regulatory text is clear about what constitutes a modification when a well is located at the separate tank battery, the regulatory text is less clear when there are no wells at the tank battery. To clarify the definition of modifications for separate tank batteries, we are proposing specific amendments to clarify when a modification occurs at a well site, including a well site that is a separate tank battery. We are proposing to amend the language in 40 CFR 60.5365a(i) to add two additional instances to clarify when there is a modification to the collection of fugitive emissions components located at a separate tank battery, such as a centralized tank battery (which itself is a well site as defined in 40 CFR 60.5430a). First, when production from a new, hydraulically fractured, or hydraulically refractured well is sent to an existing separate tank battery, the collection of fugitive emissions components at the separate tank battery has been modified. Second, when a well site that is subject to fugitive emissions requirements removes the major production and processing equipment, such that it becomes a well head only well site, and sends the production to an existing separate tank battery, the collection of fugitive components at that separate tank battery has modified. In both instances, a physical or operational change occurs at an existing separate tank battery because additional production from a well site is sent to that separate tank battery, and this change results in an increase in fugitive emissions at that tank battery. We are soliciting comment on these proposed amendments to the definition of modification of the collection of fugitive emissions components located at a well site, including the treatment of separate tank batteries as well sites for the purposes of fugitive emissions requirements. Additionally, we are soliciting comment on other options for modifications of a separate tank battery for purposes of fugitive emissions monitoring. For example, we are soliciting comment on whether we should define a separate tank battery as a separate affected facility, instead of defining this source as a well site. Further, we are soliciting comment on what would constitute a modification of a separate tank battery affected facility, or other options for a modification if the definition remains as currently proposed. Finally, the EPA is soliciting information related to the permitting of such separate tank batteries and information related to how states have regulated these sources when a well is not located at the site.

Modification of Compressor Stations. For the purposes of fugitive emissions components at a compressor station, a modification is defined in 40 CFR 60.5365a(j) as (1) the installation of an additional compressor at an existing compressor station or (2) the replacement of one or more compressors at an existing compressor station that results in a net increase in the total horsepower to drive the compressor(s) that are replaced at the compressor station. We are not proposing any changes to this definition; however, we are soliciting comment on whether the engine horsepower is the correct measure of increased emissions from the collection of fugitive emissions components.

Further, the EPA is clarifying the type of compressors that would trigger a modification for the purposes of fugitive emissions at a compressor station. In the preamble to the 2016 NSPS OOOOa, the EPA clarified that this definition refers to instances where ''the design capacity and potential emissions of the compressor station would increase.'' 81 FR 35864. Therefore, it is possible that the addition of a compressor would not be considered a modification where the overall design capacity of the compressor station is not increased. For example, the addition of a vapor recovery unit (VRU) compressor, such as a screw or vane compressor, would not be a modification for purposes of the compressor station fugitive emissions standards. Adding a VRU compressor does not increase the overall design capacity of the compressor station for the following reasons. VRU compressors are installed to recover methane and VOC emissions; they are not designed to ''move natural gas at increased pressure through gathering or transmission pipelines, or into or out of storage.'' Therefore, the addition of a VRU compressor does not increase the overall design capacity of a compressor station, and does not result in a modification of the compressor station for the purposes of fugitive emissions monitoring. The EPA is not proposing a definition for compressor in this action because the explanation provided above related to the definition of compressor station does not support the need for a definition, and because the 2016 NSPS OOOOa already contains definitions of centrifugal and reciprocating compressors, which are the only compressor affected facilities.

3. Initial Monitoring for Well Sites and Compressor Stations

The 2016 NSPS OOOOa requires completion of initial monitoring for well sites and compressor stations by June 3, 2017, or 60 days after startup, whichever is later. For well sites, the startup of production marks the beginning of the initial monitoring survey period for the collection of fugitive emissions components at a well site. Similarly, for compressor stations, the startup of the compressor station marks the beginning of the initial monitoring survey period.

Petitioners on the 2016 NSPS OOOOa have requested that the timing of fugitive emissions initial monitoring surveys be revised to allow for integration into existing monitoring programs.[80] One petitioner asserted that there are numerous challenges to setting up and implementing a fugitive monitoring program. The petitioner reported that even with the EPA's one-year phase-in allowance, there are initial inspection timing challenges (*e.g.,* because of the significant distances between oil and gas sites). Petitioners requested that the EPA consider allowing 180 days for the initial survey. According to the petitioners, allowing for 180 days would not result in significantly more emissions and that, on average, half of the sites would likely conduct their initial survey in less than 90 days and half would likely conduct their initial survey between 90 and 180 days.

Between proposal and promulgation of the 2016 NSPS OOOOa, several industry comments recommended a 90-day time period (in lieu of the 30-day time period we initially proposed) to complete the initial survey to (1) address time and logistical capacities of oil and gas field crews and potential limited availability of monitoring contractors, (2) be consistent with the Ohio Environmental Protection Agency's General Air Permit for Oil and Gas Well Site Production Operations (General Permit 12.2), and (3) provide a more realistic time frame to perform an initial survey without potentially resulting in safety issues while initial oil and gas production and completion activities are taking place on the well pad.[81] Other industry comments were received requesting that the EPA allow the initial fugitive survey to occur within 180 days from startup of a new well site or compressor station to (1) be consistent with similar LDAR programs, such as NSPS KKK and NSPS OOOO (where leak detection is currently imposed at natural gas processing plants), and (2) allow owners or operators time to do a thorough check of all new equipment installations before the survey.[82] One of the commenters (also a petitioner) reported that 180 days is needed to prepare for monitoring of the new or modified well site and ensure that such monitoring is conducted during the next scheduled monitoring period that would include all the well sites in the area.[83] They asserted that hiring third-party contractors to monitor one remote well site is inefficient and costly.

We have not received data indicating that initial monitoring cannot be completed within the currently required 60-day timeframe. We propose to maintain our conclusion that, in light of the need to complete initial monitoring in a timely manner after startup of production for well sites and the startup or modification for compressor stations to verify the proper installation of equipment, waiting 180 days for initial monitoring is too long after the installation of equipment to verify its proper installation. However, we are soliciting data that supports or refutes the claims by the petitioner that 180 days are necessary for proper installation of equipment before conducting initial monitoring would not result in significantly more emissions. Assuming we receive information that supports extending the initial monitoring deadline to give more time for installing equipment, we think it is possible these tasks may be nevertheless completed in a shorter time frame than the suggested 180 days discussed above. We are, therefore, soliciting comment and supporting data for changing the initial monitoring deadline to 90 days from 60 days after the startup of production for well sites and the startup or modification for compressor stations. Specific data would need to outline the difficulties with completing initial monitoring within the 60 days required in the 2016 NSPS OOOOa. In summary, while we are proposing to maintain the 60-day requirement, we solicit comment and information regarding the request to extend to 180 days, as well as an intermediate 90-day requirement.

We recognize that the 2016 NSPS OOOOa includes a waiver from quarterly monitoring at compressor stations after recognizing there are areas of the country that may experience temperatures below 0° for a period of 60 days. However, as discussed in detail in section VI.B.4, we are not sure where any areas of the country would utilize this waiver. The EPA is soliciting comment on how cold weather may impact the ability to comply with the 60-day initial monitoring deadline for well sites and compressor stations.

4. Low Temperature Waivers

In the 2016 NSPS OOOOa, owners and operators are granted a waiver from one quarterly monitoring event at compressor stations if the average temperature is below 0° for two consecutive quarters. 40 CFR 60.5397a(g)(5). In the preamble to the 2016 NSPS OOOOa we stated that the waiver was included for two reasons: (1) There were concerns raised by commenters that extreme winter weather created risk for the safety of monitoring survey personnel and (2) the manufacturer specifications indicate that OGI cameras may not reliably operate at temperatures below 0°. 80 FR 56668. In light of the proposed changes to monitoring frequencies discussed in section VI.B.1 of this preamble, we are proposing to remove the low temperature waiver because it is no longer relevant. The EPA is soliciting comment and supporting data that would indicate a need to maintain the waiver.

5. Repair Requirements

Repair. After detection of fugitive emissions, the 2016 NSPS OOOOa requires repair of these components within 30 days of detection of the fugitive emissions. Further, the owner or operator must resurvey the component within 30 days of the repair in order to verify successful repair. 40 CFR 60.5397a(h)(1) and (3).

Several questions were raised during implementation that required reconsideration of the repair requirements. Specifically, stakeholders asked about the situation where repairs were completed during the 30-day required timeframe but the resurvey identified the presence of fugitive emissions, indicating unsuccessful repair.

The EPA recognizes the requirements in the 2016 NSPS OOOOa may create an unintended noncompliance issue with the repair requirements. Therefore, we are proposing to amend the repair requirements to require a ''first attempt at repair'' within 30 days of detection of fugitive emissions, followed by a requirement that identified fugitive emissions be ''repaired'' within 60 days of detection. We are proposing definitions for ''repaired'' and ''first attempt at repair'' as related to the fugitive emissions requirements. The EPA is proposing to define ''repaired,'' for purposes of fugitive emissions monitoring, as ''fugitive emissions components are adjusted, replaced, or otherwise altered, in order to eliminate fugitive emissions as defined in 40 CFR 60.5397a of this subpart and is

[80] See Docket ID Nos. EPA–HQ–OAR–2010–0505–7682 and EPA–HQ–OAR–2010–0505–10791.

[81] See Docket ID Nos. EPA–HQ–OAR–2010–0505–6808, EPA–HQ–OAR–2010–0505–6935 and EPA–HQ–OAR–2010–0505–6960.

[82] See Docket ID EPA–HQ–OAR–2010–0505–6857.

[83] See Docket ID EPA–HQ–OAR–2010–0505–6884.

resurveyed as specified in 40 CFR 60.5397a(h)(4) and it is verified that emissions from the fugitive emissions components are below the applicable fugitive emissions definition.'' Additionally, we are proposing the definition for ''first attempt at repair'' for the purposes of fugitive emissions monitoring as ''an action taken for the purpose of stopping or reducing fugitive emissions of methane or VOC 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; ensuring the thief hatch is properly seated or injecting lubricant into lubricated packing.'' These proposed definitions for ''repaired'' and ''first attempt at repair'' are specific to the fugitive emissions requirements and would not replace the definitions for ''repaired'' or ''first attempt at repair'' within the requirements for equipment leaks at onshore natural gas processing plants referenced in 40 CFR part 60, subpart VVa. We are soliciting comment on these proposed repair requirements and definitions.

Delay of Repair. As amended on March 12, 2018, the 2016 NSPS OOOOa allows for delay of repair if the repair is technically infeasible; requires 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. Repairs meeting one of these criteria must be completed during the next scheduled compressor station shutdown, well shutdown, or well shut-in; after a planned vent blowdown; or within 2 years, whichever is earlier. The amendment addressed the concerns associated with requiring repair during unscheduled or emergency events by removing such a requirement.

In addition to concerns with requiring repair during unscheduled or emergency events, several petitioners raised additional concerns with the provisions regarding the delay of repair for fugitive emissions components at well sites and compressor stations.[84] One petitioner stated that the 2-year delay should be reevaluated because no specific data was provided to support that deadline.[85] Further, other petitioners stated that blowdowns, shutdowns, and well shut-ins might not always involve depressurizing the specific equipment that needs repair. The EPA is soliciting comment on instances when equipment cannot be isolated during vent blowdowns, compressor station shutdowns, well shutdowns, and well shut-ins to allow for repair of components with fugitive emissions. Further, the EPA is soliciting comment and supporting information on the instances where delayed repairs cannot be conducted during any of the events listed in the rule and under what event or time frame delayed repairs can be conducted for those instances.

Finally, we are clarifying when a repair can be delayed. There are three circumstances when repair can be delayed: (1) When the repair is technically infeasible, (2) when the repair requires a vent blowdown, a compressor station shutdown, a well shut-in, or a well shutdown, and (3) when the repair is unsafe during operation of the unit.[86] The 2016 NSPS OOOOa requires an explanation of each repair that is delayed as well.[87] As discussed in section VI.B.1, we have added 1 controlled storage vessel per model plant because when the controlled storage vessel is not subject to the control requirements in 40 CFR 60.5395a, the thief hatch and other openings are subject to fugitive emissions requirements, per the definition of fugitive emissions components in 40 CFR 60.5430a. The EPA believes that thief hatches on controlled storage vessels which are part of the fugitive emissions program would not be subject to delay of repair under any of these circumstances; however, we are soliciting comment for any instance when delaying repair on a thief hatch may be necessary. The EPA acknowledges that questions may arise as to whether opening a thief hatch is considered a vent blowdown. While we do not consider this to constitute a vent blowdown, we are soliciting comment on whether clarification within the regulatory text is necessary for this point. We are also soliciting comment on the 2-year deadline for completion of delayed repairs.

6. Definitions Related to Fugitive Emissions at Well Sites and Compressor Stations

Third-party equipment. In the 2016 NSPS OOOOa, all fugitive emissions components located at a well site, regardless of ownership, are subject to the monitoring and repair requirements for fugitive emissions in the 2016 NSPS OOOOa. As defined in 40 CFR 60.5430a, the term 'fugitive emissions component' means ''any component that has the potential to emit fugitive emissions of methane or VOC at a well site or compressor station, including, but not limited to valves, connectors, pressure relief devices, open-ended lines, flanges, covers and closed vent systems not subject to § 60.5411a, thief hatches or other openings on a controlled storage vessel not subject to § 60.5395a, compressors, instruments, and meters'' and the term '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.'' Several petitioners raised concerns that these definitions are too broad and requested that the EPA should exclude equipment that is owned and operated by a third-party.[88]

First, petitioners requested an exemption for equipment owned and operated by midstream companies because that equipment is owned by legally distinct entities, and applicability of the standards to midstream assets would be based solely on the actions of the upstream producers. Second, petitioners stated that the EPA is incorrect in suggesting that contractual agreements between upstream producers and midstream owners and operators would be appropriate for managing fugitive emissions monitoring and repair(s) at the well site. The petitioners stated that, due to the complexity of contractual agreements between different owners and operators at a well site, each individual owner or operator may need to develop and implement separate fugitive emissions monitoring programs. The petitioner further stated that doing so would add significant and unnecessary costs that the EPA did not consider.[89]

In the response to comment document for the 2016 NSPS OOOOa we stated that cooperative agreements could be used to resolve any fugitive emissions identified during surveys, but we acknowledged in the 2017 NODA that confusion remained over the applicability of the fugitive emissions requirements as they relate to ancillary midstream assets that are owned by companies that are legally distinct from the well site owner and operator and that could have limited emissions. 82 FR 51798. In their comments on the 2017 NODA, one petitioner noted that since the components associated with the gas gathering and metering systems

[84] See Docket ID Nos. EPA–HQ–OAR–2010–0505–7682, EPA–HQ–OAR–2010–0505–7683, and EPA–HQ–OAR–2010–0505–7686.

[85] See Docket ID No. EPA–HQ–OAR–2010–0505–7683.

[86] See 40 CFR 60.5397a(h)(2).

[87] See 40 CFR 60.5420a(b)(7)(ii)(J).

