ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[EPA–HQ–OAR–2010–0505; FRL–9929–75–OAR]

RIN 2060–AS30

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

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: This action proposes to amend the new source performance standards (NSPS) for the oil and natural gas source category by setting standards for both methane and volatile organic compounds (VOC) for certain equipment, processes and activities across this source category. The Environmental Protection Agency (EPA) is including requirements for methane emissions in this proposal because methane is a greenhouse gas (GHG), and the oil and natural gas category is currently one of the country's largest emitters of methane. In 2009, the EPA found that by causing or contributing to climate change, GHGs endanger both the public health and the public welfare of current and future generations. The EPA is proposing both methane and VOC standards for several emission sources not currently covered by the NSPS and proposing methane standards for certain emission sources that are currently regulated for VOC. The proposed amendments also extend the current VOC standards to the remaining unregulated equipment across the source category and additionally establish methane standards for this equipment. Lastly, amendments to improve implementation of the current NSPS are being proposed which result from reconsideration of certain issues raised in petitions for reconsideration that were received by the Administrator on the August 16, 2012, final NSPS for the oil and natural gas sector and related amendments. Except for the implementation improvements and the setting of standards for methane, these amendments do not change the requirements for operations already covered by the current standards.

DATES: Comments. Comments must be received on or before November 17, 2015. Under the Paperwork Reduction Act(PRA), comments on the information collection provisions are best assured of consideration if the Office of Management and Budget (OMB) receives a copy of your comments on or before November 17, 2015. The EPA will hold public hearings on the proposal. Details will be announced in a separate announcement.

ADDRESSES: Submit your comments, identified by Docket ID Number EPA–HQ–OAR–2010–0505, to the Federal eRulemaking Portal: *http://www.regulations.gov.* Follow the online instructions for submitting comments. Once submitted, comments cannot be edited or withdrawn. The EPA may publish any comment received to its public docket. Do not submit electronically any information you consider to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Multimedia submissions (audio, video, etc.) must be accompanied by a written comment. The written comment is considered the official comment and should include discussion of all points you wish to make. The EPA will generally not consider comments or comment contents located outside of the primary submission (i.e. on the web, cloud, or other file sharing system). For additional submission methods, the full EPA public comment policy, information about CBI or multimedia submissions, and general guidance on making effective comments, please visit *http://www2.epa.gov/dockets/commenting-epa-dockets.*

Instructions: All submissions must include agency name and respective docket number or Regulatory Information Number (RIN) for this rulemaking. Direct your comments to Docket ID Number EPA–HQ–OAR–2010–0505. The EPA's policy is that all comments received will be included in the public docket without change and may be made available online at *www.regulations.gov,* including any personal information provided, unless the comment includes information claimed to be confidential business information (CBI) or other information whose disclosure is restricted by statute. Do not submit information that you consider to be CBI or otherwise protected through *www.regulations.gov* or email. (See section III.B below for instructions on submitting information claimed as CBI.) The *www.regulations.gov* Web site is an ''anonymous access'' system, which means the EPA will not know your identity or contact information unless you provide it in the body of your comment. If you submit an electronic comment through *www.regulations.gov,* the EPA recommends that you include your name and other contact information in the body of your comment and with any disk or CD–ROM you submit. If the EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, the EPA may not be able to consider your comment. If you send an email comment directly to the EPA without going through *www.regulations.gov,* your email address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the Internet. Electronic files should avoid the use of special characters, any form of encryption and be free of any defects or viruses. For additional information about the EPA's public docket, visit the EPA Docket Center homepage at: *www.epa.gov/epahome/dockets.htm.*