[88] See Docket ID Nos. EPA–HQ–OAR–2010–0505–7682 and EPA–HQ–OAR–2010–0505–7684.

[89] See Docket ID No. EPA–HQ–OAR–2010–0505–7684.

serve the ''crucial commercial purpose in calculating gas accepted by the gathering company and the related revenue accounting,'' the midstream operators could not allow the production operators to access this equipment.[90] This petitioner further clarified that due to this limitation, the midstream operator would need to implement a separate fugitive emissions program for a limited number of components. Additionally, the petitioner stated there are significant practical issues with renegotiating contracts, especially as well sites are modified over time. We did not consider this issue during development of the 2016 NSPS OOOOa.

In light of the concerns raised by the petitioners, the EPA is proposing to amend the definition of ''well site,'' for the purposes of fugitive emissions monitoring, to exclude the flange upstream of the custody meter assembly, and fugitive emissions components located downstream of this flange. The EPA understands this custody meter is used effectively as the cash register for the well site and provides a clear separation for the equipment associated with production of the well site, and the equipment associated with putting the gas into the gas gathering system. Additionally, the proposed definition would exclude only a small number of fugitive emissions components, and we do not believe it would be cost-effective to require a separate fugitive emissions program for these components. We are also proposing a definition for the 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.'' We are limiting the exemption within the definition of a well site to the flange upstream of the custody meter because we are not aware of similar issues with monitoring other third-party equipment at a well site. The EPA is soliciting comment on this proposed change to the ''well site'' definition, the proposed definition of ''custody meter,'' the proposed definition of ''custody meter assembly,'' and suggestions for other ways which provide a clear separation to distinguish the third-party equipment described above at a well site, for the purposes of fugitive emissions monitoring.

Applicability to Saltwater Disposal Wells. In addition to concerns about the definition of a ''well site'' as it relates to third party equipment, the EPA received feedback from industry seeking confirmation that a saltwater disposal well is not an injection well as the term is used in the definition for well site and, therefore, not subject to the fugitive emission standards at 40 CFR 60.5397a. They asserted that disposal wells are not injection wells and that the disposed liquid consists of water with insignificant amounts of stabilized skim oil that is never in vapor state at normal or elevated conditions. The commenters were concerned that, although they did not believe it was the EPA's intent to require fugitive emissions monitoring of saltwater disposal wells, they will nevertheless have to comply with those requirements because, as written, the definition of ''well site'' is ambiguous with respect to the status of saltwater disposal wells.

Deposits of oil and natural gas can be found in porous rocks and shale, where saltwater is also found. Oil and gas pumped out of the earth that is not pure enough for distribution because of saltwater and other chemicals/impurities go through a separation phase or are treated with chemicals that extract the impurities. After the oil or gas is treated, the water that remains (referred to as ''saltwater'') is subject to handling requirements.[91] Saltwater, or produced water, that results from bringing the oil and gas up to the surface (ejected from the well) during production operations is generally (1) recycled, (2) returned to the reservoir for fluid reinjection or (3) injected into underground porous rock formations not productive of oil or gas, and sealed above and below by unbroken, impermeable strata.[92] The third option is considered saltwater disposal (or oilfield wastewater disposal). Regulations for the disposal of this water vary from state to state, but the EPA monitors disposal to ensure ground water is not contaminated through Underground Injection Control (UIC) programs under the federal Safe Drinking Water Act for surface and groundwater protection. The EPA had not considered these UIC Class II oilfield wastewater disposal wells during the development of the fugitive emissions standards in the 2016 NSPS OOOOa.

For the reasons stated below, we are proposing to exclude UIC Class II oilfield wastewater disposal wells from the well site definition and are proposing a definition for a UIC Class II oilfield wastewater disposal well to distinguish them from injection wells subject to the rule. It is our understanding that the storage vessels located at these disposal facilities have low methane and VOC emissions, and thus are not subject to the control requirements for storage vessels found in 40 CFR 60.5395a, do not require controls for permitting purposes, and would not be subject to fugitive emissions monitoring because they are uncontrolled. Further, it is our understanding that the number of fugitive emissions components at these facilities are typically low, including water pumps and a limited number of valves or connectors, which are expected to have negligible if any fugitive emissions. These proposed changes clarify the universe of well sites subject to the fugitive emissions standards. Our proposed definition for a ''UIC Class II oilfield 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.'' Further, we are proposing that 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. We are soliciting comment on this proposed definition and on the proposed exemption for UIC Class II wastewater disposal wells and disposal facilities from fugitive emissions monitoring and repair, including data to support or refute our understanding that these sites have limited fugitive emissions components.

Definition of well site. As discussed in the sections regarding third-party equipment and saltwater disposal wells, the EPA is proposing to amend the definition of well site as follows:

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 fugitive emission standards at § 60.5397a, a well site also means a separate tank battery surface site collection 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 and (2) the flange upstream of the custody meter

[90] See Docket ID No. EPA–HQ–OAR–2010–0505–13436.

[91] *http://www.tech-flo.net/salt-water-disposal.html.*

[92] Barnett Shale Energy Education Council. *What are Saltwater Disposal Wells*? Air and Water Quality. *http://www.bseec.org/what_are_saltwater_disposal_wells.*

assembly and equipment, including fugitive emissions components, located downstream of this flange.

Startup of Production. The EPA defines the ''startup of production'' in the 2016 NSPS OOOOa 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.'' 40 CFR 60.5430a. For purposes of the fugitive emissions requirements in 40 CFR 60.5397a, the initial monitoring survey follows the startup of production. We received questions from stakeholders that suggested this definition would limit the fugitive emissions requirements to well sites with hydraulically fractured wells and not those with conventional wells. While the first trigger for modification is based on the drilling of a new well, regardless if it is hydraulically fractured or not, the definition of startup of production is linked to flowback, which is inherently an effect following hydraulic fracturing.

We are proposing to amend the definition of ''startup of production'' in this proposal to address how it relates to the fugitive emissions requirements. Specifically, we are proposing that, for the purposes of the fugitive monitoring requirements, 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.'' We are soliciting comment on this proposed definition change as it relates to wells that are not hydraulically fractured.

7. Fugitive Emissions Monitoring Plan

The 2016 NSPS OOOOa requires that each fugitive emissions monitoring plan include a sitemap and a defined observation path.[93] As we are clarifying in this proposed action, these requirements were meant to apply only to owners and operators using OGI for monitoring surveys, not to owners and operators using Method 21. In addition to clarifying this intent, we are also proposing options that owners and operators using OGI for monitoring surveys can comply with in lieu of the observation path requirement.

As we discussed in the preamble to the 2016 NSPS OOOOa, the purpose of the observation path is to ensure that the OGI operator visualizes all of the components that must be monitored. In a traditional monitoring scenario using Method 21, the owner or operator tags all of the equipment that must be monitored, and when the operator subsequently inspects the affected facility, the operator scans each component's tag and notes the component's instrument reading. The EPA realizes that this is a time-consuming practice that requires close contact with each component, whereas with OGI, the operator can be away from the components and still monitor several components simultaneously. The observation path [94] was intended to offer owners and operators an alternative to the traditional tagging approach while still providing assurance that the owner or operator has met the obligation to monitor all components. 81 FR 35860.

Petitions received on the 2016 NSPS OOOOa assert that there is no added benefit to including the sitemap and defined observation path in the fugitive emissions monitoring plan and that they should be removed.[95] Industry representatives report that, in many cases, sitemaps do not exist. They further report that there are significant added costs associated with the requirement to develop site-specific details for a sitemap and a defined observation path for each site and that there may be hundreds to thousands of different sites. These representatives express concern that sitemaps could also change, subjecting them to additional costs associated with revising the fugitive emissions monitoring plan without any added benefit. While we do think that it is necessary to revise monitoring plans when equipment at the site changes,[96] we generally expected these to be one-time requirements, unless additional equipment is added to the site. 81 FR 35860. The EPA is specifically seeking comment on whether this assumption is incorrect and, if not, we solicit information on the cost to develop and revise the sitemap, including the cost to document an observation path, the cost to revise a sitemap and observation path, and the frequency with which the sitemap and observation path need to be updated. We are also clarifying that plot plans can be substituted for sitemaps, as these two items serve the same function, *i.e.,* to provide information on the locations of equipment on site.

Industry representatives have also expressed concern that the fugitive emissions monitoring plan as written in 40 CFR 60.5397a(d) may cause enforcement issues in cases where the fugitive emissions monitoring plan is not followed exactly (specifically related to the defined observation path), even when the deviation is not critical and the monitoring plan is still effective. In response to public comments on the 2016 NSPS OOOOa, we stated that the elements required in the monitoring plan are necessary to judge the quality of the fugitive emissions survey, in light of the fact that the EPA does not have a standard method for use of OGI, but that we fully expected a trained and experienced camera operator to know when deviations from the standard monitoring plan are necessary and to make these deviations.[97] However, while deviations may not impact the camera's detection ability and can actually improve the detection ability, this does not mean that deviations from the monitoring plan should not be noted because this record provides valuable information to air agency reviewers on how surveys are conducted and whether the deviations from the monitoring plan are adequate and warranted. We note that deviations from the monitoring plan are not necessarily deviations from the requirements of the rule.

While we are not proposing to remove the sitemap and observation path elements from the fugitive emissions monitoring plan, we are proposing two alternatives to address petitioner/industry representative concerns. First, in lieu of the defined observation path, we are proposing to add language to 40 CFR 60.5397a(d) that allows an owner or operator to describe how each type of equipment will be effectively monitored, including a description and location of the fugitive emissions components located on the equipment. The sitemap would include the locations of the pieces of equipment when complying with this option. Second, in lieu of meeting the sitemap and defined observation path requirements, we are proposing to add language to 40 CFR 60.5397a(d) to extend the inventory requirement that is currently in 40 CFR 60.5397a(d)(3) for when an owner or operator chooses to perform a survey with Method 21 as an option for owners and operators who perform surveys with OGI. We believe

[93] See 40 CFR 60.5397a(d)(1) and (2).

[94] In the preamble to the 2016 NSPS OOOOa, we also noted that the purpose of using the term ''observation path'' was to clarify that the emphasis is on the field of view of the OGI instrument, not the physical location of the OGI operator. 81 FR 35860.

[95] See Docket ID Nos. EPA–HQ–OAR–2010–0505–7686 and EPA–HQ–OAR–2010–0505–10791.

[96] As we stated in the preamble to the 2016 NSPS OOOOa, we do not expect facilities to create overly detailed process and instrumentation diagrams to describe the observation path. The observation path description could be a simple schematic diagram of the facility site or an aerial photograph of the facility site, as long as such a photograph clearly shows locations of the components and the OGI operator's walking path. 81 FR 35860.

[97] See Docket ID No. EPA–HQ–OAR–2010–0505–7632, Chapter 4, page 4–708.

that both of these options provide assurances similar to the observation path that the owner or operator meets the requirement to visualize all components.

In summary, the EPA is retaining the requirements for the sitemap and observation path in the fugitive monitoring plan, but is also proposing two alternatives to these requirements. The EPA is soliciting comment on these proposed alternatives. Additionally, we are soliciting comment on other potential options that would serve the same functions as an observation path and sitemap. We are particularly interested in potential options that provide assurance that all regulated components have been monitored, how this information can be documented, and the costs of such alternative approaches.

C. Professional Engineer Certifications

The 2016 NSPS OOOOa requires that CVS used for routing emissions from centrifugal compressor wet seal fluid degassing systems, reciprocating compressors, pneumatic pumps, and storage vessels must have sufficient design and capacity to ensure that all emissions are routed to the control device. 40 CFR 60.5411a(d). This is accomplished through a design evaluation that must be certified by a ''qualified professional engineer'' (PE). Several petitioners requested reconsideration of the PE certification requirement because the EPA did not provide an evaluation of the costs associated with the certification.[98] Additionally, petitioners requested that the EPA allow alternatives to PE certification, such as engineering design reviews not necessarily conducted by a licensed PE.

The 2016 NSPS OOOOa also includes a technical infeasibility provision allowing an exemption from the well site pneumatic pump requirements. However, the rule requires that such technical infeasibility be determined and certified by a ''qualified professional engineer.'' 40 CFR 60.5393a(b)(5)(i). Petitioners objected to this additional certification, stating it results in additional costs and project delays, with no environmental benefits. Additionally, petitioners questioned the value of this requirement, claiming it is duplicative with the existing general duty obligations and requirement to provide a certifying official's acknowledgment. Petitioners also stated that few companies have a sufficient number of in-house PEs, and requested that this requirement be broadened to allow alternatives to PE certification, including requiring engineering review and approval of all designs.

In the 2017 NODA, we requested information related to the availability of PEs to provide these certifications. Seven commenters provided information. Three commenters stated that there should be no limitation related to the availability of licensed PEs because in 2016 over 400,000 resident licenses were issued, and over 400,000 non-resident licenses were issued (a PE can hold both types of licenses).[99] One commenter cited a similar requirement in Colorado's regulation and stated that in response to the same concerns from the industry, Colorado found there was no basis for the claims about a lack of availability of PEs.[100] In contrast, four commenters stated difficulties with locating a PE willing to provide the certification, citing multiple concerns, including the certification statement included in the 2016 NSPS OOOOa and the certification of a portion of a system when the PE did not design the entire system.[101]

We have evaluated the concerns raised by petitioners regarding the additional burden of the PE certification for CVS design and pneumatic pump technical infeasibility. Further, the EPA agrees with commenters that in-house engineers may be more knowledgeable about site design and operation for both CVS and pneumatic pumps. In addition, the EPA acknowledges that, in the 2016 NSPS OOOOa, we did not analyze the costs associated with the PE certification requirement or evaluate whether the improved environmental performance this requirement may achieve justifies the associated costs and other compliance burden. In this action, the EPA evaluated the costs associated with PE certification and certification by an in-house engineer. We estimated costs based on two scenarios: (1) Requiring a PE certify the design and (2) allowing either a PE or an in-house engineer certify the design. We estimate that each PE certification would cost $547, while allowing use of in-house engineers would cost $358.[102] The EPA is soliciting comment on this cost estimate.

After reconsideration of these costs, the EPA is proposing to amend the certification requirements for CVS design and technical infeasibility for pneumatic pumps. Specifically, we are proposing to allow certification by either a PE or an in-house engineer with expertise on the design and operation of the CVS or pneumatic pump. We believe that an in-house engineer with knowledge of the design and operation of the CVS is capable of performing these certifications, regardless of licensure; however, we are soliciting comment on the use of other engineers with knowledge of the design and operation of the CVS that may be appropriate for this certification, such as third-party or other qualified engineers. We continue to have a concern regarding the use of undersized or under designed CVS, which can result in pressure relief events from thief hatches and PRVs on the controlled storage vessels or CVS, thus allowing emissions to escape to the atmosphere uncontrolled. As stated in the 2013 NSPS OOOO Oil and Natural Gas Sector: Reconsideration of Certain Provisions of New Source Performance Standards, ''Improper design or operation of the storage vessel and its control system can result in occurrences where peak flow overwhelms the storage vessel and its capture systems, resulting in emissions that do not reach the control device, effectively reducing the control efficiency. We believe that it is essential that operators employ properly designed, sized, and operated storage vessels to achieve effective emissions control.'' 78 FR 22136. This proposed amendment will still ensure these systems are evaluated and certified by engineers with expert knowledge of their operation.

D. Alternative Means of Emission Limitation (AMEL)

The 2016 NSPS OOOOa contains provisions for owners and operators to request an AMEL for specific work practice standards in the rule, covering well completions, reciprocating compressors, and the collection of fugitive emissions components at well sites and compressor stations. An owner or operator can request an AMEL by submitting data that demonstrate the alternative will achieve at least equivalent emission reductions as the requirements in the rule, among other requirements such as initial and on-going compliance monitoring. The specific requirements for this request are outlined in 40 CFR 60.5398a. For the 2016 NSPS OOOOa, these alternatives

[98] See Docket ID Nos. EPA–HQ–OAR–2010–0505–7682, EPA–HQ–OAR–2010–0505–7685 and EPA–HQ–OAR–2010–0505–7686.

[99] See Docket ID Nos. EPA–HQ–OAR–2010–0505–12386, EPA–HQ–OAR–2010–0505–12441, and EPA–HQ–OAR–2010–0505–12469.

[100] See Docket ID No. EPA–HQ–OAR–2010–0505–12469.

[101] See Docket ID Nos. EPA–HQ–OAR–2010–0505–12422, EPA–HQ–OAR–2010–0505–12424, EPA–HQ–OAR–2010–0505–12437, and EPA–HQ–OAR–2010–0505–12446.

[102] See the TSD for additional discussion of certification cost.

could be based on emerging technologies (*e.g.,* for fugitive emissions, technologies other than OGI or Method 21) or requirements under state or local programs.

We are proposing to amend the language in 40 CFR 60.5398a for incorporation of emerging technologies, and to add a separate section at 40 CFR 60.5399a to take into account existing state programs as discussed in further detail in the sections below.

1. Incorporating Emerging Technologies

As discussed in the 2016 NSPS OOOOa, the EPA recognizes that new technologies are expected to enter the market in the near future that will locate the source of emissions sooner and at lower levels than current technology. While the EPA established a foundation for approving the use of emerging technologies in the final rule, several stakeholders have identified a need to streamline the process for requesting and approving an AMEL for individual affected sources, such as well completions, compressors, and the collection of fugitive emissions components located at a well site or at a compressor station. As promulgated in the 2016 NSPS OOOOa, each AMEL request must be submitted using site-specific information, which could result in the same owner or operator submitting identical requests for multiple affected facilities. We are clarifying that an individual application may include the same technology for multiple sites, provided the required information is provided for each site and any site-specific variations to the procedures are addressed in the application. The application must provide a demonstration of equivalency and the emission reductions achieved for each site included in the application. The EPA is also proposing specific changes to the AMEL process as it relates to emerging technologies to address this issue. Specifically, we are proposing to allow owners or operators to apply for an AMEL, on their own or in conjunction with manufacturers or vendors, and trade associations, that incorporates the use of alternative technologies, techniques, or processes, along with compliance monitoring provisions to ensure continuous compliance other than those identified in the 2016 NSPS OOOOa work practice standards. We are not changing the requirement that AMELs must be site-specific because we are aware of the variability of this sector and are concerned that the procedures for a specific technology may need to be adjusted based on site-specific conditions (*e.g.,* gas compositions, allowable emissions, or landscape). Therefore, we expect that applications for these AMEL will include site-specific procedures for ensuring continuous compliance of the emission reductions to be demonstrated as equivalent. For this reason, we are not proposing to allow a manufacturer, vendor, or trade association to apply for an AMEL without an owner or operator. However, we are soliciting comment on whether groups of sites within a specific area (*e.g.,* basin-specific) that are operated by the same operator could be grouped under a single AMEL. Additionally, we are proposing that field data can be supplemented with test data, modeling analyses and other documentation, provided the field data still provides information related to seasonal variations. For the purposes of fugitive emissions requirements, the application must demonstrate that the technology is able to detect emissions beyond those allowed, such as pneumatic controllers. We are soliciting comment on the proposed revisions to the application requirements for technology-based AMEL.

2. Incorporating State Programs

In addition to recognizing potential emerging technologies, the EPA evaluated existing state and local fugitive emissions programs during the development of the 2016 NSPS OOOOa for purposes of establishing AMEL. The EPA was unable to conclude that any state program as a whole would reflect what we identified as BSER in the 2016 NSPS OOOOa due to the differences in the sources covered and the specific requirements. However, the 2016 NSPS OOOOa allowed owners and operators to use the AMEL process to allow use of existing state or local programs. 81 FR 35871. Petitioners and states have raised specific questions about the practicality of the AMEL process as it relates to the incorporation of state programs.[103] For instance, one state has notified the EPA that since the ability to make an AMEL request is limited to owners and operators at the individual site level, it is possible that the EPA would have over 300 identical applications from various owners and operators wanting to use the same state program at their affected facilities. Believing that there may be opportunities to streamline the process, ensure compliance, and reduce regulatory burdens, the EPA continued its evaluation of existing state fugitive emissions programs after promulgating the 2016 NSPS OOOOa. Based on this evaluation, the EPA is proposing certain existing state requirements as alternatives to specified aspects (*e.g.,* monitoring, repair, and recordkeeping) of the fugitive emissions requirements for well sites and compressor stations.

To date, the EPA has evaluated 14 existing state programs for comparable or equivalent standards related to the fugitive emissions requirements in 40 CFR 60.5397a and the specific amendments in this proposal. For this evaluation, we compared the fugitive emissions components covered by the state programs, monitoring instruments, leak or fugitive emissions definitions, monitoring frequencies, repair requirements, and recordkeeping to the fugitive emissions requirements proposed in this action.[104] We did not include an evaluation of monitoring plans or reporting requirements because we are not proposing any alternative standards for these aspects of the fugitive emissions requirements. Through this evaluation, we have identified aspects of certain existing state fugitive emissions programs that we propose to find to be at least equivalent to the proposed amendments in this action.[105] For instance, we have evaluated the lists of affected fugitive components, monitoring instrument(s), fugitive definition(s), monitoring frequency, repair deadlines, delay of repair provisions, and recordkeeping of the programs reviewed. In most of the programs, the affected fugitive components were different than our definition of fugitive emissions component. Therefore, we are proposing alternative standards that also require the owner or operator to survey our entire list of fugitive emissions components, regardless of whether they are affected components in the state program. Additionally, we evaluated monitoring instruments, frequencies, and fugitive definitions in conjunction with each other. Where monitoring is more frequent, we are proposing that a different fugitive definition could be appropriate. For instance, the standards in the California Code of Regulations, title 17, sections 95665–95667 require quarterly monitoring using Method 21 with a fugitive definition of 1,000 ppm while this proposal requires annual or stepped monitoring with a fugitive definition of 500 ppm if Method 21 is the chosen monitoring instrument. The

[103] See Docket ID Nos. EPA–HQ–OAR–2010–0505–7682, EPA–HQ–OAR–2010–0505–7685 and EPA–HQ–OAR–2010–0505–7686.

[104] See memorandum *Equivalency of State Fugitive Emissions Programs for Well Sites and Compressor Stations to Proposed Standards at 40 CFR part 60, subpart OOOOa* located at Docket ID No. EPA–HQ–OAR–2017–0483. April 12, 2018.

[105] Specifically, we propose to make this finding with respect to state programs in California, Colorado, Ohio, Pennsylvania, Texas, and Utah.

EPA believes that more frequent monitoring warrants allowance of a higher fugitive definition because larger fugitive emissions will be found faster and repaired sooner, thus reducing the overall length of the emission event. Additional information related to the specific evaluation of programs is available in the memorandum *Equivalency of State Fugitive Emissions Programs for Well Sites and Compressor Stations to Proposed Standards at 40 CFR part 60, subpart OOOOa,* located at Docket ID No. EPA–HQ–OAR–2017–0483.

Based on this evaluation, we are proposing combining those aspects of the state requirements to formulate alternatives to the relevant portions of the fugitive emissions standards for the collection of fugitive emissions components located at either well sites or compressor stations. The specific states for which we are proposing alternative standards are California, Colorado, Ohio, and Pennsylvania for both well sites and compressor stations, and Texas and Utah for well sites only. We have not determined whether Pennsylvania's Exemption No. 38 for well sites should be included in the alternative standards. While we evaluated the current consent decree [106] that the state of North Dakota has developed for well sites, we are not proposing alternative standards related to those requirements because by their nature, consent decrees are negotiated terms for non-compliance and contain an expiration date, after which sources return to compliance with the underlying regulatory provisions, permit terms, etc. Further, inclusion of settlement terms from a consent decree as an alternative standard would essentially endorse regulation through enforcement as a pathway to establishment of alternative standards. For all of these reasons, the EPA believes that evaluation of settlement agreement terms reached through negotiated resolution to an enforcement action would be an inappropriate basis from which to establish alternative standards for regulations promulgated through notice and comment rulemaking. Additionally, we are identifying the specific effective date of the individual state programs to specify which version of the state programs is being proposed as alternative standards because the state programs may change over time, and our evaluation is only valid for the current version of these programs. If in the future any of these programs are amended, the states can utilize the proposed application procedure discussed below.

The proposed alternative fugitive emissions standards include alternatives for monitoring frequencies, repair deadlines, and recordkeeping. The requirements for the monitoring plan found in 40 CFR 60.5397a(c) and (d) would still apply. In fact, the owner or operator would indicate through this monitoring plan that they have elected the alternative and would base the monitoring plan on the specific requirements from the state, local, or tribal program that is being adopted. Compliance would be evaluated against the specified requirements in the alternative fugitive emissions standards as incorporated in the monitoring plan. Further, we are proposing to require notification that the owner or operator has elected to comply with the applicable alternative fugitive emissions standards for the state in which the well site or compressor station is located. We are proposing that this notification is made at least 90 days prior to adopting an alternative fugitive emissions standard. We are soliciting comment on the requirements necessary to document that an owner or operator is following an alternative state, local or tribal program and on the notification requirement, including the appropriateness of the use of the requirement of 90 days' notice prior to adoption of the alternative standards.

In this action we are proposing a new section, in proposed 40 CFR 60.5399a, to include these state requirements that qualify as alternative fugitive emissions standards. The proposed section also includes a framework for the application and inclusion of additional existing state fugitive emissions standards as alternatives to the fugitive emissions requirements or future revisions to programs already proposed as alternative standards. Under our proposal, such applicants would include, but not be limited to, individuals, corporations, partnerships, associations, states, or municipalities. The proposed requirements for the application include specific information about the monitoring instrument (including monitoring procedures), monitoring frequency, leak or fugitive emissions definition, and repair requirements. We are soliciting comment on the proposed application requirements, the proposed alternative fugitive emissions standards (including compliance monitoring), and information to support the inclusion of additional alternative fugitive emissions standards.

E. Other Reconsideration Issues Being Addressed

1. Well Completions

Location of a Separator During Flowback. The 2016 NSPS OOOOa requires the owner or operator to have a separator onsite during the entirety of the flowback period. 40 CFR 60.5375a(a)(1)(iii). However, several petitioners indicated that it is not clear whether the term ''onsite'' refers to the specific well site where the well completion is taking place.[107] Our intent was that the separator be located in close enough proximity to the well that it could be utilized as soon as sufficient flowback is present for the separator to function. Close proximity could be either onsite or nearby, as we explained in the preamble to the 2016 NSPS OOOOa, ''We anticipate a subcategory 1 well to be producing or near other producing wells. We therefore anticipate REC equipment (including separators) to be onsite or nearby, or that any separator brought onsite or nearby can be put to use.'' 81 FR 35852. Thus, our intent was that the separator may be located at the well site or near to the well site so that it is able to commence separation flowback, as required by the rule. Locations ''near'' or ''nearby'' may include a centralized facility or well pad that services the well which is used to conduct the completion of the well affected facility. In order to alleviate concerns that the separator must be located on the well site, we are proposing to amend 40 CFR 60.5375a(a)(1)(iii) to clarify the location of the separator.

Screenouts and Coil Tubing Cleanouts. Petitioners requested clarification as to whether screenouts and coil tubing cleanouts are regulated as part of flowback. Petitioners asserted that these are necessary processes performed during hydraulic fracturing that are not associated with flowback.[108] In November 2016, the EPA responded to a letter from API seeking clarification on this issue, stating, ''any releases of gas or vapor during 'screenouts' and 'coil tubing cleanouts,' which occur during the initial flowback stage are not subject to control under section 60.5375a.[109] However, we have further assessed this topic and believe that the guidance we issued was incorrect. In the

[106] See North Dakota Consent Decree 10.19.16, attachment to the memorandum *Equivalency of State Fugitive Emissions Programs for Well Sites and Compressor Stations to Proposed Standards at 40 CFR part 60, subpart OOOOa.* April 12, 2018, in Docket ID No. EPA–HQ–OAR–2017–0483.

[107] See Docket ID Nos. EPA–HQ–OAR–2010–0505–7682 and EPA–HQ–OAR–2010–0505–7686.

[108] See Docket ID No. EPA–HQ–OAR–2010–0505–7682.

[109] See Docket ID No. EPA–HQ–OAR–2010–0505–7722.

preamble to the final 2014 amendments, we stated regarding flowback: ''. . . the first stage would begin with the first flowback from the well following hydraulic fracturing or refracturing, and would be characterized by high volumetric flow . . .'' 79 FR 79024. In some situations, screenouts or coil tubing cleanouts may be necessary in order to remove proppant (sand) from the well so that high volumetric flow can occur, marking the beginning of the initial flowback stage. Therefore, screenouts and coil tubing cleanouts are not a part of flowback; rather, they are functional processes that allow for flowback to begin. It should be noted that this is consistent with the definition of hydraulic fracturing, which we stated requires high rate, extended flowback to expel fracture fluids and solids during completions. 40 CFR 60.5430a. For the reasons stated above, the November 2016 letter incorrectly states that screenouts and coil tubing cleanouts occur during the initial flowback stage. To clarify this point, we are proposing to revise the definition of flowback to expressly exclude these processes to avoid any future confusion. In addition, we are proposing definitions for these processes. A screenout is the first attempt to clear proppant from the wellbore. It involves flowing the well to a fracture tank in order to achieve maximum velocity and carry the proppant out of the well. If a screenout is unsuccessful in clearing the proppant from the wellbore, then a coil tubing cleanout is conducted. This involves running a string of coil tubing to the packed proppant and jetting the well to dislodge the proppant and provide sufficient lift energy to flow it to the surface. It is after these processes that flowback begins and, subsequently, production. The EPA solicits comment on the proposed definitions for these processes.

Plug Drill-Outs. A plug drill-out is the removal of a plug (or plugs) that was used to conduct hydraulic fracturing in different sections of the well. Plug drill-outs are also functional processes that are necessary in order for flowback to begin. Therefore, the EPA is similarly proposing to exclude these processes from the definition of flowback.