Docket: The EPA has established a docket for this rulemaking under Docket ID Number EPA–HQ–OAR–2010–0505. All documents in the docket are listed in the *www.regulations.gov* index. Although listed in the index, some information is not publicly available, *e.g.,* CBI or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy. Publicly available docket materials are available either electronically in *www.regulations.gov* or in hard copy at the EPA Docket Center, EPA WJC West Building, Room Number 3334, 1301 Constitution Avenue NW., Washington, DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the EPA Docket Center is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: For information concerning this action, or for other information concerning the EPA's Oil and Natural Gas Sector regulatory program, contact Mr. Bruce Moore, Sector Policies and Programs Division (E143–05), Office of Air Quality Planning and Standards, Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone number: (919) 541–5460; facsimile number: (919) 541–3470; email address: *moore.bruce@epa.gov.*

SUPPLEMENTARY INFORMATION: *Outline.* The information presented in this preamble is organized as follows:

I. Preamble Acronyms and Abbreviations

Several acronyms and terms are included in this preamble. While this may not be an exhaustive list, to ease the reading of this preamble and for reference purposes, the following terms and acronyms are defined here:

ANGA America's Natural Gas Alliance
API American Petroleum Institute
bbl Barrel
BID Background Information Document
BOE Barrels of Oil Equivalent
bpd Barrels Per Day
BSER Best System of Emissions Reduction
BTEX Benzene, Toluene, Ethylbenzene and Xylenes
CAA Clean Air Act
CFR Code of Federal Regulations
CPMS Continuous Parametric Monitoring Systems
EIA Energy Information Administration
EPA Environmental Protection Agency
GOR Gas to Oil Ratio
HAP Hazardous Air Pollutants
HPD HPDI, LLC
LDAR Leak Detection and Repair
Mcf Thousand Cubic Feet
NEI National Emissions Inventory
NEMS National Energy Modeling System
NESHAP National Emissions Standards for Hazardous Air Pollutants
NSPS New Source Performance Standards
NTTAA National Technology Transfer and Advancement Act of 1995
OAQPS Office of Air Quality Planning and Standards
OGI Optical Gas Imaging
OMB Office of Management and Budget
OVA Olfactory, Visual and Auditory
PRA Paperwork Reduction Act
PTE Potential to Emit
REC Reduced Emissions Completion
RFA Regulatory Flexibility Act
RIA Regulatory Impact Analysis
scfh Standard Cubic Feet per Hour
scfm Standard Cubic Feet per Minute
SISNOSE Significant Economic Impact on a Substantial Number of Small Entities
tpy Tons per Year
TSD Technical Support Document
TTN Technology Transfer Network
UMRA Unfunded Mandates Reform Act
VCS Voluntary Consensus Standards
VOC Volatile Organic Compounds
VRU Vapor Recovery Unit

II. Executive Summary

A. Purpose of the Regulatory Action

The purpose of this action is to propose amendments to the NSPS for the oil and natural gas source category. To date the EPA has established standards for emissions of VOC and sulfur dioxide (SO_2) for several operations in the source category. In this action, the EPA is proposing to amend the NSPS to include standards for reducing methane as well as VOC emissions across the oil and natural gas source category (*i.e.,* production, processing, transmission and storage). The EPA is including requirements for methane emissions in this proposal because methane is a GHG and the oil and natural gas category is currently one of the country's largest emitters of methane. In 2009, the EPA found that by causing or contributing to climate change, GHGs endanger both the public health and the public welfare of current and future generations.1 The proposed amendments would require reduction of methane as well as VOC across the source category.

In addition, the proposed amendments include improvements to several aspects of the existing standards related to implementation. These improvements and the setting of standards for methane are a result of reconsideration of certain issues raised in petitions for reconsideration that were received by the Administrator on the August 16, 2012, NSPS (77 FR 49490) and on the September 13, 2013, amendments (78 FR 58416). Except for these implementation improvements, these proposed amendments do not change the requirements for operations and equipment already covered by the current standards.

B. Summary of the Major Provisions of the Regulatory Action

The proposed amendments include standards for methane and VOC for certain new, modified and reconstructed equipment, processes and activities across the oil and natural gas source category. These emission sources include those that are currently unregulated under the current NSPS (hydraulically fractured oil well completions, pneumatic pumps and fugitive emissions from well sites and compressor stations); those that are currently regulated for VOC but not for methane (hydraulically fractured gas well completions, equipment leaks at natural gas processing plants); and certain equipment that are used across the source category, but which the current NSPS regulates VOC emissions from only a subset of these equipment (pneumatic controllers, centrifugal compressors, reciprocating compressors), with the exception of compressors located at well sites.

Based on the EPA's analysis (see section VIII), we believe it is important to regulate methane from the oil and gas sources already regulated for VOC emissions to provide more consistency across the category, and that the best system of emission reduction (BSER) for methane for all these sources is the same as the BSER for VOC. Accordingly, the current VOC standards also reflect the BSER for methane reduction for the same emission sources. In addition, with respect to equipment used category-wide of which only a subset of those equipment are covered under the NSPS VOC standards (i.e., pneumatic controllers, and compressors located other than at well sites), EPA's analysis shows that the BSER for reducing VOC from the remaining unregulated equipment to be the same as the BSER for those currently regulated. The EPA is therefore proposing to extend the current VOC standards for these equipment to the remaining unregulated equipment.

The additional sources for which we are proposing methane and VOC standards were evaluated in the 2014 white papers (EPA Docket Number EPA–HQ–OAR–2014–0557). The papers summarized the EPA's understanding of VOC and methane emissions from these sources and also presented the EPA's understanding of mitigation techniques (practices and equipment) available to reduce these emissions, including the efficacy and cost of the technologies and the prevalence of use in the industry. The EPA received 26 submissions of peer review comments on these papers, and more than 43,000 comments from the public. The information gained through this process has improved the EPA's understanding of the methane and VOC emissions from these sources and the mitigation techniques available to control them.

The EPA has also received extensive and helpful input from state, local and tribal governments experienced in these operations, industry organizations, individual companies and others with data and experience. This information has been immensely helpful in determining appropriate standards for the various sources we are proposing to regulate. It has also helped the EPA design this proposal so as to complement, not complicate, existing state requirements. EPA acknowledges that a state may have more stringent state requirements (*e.g.*, fugitives monitoring and repair program). We believe that affected sources already complying with more stringent state requirements may also be in compliance with this rule. We solicit comment on how to determine whether existing state requirements (*i.e.*, monitoring, record keeping, and reporting) would demonstrate compliance with this federal rule.

During development of these proposed requirements, we were mindful that some facilities that will be subject to the proposed EPA standards will also be subject to current or future requirements of the Department of Interior's Bureau of Land Management (BLM) rules covering production of natural gas on Federal lands. We believe, to minimize confusion and unnecessary burden on the part of owners and operators, it is important that the EPA requirements not conflict with BLM requirements. As a result, EPA and BLM have maintained an ongoing dialogue during development of this action to identify opportunities for alignment and ways to minimize potential conflicting requirements and will continue to coordinate through the agencies' respective proposals and final rulemakings.

Following are brief summaries of these sources and the proposed standards.

Compressors. The EPA is proposing a 95 percent reduction of methane and VOC emissions from wet seal centrifugal compressors across the source category (except for those located at well sites).[2] For reciprocating compressors across the source category (except for those located at well sites), the EPA is proposing to reduce methane and VOC emissions by requiring that owners and/or operators of these compressors replace the rod packing based on specified hours of operation or elapsed calendar months or route emissions from the rod packing to a process through a closed vent system under negative pressure. See sections VIII.B and C of this preamble for further discussion.

Pneumatic controllers. The EPA is proposing a natural gas bleed rate limit of 6 standard cubic feet per hour (scfh) to reduce methane and VOC emissions from individual, continuous bleed, natural gas-driven pneumatic controllers at locations across the source category other than natural gas processing plants. At natural gas processing plants, the proposed rule regulates methane and VOC emissions by requiring natural gas-operated pneumatic controllers to have a zero natural gas bleed rate, as in the current NSPS. See section VIII.D of this preamble for further discussion.