Flowback Routed Through Permanent Separators. The EPA is proposing to streamline reporting and recordkeeping requirements for flowback routed through permanent separators to reduce burden on the regulated community. We consider a permanent separator to be one that handles flowback from a well or wells beginning when the flowback period begins and continuing to the startup of production. When routing flowback through permanent separators, some reporting and recordkeeping elements associated with well completions (*e.g.,* information about when a separator is hooked up or disconnected) become unnecessary because the separator is already connected to the well at the onset of flowback. In these situations, there is no initial flowback stage, and the separation flowback stage begins. Therefore, the EPA is proposing that operators do not need to record or report the date and time of each attempt to direct flowback to a separator for these situations. However, these streamlined recordkeeping and reporting requirements would not apply in situations where flowback is not routed through a permanent separator; in those cases, operators would be required to report the date and time of each attempt to direct flowback to a separator. The EPA is soliciting comments on these proposed revisions and additional ways to streamline reporting and recordkeeping.

2. Onshore Natural Gas Processing Plants

Capital Expenditure. We are proposing to correct the definition of ''capital expenditure'' promulgated at 40 CFR 60.5430a by replacing the reference to the year 2011 with the year 2015 in the formula in paragraph (2) of the definition. The definition of ''capital expenditure'' was among the issues related to 40 CFR part 60, subpart OOOO that the EPA reconsidered and addressed in the 2016 NSPS OOOOa. That definition is relevant to the equipment leaks standards for onshore natural gas processing plants that were originally promulgated in 1985 in 40 CFR part 60, subpart KKK, updated in 2012 in 40 CFR part 60, subpart OOOO, and carried over in 2016 in 40 CFR part 60, subpart OOOOa. As explained in the memorandum *Alternative Method for Determining Capital Expenditures (Thomas W. Rhoads to Docket A–80–44, July 21, 1983),* located at Docket ID No. EPA–HQ–OAR–2017–0483, this method was developed to allow a facility to approximate the original costs of the facility using the replacement costs and the inflation index and therefore, providing an alternative method to the definition of ''capital expenditure'' in 40 CFR part 60, subpart A (''General Provisions'').[110] The value for ''Y'' (the percent of replacement cost) is designed to take into account the age of the facility. Therefore, the replacement cost for a new facility should be the same as the original cost, or the value of ''Y'' should be closer to 1 for new facilities. Because the 2016 NSPS OOOOa applies to new sources constructed, reconstructed, or modified after September 18, 2015, the base year of 2015 is the correct year to reflect the age of the facility in this calculation.

However, for sources that commenced construction between January 1, 2015, and September 18, 2015, when the value of ''2015'' is used it results in a ''zero'' value for ''X'' for which there is no logarithmic solution. This is a result that the EPA did not intend in its revision of the calculation in the 2016 rulemaking. The EPA is, therefore, amending the definition so that the value of ''Y'' equals 1 if the affected process unit was constructed in 2015. The proposed amendment would address the mathematical issue for affected sources constructed in 2015 whiling leaving the calculation method intact for other affected sources. We are soliciting comment on the proposed amendment to the equation.

Notwithstanding this proposed amendment, as indicated above, the equation was developed as an alternative to the General Provisions definition of ''capital expenditure.'' Since the General Provisions definition also applies, if calculation issues arise when applying the 2016 NSPS OOOOa equation, facilities should use the General Provisions to calculate capital expenditure. Facilities can also contact the EPA for guidance on how to apply the General Provisions definition for ''capital expenditure'' evaluations if necessary by utilizing 40 CFR 60.5 (Determination of construction or modification).

In addition, the EPA is soliciting comment and information to help inform us whether the current capital expenditure definition should be revised based on a ratio of consumer price indices (CPI), as requested by two petitioners.[111] Petitioners indicated that calculation of ''capital expenditure'' was designed to account for inflation. In supporting documentation provided from one petitioner[112] a plot of values prior to 1982 demonstrates a logarithmic function, which directly correlates to the CPI for the years 1950 through 1982. This was the information on which the ''capital expenditure'' equation was based. However, as described by the

[110] See also *Equipment Leaks of VOC in Natural Gas Production Industry—Background for Promulgated Standards,* EPA–450/3–82–024b, May 1985, at 9–1.

[111] See Docket ID Nos. EPA–HQ–OAR–2010–0505–7682 and EPA–HQ–OAR–2010–0505–7684.

[112] See *GPA Midstream New Source Performance Standards (''NSPS'') Subpart OOOOa Petition for Review Technical Issues* located at Docket ID No. EPA–HQ–OAR–2010–0505–12361. March 1, 2017.

petitioners, the CPI takes a more linear function post-1982, while the ''capital expenditure'' equation remains with a logarithmic function. In practice, this could mean that the ''P'' value would be lower using the ''capital expenditure'' equation, thus resulting in modifications at lower expenditures than if the CPI were used. While we are proposing to update the existing equation with the corrected base year date of 2015, we are also soliciting comment on changing the calculation for the value of ''Y'' using the CPI. Specifically, we are soliciting comment on the petitioner's suggestion that the value for ''Y'' should be calculated using the CPI of the date of construction or reconstruction divided by the CPI of the date of component price data, or ''CPI_N/CPI_{PD}''.

3. Closed Vent Systems (CVS) and Storage Vessel Thief Hatches

The requirements for CVS are specific to the type of affected facility that is associated with the CVS (*i.e.,* ''routes to'' the CVS). CVS receiving emissions from centrifugal compressor, reciprocating compressor, and pneumatic pump affected facilities must be (a) initially and annually inspected visually for defects and (b) initially and annually monitored using Method 21 to verify operation at no detectable emissions (*i.e.,* an instrument reading less than 500 ppm above background concentration). In contrast, no instrument monitoring is required for CVS receiving emissions from storage vessel affected facilities and monthly auditory, visual, and olfactory (AVO) inspections must be performed. 40 CFR 60.5416a. Several petitioners have stated that the requirements for CVS associated with pneumatic pumps should be aligned with the requirements for CVS associated with storage vessels instead of the CVS requirements for centrifugal or reciprocating compressors.[113] In addition, these petitioners stated, though incorrectly, that pneumatic pumps are subject to OGI monitoring under the fugitive emissions requirements as well as the annual Method 21 requirement; the petitioners, therefore, assert that the Method 21 requirement is duplicative and burdensome. Pneumatic pumps are not fugitive emissions components because they vent as part of normal operation. Finally, stakeholders have requested streamlined and standardized requirements for all CVS, in place of equipment-specific requirements currently in the 2016 NSPS OOOOa. Specifically, the requirements are spread over multiple sections of the rule and vary based on the affected facility associated with the CVS as stated above, which the stakeholders have indicated creates confusion regarding compliance.

The EPA has received information from various stakeholders that overlapping requirements for these CVS and openings on controlled storage vessels may still exist due to state program requirements. Specifically, two stakeholders have informed us they are required to perform quarterly OGI monitoring on the CVS located at well sites under their state program in addition to the annual Method 21 requirement on the same CVS for their affected facility pneumatic pumps as required by the 2016 NSPS OOOOa. We agree with the stakeholders that amendments are appropriate for the CVS requirements for pneumatic pumps.

We are proposing to align the CVS monitoring requirements for affected facility pneumatic pumps with the CVS monitoring requirements for affected facility storage vessels. As stated by the petitioners, we agree that pneumatic pumps and storage vessels are commonly located at well sites and agree that having separate monitoring requirements for potentially shared CVS is overly burdensome and duplicative. This proposed amendment effectively requires monthly AVO monitoring for the CVS located at well sites because there are no affected facility reciprocating or centrifugal compressors located at well sites. We are soliciting comment on this proposed amendment for CVS on affected facility pneumatic pumps. Additionally, we are soliciting comment on other methods that could be employed as an alternative to the monthly AVO monitoring to ensure the CVS is operated with no detectable emissions.

Further, we are soliciting comment regarding the requirements for covers, thief hatches and other openings on storage vessel affected facilities. As specified in 40 CFR 60.5411a(b)(2), each opening on the storage vessel cover should be secured in a closed and sealed position except during periods where opening the cover is necessary (*e.g.,* to inspect or sample material in the storage vessel). Under 40 CFR 60.5416a(c)(2), each cover is also subject to monthly AVO monitoring for defects that could result in air emissions. It has come to our attention, however, that there may be confusion related to how the cover and openings on the cover relate to the CVS and the no detectable emissions requirement. We have observed fugitive emissions using OGI on thief hatches, even where the CVS has been properly designed and certified, and the thief hatch is properly weighted and closed.[114] Given this information, we acknowledge there are concerns about an interpretation of 40 CFR 60.5411a(c)(2) under which thief hatches are subject to the no detectable emissions limit. We recognize that this limit is traditionally required for components that we do not expect to leak (*e.g.,* valves with no external actuating shaft in contact with process fluid). However, as noted here, we continue to observe fugitive emissions from thief hatches that are properly weighted and closed. Root cause analysis has demonstrated that deteriorated gaskets are one cause of such emissions. While these sources might still be able to meet the sensory monitoring limit, we are soliciting comment on whether covers and openings on the cover should be viewed as part of the CVS and thus subject to the no detectable emissions limit. In addition, we are soliciting comment on whether other methods are available to more reliably identify fugitive emissions from the CVS and thief hatches or other openings on storage vessel affected facilities than the currently required monthly AVO and to better assure compliance with the 95% VOC emissions control requirement for storage vessel affected facilities. We are also soliciting comment on whether a work practice standard would be more effective at assuring compliance than subjecting thief hatches to a no detectable emissions standard as determined through monthly AVO. Finally, we are not proposing any changes to the CVS requirements for affected facility centrifugal compressors or reciprocating compressors.

VII. Implementation Improvements

Following publication of the 2016 NSPS OOOOa, we subsequently determined, following review of petitions and discussions with affected parties, that the final rule warrants correction and clarification in certain areas in addition to those discussed above. Each of these areas is discussed below.

[113] See Docket ID Nos. EPA–HQ–OAR–2010–0505–7682, EPA–HQ–OAR–2010–0505–7685 and EPA–HQ–OAR–2010–0505–7686.

[114] *Analysis of Consent Decree Reports from Noble Energy, Inc. as to Emissions Observations from Thief Hatches or Other Openings on Controlled Storage Vessels; Oil and Natural Gas Sector: Emission Standards for New, Reconstructed and Modified Sources Reconsideration—SAN 5719.8* located at Docket ID No. EPA–HQ–OAR–2017–0483.

A. Reciprocating Compressors

The 2016 NSPS OOOOa includes an alternative to the work practice standards for reciprocating compressors. Operators may choose to gather rod packing emissions using a collection system that operates under negative pressure and then route emissions to a process via a CVS, as opposed to replacing the rod packing every 26,000 hours or 36 months. During the comment period for the proposal for the 2016 NSPS OOOOa, the EPA received feedback from various stakeholders, who noted that there were safety concerns with requiring the rod packing emissions to be collected under negative pressure. Specifically, commenters stated that operating the collection system under negative pressure may inadvertently introduce oxygen into the system.[115] In response to comments, the EPA stated that operation of the collection system under negative pressure was necessary in order to appropriately capture emissions.[116] The EPA is soliciting comment and supporting data on capture systems which are at least equivalent to the current systems and which could negate the necessity to capture emissions under negative pressure.

B. Storage Vessels

Pursuant to 40 CFR 60.5365a(e), owners and operators must calculate potential emissions from storage vessels in order to determine if control requirements apply. This calculation is based on the ''maximum average daily throughput.'' During implementation of the 2016 NSPS OOOOa, several stakeholders requested clarification regarding this calculation. Specifically, the stakeholders have expressed confusion about what value constitutes the ''maximum average daily throughput.'' This value was intended to represent the maximum of the average daily production rates in the first 30-day period to each individual storage vessel. The EPA stated in its Response to Comments on the 2013 amendments to the 2012 NSPS OOOO, ''we believe that the estimate of potential VOC emissions should be determined based on maximum emissions during the 30-day period rather than average emissions over that period''.[117] While the EPA was clear that emissions are not to be averaged over the 30-day period, we were less clear at the time as to what averaging was allowed when we used the term ''maximum average daily throughput.'' Therefore, we propose to further clarify in this notice when and how daily production may be averaged in determining daily throughput.

We are proposing to revise the definition to clarify that the maximum average daily throughput refers to the maximum average daily throughput for an individual storage vessel over the days that production is routed to that storage vessel during the 30-day evaluation period. This average over the days that production is routed to a storage vessel represents the maximum average daily throughput for that single storage vessel because the determination takes place during the first 30-day evaluation period when production throughput will be the greatest due to the decline curve for production from oil and natural gas wells. Further, by clarifying that production to a single storage vessel must be averaged over the number of days production was actually sent to that storage vessel, rather than over the entire 30 days (where the storage vessel receives no production on some days), we are ensuring that the determination of potential for VOC emissions to that individual storage vessel does not presume that production will be split evenly across storage vessels where there is no legally and practically enforceable limit requiring operation in that manner. A more detailed discussion regarding the issue of averaging across a tank battery is provided below. We are soliciting comment on this clarification. Additionally, we are soliciting comment on whether a different term would better describe this value than the currently used ''maximum average daily throughput.''

Where a storage vessel has automated gauging, the operator may directly determine the average daily throughput for each day that production is routed to that storage vessel. The average daily throughput for each day of production to that storage vessel would then be averaged to determine the maximum average daily throughput for the 30-day evaluation period. For example, if a storage vessel receives production on 22 of the 30 days in the evaluation period, then the maximum average daily throughput is calculated by averaging the daily throughput that was calculated for each of those 22 days. We recognize that this approach averages the daily throughputs for the days that a storage vessel receives production; however, recognizing that production declines, we are clarifying that this calculation, based on the days of production to the storage vessel during the first 30-days of production, represents the potential emissions. We are soliciting comment on this clarification.

We understand that some storage vessels may not have daily throughput measurements because they are not equipped with automated level gauging and do not have daily manually gauged readings. In such circumstances, we believe that the liquid height, and therefore volume, in the storage vessel would be measured at a minimum at the start and completion of loadout of liquids from the storage vessel. Frequency of loadout from each storage vessel (*i.e.,* ''turnover rate'') will vary depending on company or site-specific operations. Therefore, it is possible that a storage vessel could have multiple turnovers during the first 30-days of production, and therefore multiple production periods. Where this occurs, you must determine the average daily throughput for each of those production periods, which can be done by dividing the volumetric throughput calculated from the change in liquid height for that production period over the number of days in the production period, and use the maximum of those production period average daily throughput values to calculate the potential emissions from the individual storage vessel. 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. We recognize that calculating daily throughput based on liquid level measurements at the beginning and end of a production period will necessarily average production throughput to the individual storage vessel over the number of days it was receiving production in the turnover period. However, recognizing that production declines, we are clarifying that this calculation, based on the first 30-days of production, represents the potential emissions. We are soliciting comment on this clarification.

Finally, inspection data and compliance reports for the 2016 NSPS OOOOa indicate that many operators determined that few or no storage vessels are affected facilities under the 2016 NSPS OOOOa. For example, review of the 2016 NSPS OOOOa compliance reports and the fewer than expected number of reported storage vessel affected facilities indicates that some operators may be incorrectly averaging emissions across storage tanks in tank batteries when determining the potential for VOC emissions. Both the

[115] See Docket ID No. EPA–HQ–OAR–2010–0505–6884.

[116] See Docket ID No. EPA–HQ–OAR–2010–0505–7632, Chapter 7, page 7–37.

[117] See Docket ID No. EPA–HQ–OAR–2010–0505–4639.

2012 NSPS OOOO and 2016 NSPS OOOOa specify that a storage vessel affected facility is ''a single storage vessel'' that ''has the potential for VOC emissions equal to or greater than 6 tpy.'' 40 CFR 60.5365(e) and 60.5365a(e). In prior rulemakings, the EPA explained that storage vessel emission estimation methods for the potential for VOC emissions generally require information on both the composition and volumetric rate of the liquid entering the storage vessel, where the volumetric throughput is frequently calculated by recording the volume of liquid collected from the receiving vessel(s) over time. 79 FR 79026. Because the 2012 NSPS OOOO and 2016 NSPS OOOOa define the affected facility as ''a single storage vessel,'' the determination of the potential for VOC emissions must be based on the liquid throughput of each ''single storage vessel,'' even where the storage vessel is part of a tank battery. Operators should ensure that the determination of the potential for VOC emissions reflects each storage vessel's actual configuration and operational characteristics. Similarly, the EPA notes that affected facility determinations are allowed to account for legally and practically enforceable limits in determining the potential for VOC emissions for a storage vessel. However, 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. Given the potential for recurring emissions from controlled storage vessel thief hatches or other opening owing to operation and maintenance performance even where adequate design has been verified,[118] any limit on capture and control efficiency from storage vessels must include sufficient monitoring to timely identify and repair emissions from storage vessels to ensure the limit on capture and control efficiency is consistently achieved.

Where a storage vessel is part of a tank battery, some operators appear to derive the maximum average daily throughput of a storage vessel in a battery by using the throughput to the entire battery (by using records of liquids collected from the battery over time) and dividing that figure by the number of storage vessels in the battery. This approach for determining a storage vessel's maximum average daily throughput is incorrect for certain operational configurations. For instance, where a tank battery is operated such that all pressurized liquids from the separator initially flow to only one storage vessel, and then overflow to the next, and so on (*i.e.,* in series or series flow), the first individual storage vessel's throughput would be the entire battery's throughput, not the entire battery's throughput apportioned evenly among the storage vessels. Dividing an entire battery's throughput by the number of storage vessels in the battery would greatly underestimate flash emissions from the first storage vessel connected in series, which is where liquid pressure drops from separator pressure to atmospheric pressure. However, such division could be appropriate where all liquids flow through a splitter system in a common header that ensures that all liquids initially flow in equal amounts to all storage vessels in a tank battery at all times since the liquid pressure drop would occur equally in each storage vessel in the battery. The EPA is soliciting comment and suggestions for how to clarify or simplify the calculation for application by stakeholders such that the potential emissions from storage vessels may be determined.

Finally, records of each VOC emissions determination for each storage vessel affected facility are required in 40 CFR 60.5420a(c)(5)(ii). Given the proposed clarification discussed above, we are soliciting comment on specific recordkeeping requirements that would support the applicability determination for each individual storage vessel regardless of whether that storage vessel is determined to be an affected facility. This is because recordkeeping is necessary to be able to verify that rule applicability was appropriately determined in accordance with the regulatory requirements. We are soliciting comment on the type of records that would be maintained to demonstrate how the calculations of the maximum average daily throughput and the potential for VOC emissions were performed. For example, information related to how the throughput to the individual storage vessel was determined (*i.e.,* daily measurements or liquid height measurements at the start and end of a production period) and the start and end dates for each production period, along with the number of days production was routed to that storage vessel, are key elements that we would expect to have recorded. Where automated readings from gauges or meters are available, we expect that a data historian could automatically record and store some or all of this information. Where automated readings are not available, load slips may be able to provide some or all of this information (*i.e.,* liquid height in a storage vessel at the beginning and end of each load out and the date of the load out, traceable to the storage vessel). We are also soliciting comment on records that would be available to document the operational configuration of a tank battery, where applicable, including to which storage vessel(s) production was routed for each day in the 30-day evaluation period. For calculation of potential for VOC emissions, we expect that identification of the model or calculation methodology used would be documented with the calculation itself. In addition to the type of information that should be recorded, we are also soliciting comment on the associated recordkeeping burden.

C. Definition of Certifying Official

In response to petitions on NSPS OOOO, the EPA amended the definition of 'responsible official' in order to remove potential confusion in the regulated community and to clarify that the requirements of the NSPS were not associated with a permitting program.[119] Because the terms 'responsible official' and 'permitting authority' were similar to terms used in the Title V permitting program, the EPA changed the term 'responsible official' to 'certifying official' and replaced the term 'permitting authority' used in the definition with 'Administrator.' ''[120] This amended definition of 'certifying official' was carried forward into the 2015 NSPS OOOOa proposal. 80 FR 56694. The EPA received comments that the term 'certifying official' still includes references to permitting programs and is inconsistent with way the NSPS program operates.[121] In response to this comment, the EPA stated that the change made in the 2014 amendments ''remove[d] any confusion.'' [122] Upon further evaluation of this issue, the EPA recognizes that continuing to include the language ''facilities applying for or subject to a permit'' in the definition of 'certifying

[118] *Analysis of Consent Decree Reports from Noble Energy, Inc. as to Emissions Observations from Thief Hatches or Other Openings on Controlled Storage Vessels; Oil and Natural Gas Sector: Emission Standards for New, Reconstructed and Modified Sources Reconsideration—SAN 5719.8* located at Docket ID No. EPA–HQ–OAR–2017–0483.

[119] 79 FR 79023–4.

[120] *Id.*

[121] See Docket ID No. EPA–HQ–OAR–2010–0505–6881.

[122] See Docket ID No. EPA–HQ–OAR–2010–0505–7632, Chapter 15, page 15–284.

official' is inappropriate for the NSPS program. Therefore, the EPA is proposing to amend this definition to remove the reference to permits. The EPA solicits comment on this proposed change.

D. Equipment in VOC Service Less Than 300 Hours/Year

In this action, the EPA is proposing to amend the requirements for equipment leaks at onshore natural gas processing plants. Specifically, we are proposing to include an exemption from monitoring for certain equipment that an owner or operator designates as being in VOC service less than 300 hr/yr.

When the 2007 requirements were promulgated, the EPA concluded that an exemption for certain equipment that is in VOC service less than 300 hr/yr was appropriate. In response to public comments on the 2006 NSPS VV/VVa proposal, we stated that such exemption was appropriate for equipment that is used only during emergencies, used as a backup, or that is in service only during startup and shutdown.[123] In these situations, the operating schedule of the equipment is unpredictable and likely at widely spaced and varying intervals. Planning for monitoring is more challenging and the effort outweighs the limited potential gain in emissions. The EPA is proposing to include this same exemption for 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.

E. Reporting and Recordkeeping

The EPA is proposing to streamline certain reporting and recordkeeping requirements to reduce burden on the regulated industry. The proposed changes can be seen in section 60.5420a. Additionally, the proposed reporting elements can be seen in the draft electronic reporting template, located at Docket ID No. EPA–HQ–OAR–2017–0483. We solicit comment on these proposed revisions; the content, layout, and overall design of the reporting template; and additional ways to streamline reporting and recordkeeping.

We are also proposing revisions to accommodate the submittal of CBI data in annual reports, as well as additional clarifications for reporting requirements during outages of the Compliance and Emissions Data Reporting Interface (CEDRI) or the EPA's Central Data Exchange (CDX) systems, or during a force majeure event. These proposed changes can be seen in section 60.5420a.

F. Technical Corrections and Clarifications

We are proposing to revise the 2016 NSPS OOOOa to include the following technical corrections and clarifications.

- Revise paragraphs 60.5385a(a)(1), 60.5410a(c)(1), 60.5415a(c)(1), 60.5420a(b)(4)(i), and 60.5420a(c)(3)(i) to clarify that hours or months of operation at reciprocating compressor facilities should be measured beginning with the later of initial startup, the effective date of the requirement (August 2, 2016), or the last rod packing replacement.
- Revise paragraph 60.5393a(b)(3)(ii) to correctly cross-reference to paragraph (b)(3)(i) of that section.
- Revise paragraph 60.5397a(c)(8) to clarify the calibration requirements when Method 21 of Appendix A–7 to Part 60 is used for fugitive emission monitoring.
- Revise paragraph 60.5397a(d)(3) to correctly cross-reference paragraphs (g)(3) and (g)(4) of that section.
- Revise paragraph 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 Alaskan North Slope are not subject to any monitoring requirements.
- Revise paragraph 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. This proposed revision reflects that the 2016 NSPS OOOOa did not finalize requirements for pneumatic pumps in the gathering and boosting and transmission and storage segments. 81 FR 35850.
- Revise paragraph 60.5411a(a)(1) to remove the reference to paragraphs 60.5412a(a) and (c) for reciprocating compressor affected facilities.
- Revise paragraph 60.5411a(d)(1) to remove the reference to storage vessels, as this paragraph applies to all the sources lists in paragraph 60.5411a(d), not only storage vessels.
- Revise paragraphs 60.5412a(a)(1), 60.5412a(a)(1)(iv), 60.5412a(d)(1)(iv), and 60.5412a(d)(1)(iv)(D) to clarify that all boilers and process heaters must introduce the vent stream into the flame zone and that the performance requirement option for combustion control devices on centrifugal compressors and storage vessels is to introduce the vent stream with the primary fuel or as the primary fuel. This is consistent with the performance testing exemption in section 60.5413a and continuous monitoring exemption in section 60.5417a for boilers and process heaters that introduce the vent stream with the primary fuel or as the primary fuel.
- Revise paragraph 60.5412a(c) to correctly reference both paragraphs (c)(1) and (c)(2) of that section, for managing carbon in a carbon adsorption system.
- Revise paragraph 60.5413a(d)(5)(i) to reference fused silica-coated stainless steel evacuated canisters instead a specific name brand product.
- Revise paragraph 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 paragraph 60.5413a(d)(12) to clarify that all data elements must be submitted for each test run.
- Revise paragraph 60.5415a(b)(3) to reference all the applicable reporting and recordkeeping requirements.
- Revise paragraph 60.5416a(a)(4) to correctly cross-reference paragraph 60.5411a(a)(3)(ii).
- Revise paragraph 60.5417a(a) to clarify requirements for controls not specifically listed in paragraph (d) of that section.
- Revise paragraph 60.5422a(b) to correctly cross-reference paragraphs 60.487a(b)(1) through (3) and (b)(5).
- Revise paragraph 60.5422a(c) to correctly cross-reference paragraph 60.487a(c)(2)(i) through (iv) and (c)(2)(vii) through (viii).
- Revise paragraph 60.5423a(b) to simplify the reporting language and clarify what data is required in the report of excess emissions for sweetening unit affected facilities.
- Revise paragraph 60.5430a to remove the phrase ''including but not limited to'' from the ''fugitive emissions component'' definition. This proposed revision reflects that in the response to comments document for the 2016 NSPS OOOOa we stated we were removing this phrase.[124]
- Revise paragraph 60.5430a to remove the phrase ''at the sales meter'' from the ''low pressure well'' definition. 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 section 60.8 do not apply to pneumatic pump affected facilities.

[123] See Docket ID No. EPA–HQ–OAR–2006–0699–0094.

[124] See Docket ID No. EPA–HQ–OAR–2010–0505–7632, Chapter 4, page 4–319.

- 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 paragraphs 60.5393a(f), 60.5410a(e)(8), 60.5411a(e), 60.5415a(b), 60.5415a(b)(4), 60.5416a(d), 60.5420a(b), 60.5420a(b)(13), and introductory text in 60.5411a and 60.5416a to remove the language added in the ''Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources; Grant of Reconsideration and Partial Stay'' (June 5, 2017), which was vacated by the U.S. Court of Appeals for the D.C. Circuit on July 3, 2017.

VIII. Impacts of This Proposed Rule

A. What are the air impacts?

For this action, the EPA estimated the change in emissions that will occur due to the implementation of the proposed NSPS reconsideration for the analysis years of 2019 through 2025. We estimate impacts beginning in 2019 to reflect the year implementation of this reconsideration will begin, assuming it is finalized within the next year. We estimate impacts through 2025 to illustrate the continued compound effect of this rule over a longer period. We do not estimate impacts after 2025 for reasons including limited information, as explained in the RIA (Regulatory Impact Analysis). The regulatory impact estimates for 2025 include sources newly affected in 2025 as well as the accumulation of affected sources from 2016 to 2024 that are also assumed to be in continued operation in 2025, thus incurring compliance costs and emissions reductions in 2025.

We have estimated that, over the 2019 through 2025 timeframe, assuming semiannual monitoring at compressor stations, the proposed NSPS reconsideration would increase methane emissions by about 380,000 short tons, and VOC emissions by about 100,000 tons from facilities affected by this reconsideration compared to emissions under the 2018 updated baseline, as described in the RIA. The proposed reconsideration is also expected to concurrently increase hazardous air pollutant (HAP) emissions by about 3,800 tons from 2019 through 2025. Section 2 of the RIA contains an analysis of the increase in emissions as a result of this proposed reconsideration under the co-proposed option of annual monitoring at compressor stations. As seen in section 2.5.2 of the RIA, the co-proposed option of annual fugitive emissions monitoring results in greater total emissions than those under the co-proposed option of semiannual fugitive emissions monitoring at compressor stations outside of the Alaskan North Slope. Over 2019 through 2025, fugitive emissions under the co-proposed option assuming annual monitoring are about 100,000 short tons greater for methane, 24,000 tons greater for VOC, and 890 tons greater for HAP than those under the co-proposed option assuming semiannual fugitive emissions monitoring.

As described in the TSD and RIA for this rule, the EPA projected affected facilities using a combination of historical data from the United States GHG Inventory, projected activity levels taken from the Energy Information Administration (EIA's) Annual Energy Outlook (AEO), and oil and natural gas production information from DrillingInfo, a private company that provides information and analysis to the energy sector. The EPA also considered state regulations with similar requirements to the proposed NSPS in projecting affected sources for impacts analyses supporting this rule.

B. What are the energy impacts?

Energy impacts in this section are those energy requirements associated with the operation of emission control devices. Potential impacts on the national energy economy from the rule are discussed in the economic impacts section. There would be little change in the national energy demand from the operation of any of the environmental controls proposed in this action. The proposed NSPS reconsideration 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.

C. What are the compliance cost savings?

Assuming the co-proposed option of semiannual monitoring at compressor stations, the EPA estimates the PV of compliance cost savings of the proposed reconsideration over 2019–2025, discounted back to 2016, will be $429 million (in 2016 dollars) under a 7 percent discount rate, and $546 million under a 3 percent discount rate, not including the forgone producer revenues associated with the decrease in the recovery of saleable natural gas. The EAV of these cost savings are $74 million per year using a 7 percent discount rate and $85 million per year using a 3 percent discount rate. In this analysis, we use the 2018 AEO projection of natural gas prices to estimate the value of the change in the recovered gas at the wellhead. After accounting for the change in these revenues, the estimate of the PV of compliance cost savings of the proposed reconsideration over 2019–2025, discounted back to 2016, are estimated to be $380 million under a 7 percent discount rate, and $484 million under a 3 percent discount rate; the corresponding estimates of the EAV of cost savings after accounting for the forgone revenues are $66 million per year under a 7 percent discount rate, and $75 million per year under a 3 percent discount rate.

Compared to the estimated cost savings of the co-proposed option under semiannual fugitive emissions monitoring at compressor stations, the co-proposed option assuming annual monitoring results in greater cost savings. Assuming a 7 percent discount rate, and including the forgone value of product recovery, the PV of the total cost savings from 2019 through 2025 are about $43 million greater under annual monitoring than under semiannual monitoring. This is associated with an increase in the EAV of total cost savings of about $7.5 million per year in comparison to the co-proposed option under semiannual monitoring. A summary of the cost savings and forgone emission reductions associated with the co-proposed option of annual fugitive emissions monitoring at compressor stations is located in section 2.5.2 of the RIA.

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 OOOOa on the United States energy system. The NEMS is a publicly-available model of the United States energy economy developed and maintained by the EIA and is used to produce the AEO, a reference publication that provides detailed forecasts of the United States energy economy.

The EPA estimated small impacts of that rule over the 2020 to 2025 period relative to the baseline for that rule. The proposed reconsideration is estimated to result in a decrease in total costs compared to the updated 2018 baseline, and the 2016 NSPS OOOOa, with the change in costs affecting a subset of the total costs estimated for the 2016 NSPS OOOOa. Therefore, the EPA expects that this deregulatory action, if finalized, would partially ameliorate the impacts estimated for the final NSPS in the 2016 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 particular concern in the current economic climate given continued interest in the employment impact of regulations such as this proposed rule.

The EPA estimated the labor impacts due to the installation, operation, and maintenance of control equipment, control activities, and labor associated with new reporting and recordkeeping requirements in the 2016 NSPS OOOOa RIA. For the proposed reconsideration, the EPA expects there will be slight reductions in the labor required for compliance-related activities associated with the 2016 NSPS OOOOa requirements relating to fugitive emissions and inspections of closed vent systems. However, due to uncertainties associated with how the proposed reconsideration will influence the portfolio of activities associated with fugitive emissions-related requirements, the EPA is unable to provide quantitative estimates of compliance-related labor changes.

E. What are the forgone benefits of the proposed standards?

The EPA estimated the forgone domestic climate benefits from the methane emissions associated with this reconsideration using an interim measure of the domestic social cost of methane ($SC–CH_4$). The $SC–CH_4$ estimates used here were developed under E.O. 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. E.O. 13783 directed agencies to ensure that estimates of the social cost of greenhouse gases 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'' (E.O. 13783, Section 5(c)). In addition, E.O. 13783 withdrew the technical support documents (TSDs) and the August 2016 Addendum to these TSDs describing the global social cost of greenhouse gas 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 (IWG) that included the EPA and other executive branch entities and were used in the 2016 NSPS RIA.

The forgone benefits of the proposed reconsideration are estimated based on semiannual monitoring at compressor stations and are in comparison to an updated baseline with the 2016 NSPS OOOOa and the March 12, 2018 amendments with respect to the Alaskan North Slope in place.[125] The EPA estimates the PV of the forgone domestic climate benefits over 2019–2025, discounted back to 2016, will be $13.5 million under a 7 percent discount rate and $54 million under a 3 percent discount rate. The EAV of these forgone benefits is $2.3 million per year under a 7 percent discount rate and $8.3 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.

The EPA expects that the forgone VOC emission reductions may degrade air quality and adversely affect health and welfare effects associated with exposure to ozone, $PM_{2.5}$, and HAP, however data limitations prevent us from quantifying forgone VOC-related health benefits. This omission should not imply that these forgone benefits may not exist; rather, it reflects the difficulties in modeling the direct and indirect impacts of the reductions in emissions for this industrial sector with the data currently available. As described in the RIA, with these data currently unavailable, we are unable to estimate forgone health benefits estimates for this rule due to the differences in the locations of oil and natural gas emission points relative to existing information and the highly localized nature of air quality responses associated with HAP and VOC reductions.

[125] While the EPA is co-proposing annual monitoring for compressor stations, this discussion of forgone benefits is limited to the proposal of semiannual monitoring for compressor stations. For additional information regarding the cost savings and forgone emission reductions, see section 2 of the RIA.

IX. Statutory and Executive Order Reviews

Additional information about these statutes and Executive Orders can be found at *http://www2.epa.gov/laws-regulations/laws-and-executive-orders.*

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

This action is an economically significant regulatory action that was submitted to the OMB for review. Any changes made in response to OMB recommendations have been documented in the docket. The EPA prepared an analysis of the potential costs and benefits associated with this action. This Regulatory Impact Analysis (RIA) is available in the docket. The RIA describes in detail the empirical basis for the EPA's assumptions and characterizes the various sources of uncertainties affecting the estimates below. Table 4 shows the present value and equivalent annualized value results of the cost and benefits analysis for the proposed rule, assuming semiannual monitoring at compressor stations, for 2019 through 2025, discounted back to 2016 using a discount rate of 7 percent. The table also shows the total increase in emissions from 2019 through 2025 from this proposed reconsideration. When discussing net benefits, we modify the relevant terminology to be more consistent with traditional net benefits analysis. In the following table, we refer to the cost savings as presented in section 2 of the RIA, and in section VIII.C, above, as the ''benefits'' of this proposed action and the forgone benefits as presented in section 3 of the RIA, and in section VIII.E, above, as the ''costs'' of this proposed action. The net benefits are the benefits (cost savings) minus the costs (forgone benefits).

TABLE 4—SUMMARY OF THE PRESENT VALUE AND EQUIVALENT ANNUALIZED VALUE OF THE MONETIZED FORGONE BENEFITS, COST SAVINGS AND NET BENEFITS OF THE PROPOSED OIL AND NATURAL GAS RECONSIDERATION FROM 2019 THROUGH 2025

[Millions of 2016$]

	Present value	Equivalent annualized value
Benefits (Total Cost Savings)	$380 million	$66 million.
Costs (Forgone Domestic Climate Benefits)	$13.5 million	$2.3 million.
Net Benefits	$367 million	$64 million.
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 100,000 tons of VOC from 2019 through 2025. Health effects of HAP exposure from an increase of 3,800 tons of HAP from 2019 through 2025. Health effects of ozone exposure from an increase of 380,000 short tons of methane from 2019 through 2025. Visibility impairment. Vegetation effects.	

Estimates may not sum due to independent rounding.

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

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

C. Paperwork Reduction Act (PRA)

A summary of the information collection activities 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 NSPS OOOOa) under the PRA, and assigned EPA ICR Number 2523.02, can be found at 81 FR 35890. You can find a copy of the ICR in the 2016 NSPS OOOOa docket (EPA–HQ–OAR–2010–0505–7626). This proposed reconsideration revises the information collection activities of 2016 NSPS OOOOa. The revised information collection activities in this proposed rule have been submitted for approval to OMB under the PRA. The revised ICR document that the EPA prepared has been assigned EPA ICR number 2523.03. You can find a copy of the revised ICR in the docket for this rule.

The proposed changes to the 2016 NSPS OOOOa information collection activities would reduce the burden on the regulated industry associated with reporting and recordkeeping requirements. Proposed amendments to the reporting and recordkeeping requirements are presented in section 60.5420a. Other information collection activity reductions would result from proposed amendments that streamline and align monitoring requirements (and associated recordkeeping) in the rule.

The estimated average annual burden (averaged over the first 3 years after the effective date of the standards) for the recordkeeping and reporting requirements associated with the proposed amendments to subpart OOOOa for the estimated 2,893 owners and operators subject to the rule is 156,188 labor hours, with an average annual cost of $9,615,691 (2016$) over the three-year period. The information collection activities associated with the proposed amendments would result in an estimated average annual burden reduction of 8 percent compared to the previously-submitted 2016 NSPS OOOOa ICR (2016$).

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for the EPA's regulations in 40 CFR are listed in 40 CFR part 9.

Submit your comments on the Agency's need for this information, the accuracy of the provided revised burden estimates and any suggested methods for minimizing respondent burden to the EPA using the docket identified at the beginning of this rule. You may also send your ICR-related comments to OMB's Office of Information and Regulatory Affairs via email to *RIA_submissions@omb.eop.gov,* Attention: Desk Officer for the EPA. Since OMB is required to make a decision concerning the ICR between 30 and 60 days after receipt, OMB must receive comments no later than November 14, 2018. The EPA will respond to any ICR-related comments in the 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 proposed rule, including small entities, is reduced compared to the 2016 NSPS 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 of 1995 (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. This rule, if finalized, would primarily affect private industry and would not impose significant economic costs on state or local governments.

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. The 2016 NSPS OOOOa, as discussed in the RIA,[126] was anticipated to reduce emissions of methane, VOC, and HAPs, and some of the benefits of reducing these pollutants would have accrued to children. However, new data and analysis have affected expectations about the extent of the impact of the fugitive emissions program in the 2016 NSPS OOOOa on these benefits. For example, as previously discussed above in section VI.B.1. of this preamble, the EPA reviewed data provided by the petitioners, as well as other data that have become available since promulgation of the 2016 NSPS OOOOa. The EPA identified several areas of our analysis that raise concerns we have overestimated the emission reductions and, therefore, the cost effectiveness of the 2016 NSPS OOOOa fugitive emissions program. Based on this review, the EPA updated the model plants for non-low production well sites, re-examined the fugitive emissions estimation method for non-low production well sites and compressor stations, and recognized distinct operational characteristics of compressor stations. Furthermore, while the proposed amendment is expected to decrease the impact of the fugitive emissions program in the 2016 NSPS OOOOa on these benefits, as discussed in Chapter 1 of the RIA, the potential decrease in emission reduction (and thus the benefit) from the proposed amendment is minimal compared to the overall emission reduction that would continue to be achieved under the amended 40 CFR part 60, subpart OOOOa.

Moreover, the proposed 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 proposed 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. For the reasons stated above, we do not believe this small decrease in emission reduction 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. The basis for this determination can be found in the 2016 NSPS OOOOa (81 FR 35894).

J. National Technology Transfer and Advancement Act (NTTAA)

This action involves technical standards.[127] 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 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 voluntary consensus standards (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 sulfur dioxide. 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 proposed 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 NSPS OOOOa was anticipated to reduce emissions of methane, VOC, and HAPs, and some of the benefits of reducing these pollutants would have accrued to minority populations, low-income populations and/or indigenous peoples. However, new data and analysis have affected expectations about the extent of the impact of the fugitive emissions program in the 2016 NSPS OOOOa on these benefits. For example, as previously discussed above in section VI.B.1. of this preamble, the EPA reviewed data provided by the petitioners, as well as other data that have become available since promulgation of the 2016 NSPS OOOOa.

[126] See Chapter 4, ''Economic Impact Analysis and Distributional Assessments,'' of the RIA.

[127] These proposed technical standards are the same as those previously finalized at 40 CFR part 60, subpart OOOOa (81 FR 35824). 2016 NSPS OOOOa also previously incorporated by reference 10 technical standards. The incorporation by reference remains unchanged in this proposed action. See Docket ID Nos. EPA–HQ–OAR–2010–0505–7657 and EPA–HQ–OAR–2010–0505–7658.

The EPA identified several areas of our analysis that raise concerns we have overestimated the emission reductions and, therefore, the cost effectiveness of the 2016 NSPS OOOOa fugitive emissions program. Based on this review, the EPA updated the model plants for non-low production well sites, re-examined fugitive emissions from low production well sites, recognized the limitations in our emissions estimation method for non-low production well sites and compressor stations, and recognized distinct operational characteristics of compressor stations. Furthermore, while these communities may experience forgone benefits as a result of this action, as discussed in Chapter 1 of the RIA, the potential foregone emission reductions (and related benefits) from the proposed amendments is minimal compared to the overall emission reductions (and related benefits) from the 2016 NSPS.

Moreover, the proposed 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 proposed 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.

For the reasons stated above, the EPA believes that this proposed action is unlikely to have disproportionately high and adverse human health or environmental effects on minority populations, low-income populations and/or indigenous peoples. We note that the potential impacts of this proposed action 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.

List of Subjects in 40 CFR Part 60

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

Dated: September 11, 2018.

Andrew R. Wheeler,

Acting Administrator.

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

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

■ 1. The authority citation for part 60 continues to read as follows:

Authority: 42 U.S.C. 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 60.5365a is amended by revising paragraph (e) introductory text 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 with the potential for VOC emissions equal to or greater than 6 tpy as determined according to 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, as defined in § 60.5430a, determined for a 30-day period of production prior to the applicable emission determination deadline specified in this subsection. 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.

* * * * *

(i) * * *

(4) For purposes of § 60.5397a, a ''modification'' to a separate tank battery occurs when:

(i) Any of the actions in paragraphs § 60.5365a(i)(3)(i) through (iii) occurs at an existing separate tank battery;

(ii) A well sending production to an existing separate tank battery is modified, as defined in § 60.5365a(i)(3)(i) through (iii); 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 separate tank battery.

* * * * *

■ 3. Section 60.5375a is amended by revising paragraph (a)(1)(iii) introductory text and paragraph (f)(3)(ii) and adding paragraph (f)(4) to read as follows:

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

* * * * *

(a) * * *

(1) * * *

(iii) You must have a separator onsite or otherwise available for use at a centralized facility or well pad that services the well affected facility which is used to conduct the completion of the well affected facility. The separator must be available and ready to be used 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.

* * * * *

■ 4. Section 60.5385a is amended by revising paragraph (a)(1) to read as follows:

§ 60.5385a What GHG and 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 later.

* * * * *

■ 5. Section 60.5393a is amended by:

■ a. Revising paragraph (b) introductory text and paragraphs (b)(3), (b)(5), (b)(6) and (c);

■ b. Removing and reserving paragraphs (b)(1), (b)(2), and (f).

The revisions read as follows:

§ 60.5393a What GHG and 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) [Reserved]

(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.

(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)(2) of this section within 30 days of startup of the control device or within 30 days of the ability to route to a process.

* * * * *

(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 paragraph (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 an in-house engineer or a qualified professional engineer in accordance with paragraph (b)(5)(ii) of this section.

(ii) The following certification, signed and dated by the in-house engineer or qualified professional 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. I am aware that there are penalties for knowingly submitting false information.''

(iii) The assessment of technical feasibility 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, pressure losses and differentials in the closed vent system and the ability of the control device 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 in-house engineer or qualified professional engineer who signs the certification in accordance with paragraph (b)(2)(ii) of this section.

(iv) The owner or operator shall maintain the records § 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 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(c) and (d).

* * * * *

(f) [Reserved]

■ 6. Section 60.5397a is amended by:

■ a. Revising paragraph (a);

■ b. Revising paragraphs (c)(2);

■ c. Revising paragraph (c)(8) introductory text;

■ d. Adding paragraph (c)(8)(iii);

■ e. Revising paragraph (d);

■ f. Revising paragraph (f)(2);

■ g. Revising paragraph (g) introductory text;

■ h. Revising paragraphs (g)(1) and (2);

■ i. Removing and reserving paragraph (g)(5);

■ j. Adding paragraph (g)(6); and

■ k. Revising paragraph (h).

The revisions and additions read as follows:

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

* * * * *

(a) 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 ppm or greater using Method 21 of Appendix A–7 to this part.

* * * * *

(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).

* * * * *

(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 purposes of complying with the fugitive emissions monitoring program using Method 21 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 these readings by the initial calibration values 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 a sitemap or plot plan and the information in paragraph (d)(1)(i) or paragraphs (d)(1)(ii) through (iv):

(i) A defined observation path that ensures that all fugitive emissions components are within sight of the path. The observation path must account for interferences.

(ii) For closed vent systems regulated under this section, a narrative description of how the closed vent system will be monitored, including a description and the location of all fugitive emissions components located on the closed vent system. The sitemap or plot plan must include the location of each closed vent system.

(iii) For controlled storage vessels regulated under this section, a narrative description of how the storage vessel will be monitored including a description and location of all fugitive emissions components located on the controlled storage vessel. The sitemap or plot plan must include the location of each controlled storage vessel.

(iv) For all other fugitive emissions components not associated with a closed vent system or controlled storage vessel regulated under this section, a narrative description of how the fugitive emissions components will be monitored, including a description and location of all fugitive emissions components. The description and location of fugitive emissions components may be grouped by unit operations (*e.g.,* separator, heater/treater, glycol dehydrator). The sitemap or plot plan must include the location of each unit operation.

(2) If you are using Method 21, your plan must include a list of fugitive emissions components to be monitored and method for determining location of fugitive emissions components to be monitored in the field (*e.g.,* tagging, identification on a process and instrumentation diagram, etc.). If you are using optical gas imaging, you may comply with this requirement in lieu of paragraph (d)(1) of this section.

(3) Your fugitive emissions monitoring plan must include the written plan developed for all of the fugitive emission components designated as difficult-to-monitor in accordance with paragraph (g)(3) of this section, and the written plan for fugitive emission components designated as unsafe-to-monitor in accordance with paragraph (g)(4) of this section.

* * * * *

(f) * * *

(2) You must conduct an initial monitoring survey within 60 days of the startup of a new compressor station for each new collection of fugitive emissions components at the new compressor station or by June 3, 2017, whichever is later. For a modified collection of fugitive components at a compressor station, the initial monitoring survey must be conducted within 60 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 later.

(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), (4), and (6) of this section.

(1) A monitoring survey of each collection of fugitive emissions components at a well site within a company-defined area must be conducted at the frequencies specified in paragraphs (g)(1)(i) or (ii) of this section.

(i) At least annually for each collection of fugitive emissions components located at a well site with average combined oil and natural gas production for the wells at the site being greater than or equal to 15 barrels of oil equivalent (boe) per day averaged over the first 30 days of production, where boe equals cubic feet gas/5658.53. Consecutive annual monitoring surveys must be conducted at least 9 months apart and no more than 13 months apart.

(ii) At least once every other year (*i.e.,* biennial) for each collection of fugitive emissions components located at a well site with average combined oil and natural gas production for the wells at the site being less than 15 boe per day averaged over the first 30 days of production, where boe equals cubic feet gas/5658.53. Consecutive biennial monitoring surveys must be conducted no more than 25 months apart.

(2) Except as provided herein, a monitoring survey of the collection of fugitive emissions components at a compressor station within a company-defined area 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 6 months apart. Each compressor must be monitored while in operation (*i.e.,* not in stand-by mode) at least annually. 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) [Reserved]

(6) 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) Each identified source of fugitive emissions shall be repaired as soon as

practicable, but no later than 60 calendar days after detection of the fugitive emissions.

(2) A first attempt at repair shall be made no later than 30 calendar days after detection of the fugitive emissions.

(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, well shutdown, well shut-in, after a scheduled vent blowdown or within 2 years, whichever is earlier. For purposes of this requirement, 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 repaired fugitive emissions component must be resurveyed 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.

* * * * *

■ 7. Section 60.5398a is amended by revising paragraphs (a), (c), (d) and (f) to read as follows:

§ 60.5398a What are the alternative means of emission limitations for GHG and 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 GHG (in the form of a limitation on emission of methane) and VOC emissions at least equivalent to the reduction in GHG and 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.

* * * * *

(c) The Administrator will consider applications under this section from owners or operators of affected facilities, and manufacturers or vendors of leak detection technologies, or trade associations provided they are submitted in conjunction with an owner or operator.

(d) 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 is at least as equivalent as the relevant standards. At a minimum, the applicant must collect, verify, and submit field data to demonstrate the equivalence of the alternative means of emission limitation; the field data must encompass seasonal variations over the year to ensure that the technique works appropriately in different conditions that will be encountered during monitoring surveys. The field data may be supplemented with modeling analyses, test data, or other documentation. The application must include the following information:

(i) A description of the technology, technique, or process.

(ii) A description of the monitoring instrument or measurement technology used in the technology, technique, or process.

(iii) A description of performance based procedures (*i.e.,* method) and data quality indicators for precision and bias; the method detection limit of the technology, technique, or process.

(iv) For affected facilities under § 60.5397a, the action criteria and level at which a fugitive emission exists.

(v) Any initial and ongoing quality assurance/quality control measures necessary for maintaining the technology, technique, or process.

(vi) Timeframes for conducting ongoing quality assurance/quality control.

(vii) Field data verifying viability and detection capabilities of the technology, technique, or process. Test data, modeling analyses, or other documentation may be used to supplement field data.

(viii) Frequency of measurements and surveys conducted with the technology, technique, or process.

(ix) For continuous monitoring techniques, the minimum data availability.

(x) Sufficient data and other supporting documentation for determining the emissions reductions achieved or avoided by the technology, technique, or process.

(xi) Any restrictions for using the technology, technique, or process.

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

(xiii) Initial and continuous compliance procedures, including recordkeeping and reporting, if the compliance procedures are different than those specified in § 60.5397a(d).

(2) For each determination of equivalency requested, the emission reduction achieved by the design, equipment, work practice or operational requirements shall be demonstrated by field data, which can be supplemented with modeling analyses at an active

production site or test data at a controlled test environment or facility.

(3) For each technology, technique, or process for which a determination of equivalency is requested, the emission reduction achieved by the alternative means of emission limitation shall be demonstrated.

* * * * *

(f)(1) An application submitted under this section will be evaluated based on the field data, modeling analyses, and other documentation that was provided to demonstrate the equivalence of the alternative means of emission limitation under this section.

(2) The Administrator may condition the approval of the alternative means of emission limitation on requirements that may be necessary to ensure that the alternative will achieve at least equivalent emission reduction(s) as the reduction(s) achieved under the requirement(s) for which the alternative is being requested.

■ 8. Subpart OOOOa is amended by adding section 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 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 (g) through (n) of this section 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.

(a) The Administrator will consider applications for alternative fugitive emissions standards under this section based on state, local, or tribal programs that are currently in effect from any interested person, which includes, but is not limited to individuals, corporations, partnerships, associations, state, or municipalities.

(b) 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.

(c) After notice and opportunity for public comment, the Administrator will determine whether the requested alternative fugitive emissions standard will achieve at least equivalent emission reduction(s) in VOC and methane emissions as the reduction(s) achieved under the applicable requirement(s) for which an alternative is being requested, and will publish the determination in the **Federal Register**.

(d)(1) An application submitted under this section will be evaluated based on the documentation that was provided to demonstrate the equivalence of the alternative fugitive emissions standards under this section.

(2) The Administrator may condition the approval of the alternative fugitive emissions standards on requirements that may be necessary to ensure that the alternative will achieve at least equivalent emissions reduction(s) as the reduction(s) achieved under the requirements for which the alternative is being requested.

(e) 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) May be used by any owner or operator in meeting the relevant standards and requirements established for affected facilities under § 60.5397a.

(f)(1) An owner or operator must notify the Administrator before implementing one of the alternative fugitive emissions standards, as specified in § 60.5420a(a)(3).

(2) An owner or operator implementing one of the alternative fugitive emissions standards must include the information specified in § 60.5420a(b)(7) in the annual report and maintain the records specified by the specific alternative fugitive emissions standard for a period of at least 5 years.

(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 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 and GHG emissions through compliance with the monitoring, repair, and recordkeeping requirements in the California Code of Regulations, title 17, §§ 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) of this subpart.

(h) *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, §§ XII.L, effective June 30, 2018, or XVII.F, effective October 15, 2014 for well sites and January 1, 2015 for compressor stations, as an alternative to complying with the requirements in §§ 60.5397a(f)(1) and (2), (g)(1) through (4), (h), and (i) of this subpart, provided the monitoring instrument used is an optical gas imaging or a Method 21 instrument.

(i) *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) of this subpart, provided the monitoring instrument used is a Method 21 instrument and that the leak definition used for Method 21 monitoring is an instrument reading of 500 ppm or greater.

(j) *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) of this subpart, provided the monitoring instrument used is a Method 21 instrument and that the leak definition used for Method 21 monitoring is an instrument reading of 500 ppm or greater.

(k) *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 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) of this subpart, provided the monitoring instrument used is an optical gas imaging or a Method 21 instrument.

(l) *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) of this subpart, provided the monitoring instrument used is an optical gas imaging or a Method 21 instrument.

(m) *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 Tex. Admin. Code § 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) of this subpart, provided the monitoring instrument used is a Method 21 instrument and that the leak definition used for Method 21 monitoring is an instrument reading of 2,000 ppm or greater.

(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) of this subpart.

■ 9. Section 60.5400a is amended by revising paragraph (a) to read as follows:

§ 60.5400a What equipment leak GHG and VOC standards apply to affected facilities 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.

* * * * *

■ 10. Section 60.5401a is amended by revising paragraph (e) to read as follows:

§ 60.5401a What are the exceptions to the equipment leak GHG and 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), 60.482–11a(a), and paragraph (b)(1) of this section.

* * * * *

■ 11. Section 60.5410a is amended by:
■ a. Revising paragraph (c)(1);
■ b. Revising paragraphs (e)(2) through (5); and
■ c. Removing and reserving paragraph (e)(8).

The revisions 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?

* * * * *

(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 later.

* * * * *

(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 (b)(2), and you must collect the pneumatic pump emissions through a closed vent system that meets the requirements of § 60.5411a(c) and (d).

(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(c) and (d).

* * * * *

(8) [Reserved]

* * * * *

■ 12. Section 60.5411a is amended by:
■ a. Revising the introductory text;
■ b. Revising paragraph (a) introductory text;
■ c. Revising paragraph (a)(1);
■ d. Revising paragraph (c) introductory text;
■ e. Revising paragraph (c)(1);
■ f. Revising paragraph (d)(1); and
■ g. Removing and reserving paragraph (e).

The revisions 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) Closed vent system requirements for storage vessel and 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 material in the storage vessel or pneumatic pump to a control device or to a process. For storage vessels, the closed vent system must route all gases, vapors, and fumes to a control device that meets the requirements specified in § 60.5412a(c) and (d).

* * * * *

(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 an in-house engineer or a qualified professional engineer in accordance with paragraphs (d)(1)(i) and (ii) of this section.

(i) You must provide the following certification, signed and dated by an in-house engineer or a qualified professional 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. I am aware that there are penalties for knowingly submitting false information.''

(ii) The assessment shall be prepared under the direction or supervision of an in-house engineer or a qualified professional engineer who signs the certification in paragraph (d)(1)(i) of this section.

* * * * *

(e) [Reserved]

■ 13. Section 60.5412a is amended by
■ a. Revising paragraph (a)(1) introductory text;
■ b. Revising paragraph (a)(1)(iv);
■ c. Revising paragraph (c) introductory text;
■ d. Revising paragraph (d)(1)(iv) introductory text; and paragraph (d)(1)(iv)(D).

The revisions 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 (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.

* * * * *

■ 14. Section 60.5413a is amended by revising paragraph (d)(5)(i) introductory text and paragraphs (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 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) CBIO Room 521; 109 T.W. Alexander Drive; RTP, NC 27711. The same file with the CBI omitted must be submitted to *Oil_and_Gas_PT@EPA.GOV.*

* * * * *

■ 15. Section 60.5415a is amended by:
■ a. Revising paragraph (b) introductory text;
■ b. Revising paragraph (b)(3);
■ c. Removing and reserving paragraph (b)(4);
■ d. Revising paragraph (c)(1); and
■ e. Revising paragraph (h)(2).

The revisions 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) 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.

(4) [Reserved]

(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 later.

* * * * *

(h) * * *

(2) You must repair each identified source of fugitive emissions as required in § 60.5397a(h).

* * * * *

■ 16. Section 60.5416a is amended by:

■ a. Revising the introductory text;

■ b. Revising paragraph (a) introductory text;

■ c. Revising paragraph (a)(4) introductory text;

■ d. Revising paragraph (c) introductory text; and

■ e. Removing and reserving paragraph (d).

The revisions 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 (c) 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 paragraphs (a)(4)(i) or (ii) of this section.

* * * * *

(c) *Cover and closed vent system inspections for pneumatic pump or 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 (c)(2) of this section. You must also comply with the requirements of (c)(3) through (7) of this section.

* * * * *

(d) [Reserved]

■ 17. Section 60.5417a is amended by revising 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?

* * * * *

(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 (h)(4) of this section.

* * * * *

■ 18. Section 60.5420a is amended by:

■ a. Revising paragraph (a)(1);

■ b. Adding paragraph (a)(3);

■ c. Revising paragraph (b) introductory text;

■ d. Revising paragraph (b)(2);

■ e. Revising paragraph (b)(3) introductory paragraph;

■ f. Revising paragraphs (b)(3)(ii) through (iv);

■ g. Adding paragraph (b)(3)(v);

■ h. Revising paragraph (b)(4);

■ i. Revising paragraphs (b)(5)(i) through (iii);

■ j. Revising paragraph (b)(6) introductory text;

■ k. Revising paragraphs (b)(6)(iii) and (vii);

■ l. Adding paragraphs (b)(6)(viii) and (ix);

■ m. Revising paragraph (b)(7);

■ n. Revising paragraph (b)(8) introductory text;

■ o. Revising paragraph (b)(8)(iii);

■ p. Adding paragraph (b)(8)(iv);

■ q. Revising paragraph (b)(9)(i);

■ r. Revising paragraphs (b)(11) through (13);

■ s. Adding paragraph (b)(14);

■ t. Revising paragraph (c) introductory text;

■ u. Revising paragraph (c)(1) introductory text;

■ v. Revising paragraph (c)(1)(ii);

■ w. Revising paragraph (c)(1)(iii) introductory text;

■ x. Revising paragraphs (c)(1)(iii)(A) and (B);

■ y. Revising paragraph (c)(1)(iii)(C)(*1*);

■ z. Revising paragraphs (c)(1)(iv), (c)(1)(vi)(B), and (c)(1)(vii);

■ aa. Revising paragraph (c)(2) introductory text;

■ bb. Revising paragraphs (c)(2)(vi)(D) and (E);

■ cc. Revising paragraph (c)(2)(vii);

■ dd. Adding paragraph (c)(2)(viii);

■ ee. Revising paragraphs (c)(3)(i) and (iii);

■ ff. Revising paragraphs (c)(4)(i) and (v);

■ gg. Revising paragraph (c)(5) introductory text;

■ hh. Revising paragraphs (c)(5)(iii) and (v);

■ ii. Revising paragraph (c)(5)(vi) introductory text;

■ jj. Revising paragraphs (c)(5)(vi)(F)(*4*) and (c)(5)(vi)(G);

■ kk. Adding paragraphs (c)(5)(vi)(H) and (c)(5)(vii);

■ ll. Revising paragraphs (c)(6) through (9);

■ mm. Revising paragraph (c)(15);

■ nn. Revising paragraphs (c)(16)(ii) and (iv); and

■ oo. Adding paragraph (c)(18)

The revisions and additions read as follows:

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

(a) * * *

(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 at an onshore natural gas processing plant, 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, or collection of fugitive emissions components at a well site or collection of fugitive emissions components at a compressor station, you are not required to submit the notifications required in § 60.7(a)(1), (3), and (4) and § 60.15(d).

* * * * *

(3) An owner or operator electing to comply with the provisions of § 60.5399a shall notify the Administrator of the alternative standard selected 90 days before implementing any of the provisions.

(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.

* * * * *

(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 (b)(2)(xiv) of this section, if applicable. In lieu of submitting the records specified in paragraph (b)(2)(i) through (b)(2)(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 permanent separators, the records specified in paragraphs (b)(2)(i) through (b)(2)(iv) and (b)(2)(vi) through (b)(2)(xiv) of this section. For each well affected facility that is subject to § 60.5375a(g), the record specified in paragraph (b)(2)(xv) of this section.

(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) US Well ID.

(iv) The date and time of the onset of flowback following hydraulic fracturing or refracturing.

(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.

* * * * *

(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, how the defect or leak was repaired and 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 § 60.5413a(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 later. 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, how the defect or leak was repaired 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) * * *

(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.

* * * * *

(iii) For each deviation that occurred during the reporting period and recorded as specified in paragraph (c)(5)(iii) of this section, the date and time the deviation began, duration of the deviation and a description of the deviation.

* * * * *

(vii) 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 § 60.5413a(e), the information in paragraphs (b)(6)(vii)(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.

(viii) 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.

(ix) If required to comply with § 60.5395a(b)(1), the information in paragraphs (b)(6)(ix)(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, how the defect or leak was repaired 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).

(7) For the collection of fugitive emissions components at each well site and the collection of fugitive emissions components at each compressor station within the company-defined area, the information specified in paragraphs (b)(7)(i) and (ii) of this section.

(i)(A) 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.

(B) 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 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 a statement that all major production and processing equipment has been removed from the well site, the date of the removal of the last piece of major production and processing equipment, and if the well site is still producing to another site, the well ID or separate tank battery ID receiving the production.

(D) For each collection of fugitive emissions components at a well site where you previously reported under paragraph (b)(7)(i)(C) 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.

(E) For each new collection of fugitive emissions components at a well site where the average combined oil and natural gas production for the wells at the site is less than 15 boe per day, you must submit the combined oil and natural gas production in boe for the wells at the site, averaged over the first 30 days of production.

(ii) For each fugitive emissions monitoring survey performed during the annual reporting period, the information specified in paragraphs (b)(7)(ii)(A) through (L) of this section.

(A) Date of the survey.

(B) Name or unique ID of operator(s) performing survey.

(C) Ambient temperature, sky conditions, and maximum wind speed at the time of the survey.

(D) Monitoring instrument used.

(E) Any deviations from the monitoring plan elements under § 60.5397a(c)(1), (2), (7), and (8)(i) or a statement that there were no deviations from these elements of the monitoring plan.

(F) Number and type of components for which fugitive emissions were detected.

(G) Number and type of fugitive emissions components that were not repaired as required in § 60.5397a(h).

(H) Number and type of difficult-to-monitor and unsafe-to-monitor fugitive emission components monitored.

(I) The date of successful repair of the fugitive emissions component.

(J) Number and type of fugitive emission components currently on delay of repair and explanation for each delay of repair.

(K) Type of instrument used to resurvey a repaired fugitive emissions component that could not be repaired during the initial fugitive emissions finding, if the type of instrument is different from the type used during the initial fugitive emissions finding.

(L) Date of planned shutdown(s) that occurred during the reporting period if there are any components that have been placed on delay of repair.

(8) For each pneumatic pump affected facility, the information specified in paragraphs (b)(8)(i) through (iv) of this section.

* * * * *

(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(c);

(B) Each defect or leak identified during each inspection, how the defect or leak was repaired 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) * * *

(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). (CEDRI can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*).) Performance test data must be submitted in a file format generated through the use of the EPA's ERT or an alternate electronic file format consistent with the extensible markup language (XML) schema listed on the EPA's ERT website. If you claim that some of the performance test information being submitted is confidential business information (CBI), you must submit a complete file generated through the use of the EPA's ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT 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.

* * * * *

(11) You must submit reports to the EPA via the CEDRI. (CEDRI can be accessed through the EPA's CDX (*https://cdx.epa.gov/*).) You must use the appropriate electronic report in CEDRI for this subpart or an alternate electronic file format consistent with the extensible markup language (XML) schema listed on the CEDRI 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, 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. If you claim that some of the information required to be submitted via CEDRI is CBI, 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, Measurement Policy 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.

(12) You must submit the certification signed by the in-house engineer or qualified professional 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, and due to a planned or actual outage of either the EPA's CEDRI or CDX systems within the period of time beginning 5 business days prior to the date that the submission is due, you will be or are precluded from accessing CEDRI or CDX and submitting a required report within the time prescribed, you may assert a claim of EPA system outage for failure to timely comply with the reporting requirement. 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. You must provide to the Administrator a written description identifying the date, time and length of the outage; a rationale for attributing the delay in reporting beyond the regulatory deadline to the EPA system outage; describe the measures taken or to be taken to minimize the delay in reporting; and identify a 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. In any circumstance, the report must be submitted electronically as soon as possible after the outage is resolved. 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.

(14) If you are required to electronically submit a report through CEDRI in the EPA's CDX and a force majeure event is about to occur, occurs, or has occurred within the period of time beginning 5 business days prior to the date the submission is due, the owner or operator may assert a claim of force majeure for failure to timely comply with the reporting requirement. 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). If you intend to assert a claim of force majeure, 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. You must provide to the Administrator a written description of the force majeure event and a rationale for attributing the delay in reporting beyond the regulatory deadline to the

force majeure event; describe the measures taken or to be taken to minimize the delay in reporting; and identify a 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. In any circumstance, the reporting must occur as soon as possible after the force majeure event occurs. 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.

(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 permanent separators the date and time of each attempt to direct flowback to a separator is not required.

* * * * *

(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 that subparagraph.

(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) * * *

(*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.

* * * * *

(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.

* * * * *

(vi) * * *

(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;

* * * * *

(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 § 60.5413a(e) and used to comply with § 60.5380a(a)(1) for each centrifugal compressor.

* * * * *

(vi) * * *

(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) * * *

(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 later. Alternatively, a statement that emissions from the rod packing are being routed to a process through a closed vent system under negative pressure.

* * * * *

(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) * * *

(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.

* * * * *

(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.

* * * * *

(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.

* * * * *

(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 § 60.5413a(e) and used to comply with § 60.5395a(a)(2) for each storage vessel.

* * * * *

(F) * * *

(*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.

* * * * *

(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) for centrifugal compressors and reciprocating compressors, or § 60.5416a(c)(1) for storage vessels and pneumatic pumps as required in paragraphs (c)(6)(i) through (iii) of this section.

(i) A record of each closed vent system inspection. 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 detected during inspections required by § 60.5416a(a)(1) and (2) or § 60.5416a(c)(1), 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), 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 or pneumatic pumps 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 § 60.5416a(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), 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) If you are subject to the closed vent system no detectable emissions requirements of § 60.5416a(b) for centrifugal compressors or reciprocating compressors, you must prepare and maintain the records required in paragraphs (c)(9)(i) through (iii) of this section.

(i) A record of each closed vent system 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 monitoring survey.

(ii) For each leak detected during inspections required by § 60.5416a(b), you must record the location of the leak, the maximum concentration reading obtained using Method 21, the date of detection, the corrective action taken the repair the leak, and the date the repair to correct the leak is completed.

(iii) If repair of the leak 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.

* * * * *

(15) For each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a compressor station, the records identified in paragraphs (c)(15)(i) through (vii) 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 compressor station.

(ii) 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, 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, 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, the date that the first piece of major production and processing equipment is added back to the well site.

(iii) For each collection of fugitive emissions components at a well site that is monitored annually under (g)(1)(ii)(B), the records identified in paragraphs (c)(15)(iii)(A) and (B) of this section.

(A) The average daily combined oil and natural gas production for the well site during the first 30 days of production; and

(B) A description of the methodology used to calculate the daily average production for the well site.

(iv) The fugitive emissions monitoring plan as required in § 60.5397a(b), (c), and (d).

(v) The records of each monitoring survey as specified in paragraphs (c)(15)(v)(A) through (L) of this section.

(A) Date of the survey.

(B) Beginning and end time of the survey.

(C) Name of operator(s) performing survey. If you choose to report the unique ID of the operator(s) performing the survey in lieu of the operator(s) name, you must keep a record linking the unique ID to the operator(s) name. You must note the training and experience of the operator(s).

(D) Monitoring instrument used.

(E) When optical gas imaging is used to perform the survey, one or more digital photographs or videos, captured from the optical gas imaging instrument used for monitoring, of each required monitoring survey being performed. The digital photograph must include the date the photograph was taken and the latitude and longitude of the collection of fugitive emissions components at a well site or collection of fugitive emissions components at a compressor station imbedded within or stored with the digital file. As an alternative to imbedded latitude and longitude within the digital file, the digital photograph or video may consist of an image of the monitoring survey being performed with a separately operating GPS device within the same digital picture or video, provided the latitude and longitude output of the GPS unit can be clearly read in the digital image. Digital photographs or video recorded under paragraph (c)(15)(v)(K)(*1*) of this section can be used to meet this requirement, as long as the photograph or video is taken with the optical gas imaging instrument, includes the date and the latitude and longitude are either imbedded or visible in the picture.

(F) Fugitive emissions component identification when Method 21 of appendix A–7 of this part is used to perform the monitoring survey or when optical gas imaging is used to perform the monitoring survey and the owner or operator chooses to comply with § 60.5397a(d)(2) in lieu of § 60.5397a (d)(1).

(G) Ambient temperature, sky conditions, and maximum wind speed at the time of the survey.

(H) Any deviations from the monitoring plan or a statement that there were no deviations from the monitoring plan.

(I) Documentation of each fugitive emission, including the information specified in paragraphs (c)(15)(v)(I)(*1*) through (*3*) of this section.

(*1*) Location.

(*2*) Component ID and type of fugitive emissions component.

(*3*) Instrument reading of each fugitive emissions component that requires repair when Method 21 is used for monitoring.

(J) Number and type of fugitive emissions components that were not repaired as required in § 60.5397a(h).

(K) For each component that cannot be repaired during the monitoring survey when the fugitive emissions were initially found:

(*1*) Number and type of components that were tagged or a digital photograph or video of each fugitive emissions component. The digital photograph or video must clearly identify the location of the component that must be repaired. Any digital photograph or video required under this paragraph can also be used to meet the requirements under paragraph (c)(15)(ii)(E) of this section, as long as the photograph or video is taken with the optical gas imaging instrument, includes the date and the latitude and longitude are either imbedded or visible in the picture.

(*2*) The date and repair methods applied in each attempt to repair the fugitive emissions components.

(*3*) The date of successful repair of the fugitive emissions component.

(*4*) The date of each resurvey and instrumentation used to resurvey a repaired fugitive emissions component that could not be repaired during the initial fugitive emissions finding.

(*5*) Identification of each fugitive emission component placed on delay of repair and explanation for each delay of repair.

(L) Records of calibrations for the instrument used during the monitoring survey.

(vi) Date of planned shutdowns that occur while there are any components that have been placed on delay of repair.

(16) * * *

(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.

* * * * *

(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).

* * * * *

(18) A copy of each performance test submitted under paragraph (b)(9) of this section.

■ 19. Section 60.5422a is amended by revising paragraphs (a) and (b), and paragraph (c) introductory text to read as follows:

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

(a) You must comply with the requirements of paragraphs (b) and (c) of this section in addition to the requirements of § 60.487a(a), (b)(1) through (3), (b)(5), (c)(2)(i) through (iv), and (c)(2)(vii) through (viii). You must submit semiannual reports to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI). (CEDRI can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*).) Use the appropriate electronic report in CEDRI for this subpart or an alternate electronic file format consistent with the extensible markup language (XML) schema listed on the CEDRI 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 (b)(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 (c)(2)(vii) through (viii):

* * * * *

■ 20. Section 60.5423a is amended by revising 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 at onshore natural gas processing plants?

* * * * *

(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.

* * * * *

■ 21. Section 60.5430a is amended by:

■ a. Revising the definitions for ''capital expenditure'', ''certifying official'', ''flowback'', ''fugitive emissions component'', ''low pressure well'', ''maximum average daily throughput'', ''startup of production'', and ''well site'';

■ b. Adding in alphabetical order the definitions for ''coil tubing cleanout'', ''custody meter'', ''custody meter assembly'', ''first attempt at repair'', ''major production and processing equipment'', ''permanent separator'', ''plug drill-out'', ''repaired'', ''screenout'', ''UIC Class II oilfield disposal well'', and ''wellhead only well site''; and

■ c. Removing the definition for ''greenfield 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 equations: $Y = 1.0 - 0.575 \log X$, where X is 2015 minus the year of construction, and $Y = 1.0$ when the year of construction is 2015; 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 Clean Air Act or the regulations promulgated thereunder are concerned; or

(ii) The designated representative for any other purposes under part 60.

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.

* * * * *

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 of methane or VOC 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 methane or 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 compressors, glycol dehydrators, heater/treaters, pneumatic pumps, pneumatic controllers, 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 throughput, determined as described in (1) or (2), to an individual storage vessel over the days that production is routed to that storage vessel during the 30-day evaluation period specified in § 60.5365a(e)(1).

(1) 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

(2) 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.

* * * * *

Permanent separator means a separator that handles flowback from a well or wells beginning when the flowback period begins and continuing to the startup of production.

Plug drill-out means the removal of a plug (or plugs) that was used to conducted hydraulic fracturing in 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 of this subpart and is 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 the first attempt to clear proppant from the wellbore through flowing the well to a fracture tank in order to achieve maximum velocity and carry 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 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.

* * * * *

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 and (2) the flange 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.

* * * * *

■ 22. Table 3 to Subpart OOOOa of Part 60 is amended to revise the explanations for sections 60.8 and 60.15 general provisions citation entries 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	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.
* * * * * * *			

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