Pneumatic pumps. The proposed standards for pneumatic pumps would apply to certain types of pneumatic pumps across the entire source category. At locations other than natural gas processing plants, we are proposing that the methane and VOC emissions from natural gas-driven chemical/methanol pumps and diaphragm pumps be reduced by 95 percent if a control device is already available on site. At natural gas processing plants, the proposed standards would require the methane and VOC emissions from natural gas-driven chemical/methanol pumps and diaphragm pumps to be zero. See section VIII.E of this preamble for further discussion.

Hydraulically fractured oil well completions. For subcategory 1 wells (non-wildcat, non-delineation wells), we are proposing that for hydraulically fractured oil well completions, owners and/or operators use reduced emissions completions, also known as ''RECs'' or ''green completions,'' to reduce methane and VOC emissions and maximize natural gas recovery from well completions. To achieve these reductions, owners and operators of hydraulically fractured oil wells must use RECs in combination with a completion combustion device. As is specified in the rule for hydraulically fractured gas well completions, the rule proposed here does not require RECs where their use is not feasible (*e.g.*, if it technically infeasible for a separator to function). For subcategory 2 wells (wildcat and delineation wells), we are proposing that for hydraulically fractured oil well completions, owners and/or operators use a completion combustion device to reduce methane and VOC emissions. The proposed standards for hydraulically fractured oil well completions are the same as the requirements finalized for hydraulically fractured gas well completions in the 2012 NSPS and as amended in 2014 (see 79 FR 79018, December 31, 2014). See section VIII.F of this preamble for further discussion.

Fugitive emissions from well sites and compressor stations. We are proposing that new and modified well sites and compressor stations (which include the transmission and storage segment and the gathering and boosting segment) conduct fugitive emissions surveys

[2] During the development of the 2012 NSPS, our data indicatedd that there were no centrifugal compressors located at well sites. Since the 2012 NSPS, we have not received information that would change our understanding that there are no centrifugal compressors in use at well sites.

semiannually with optical gas imaging (OGI) technology and repair the sources of fugitive emissions within 15 days that are found during those surveys. We are also co-proposing OGI monitoring surveys on an annual basis for new and modified well sites, and requesting comment on OGI monitoring surveys on a quarterly basis for both well sites and compressor stations. Fugitive emissions can occur immediately on startup of a newly constructed facility as a result of improper makeup of connections and other installation issues. In addition, during ongoing operation and aging of the facility, fugitive emissions may occur. Under this proposal, the required survey frequency would decrease from semiannually to annually for sites that find fugitive emissions from fewer than one percent of their fugitive emission components during a survey, while the frequency would increase from semiannually to quarterly for sites that find fugitive emissions from three percent or more of their fugitive emission components during a survey. We recognize that subpart W already requires annual fugitives reporting for certain compressor stations that exceed the 25,000 Metric Ton CO_2e threshold, and request comments on the overlap of these reporting requirements.

Building on the 2012 NSPS, the EPA intends to continue to encourage corporate-wide voluntary efforts to achieve emission reductions through responsible, transparent and verifiable actions that would obviate the need to meet obligations associated with NSPS applicability, as well as avoid creating disruption for operators following advanced responsible corporate practices. Based on this concept, we solicit comment on criteria we can use to determine whether and under what conditions well sites and other emission sources operating under corporate fugitive monitoring plans can be deemed to be meeting the equivalent of the NSPS standards for well site fugitive emissions such that we can define those regimes as constituting alternative methods of compliance or otherwise provide appropriate regulatory streamlining. We also solicit comment on how to address enforceability of such alternative approaches (i.e., how to assure that these well sites are achieving, and will continue to achieve, equal or better emission reduction than our proposed standards).

Other reconsideration issues being addressed. The EPA is granting reconsideration of a number of issues raised in the administrative reconsideration petitions and, where appropriate, is proposing amendments to address such issues. These issues are as follows: Storage vessel control device monitoring and testing provisions, initial compliance requirements in § 60.5411(c)(3)(i)(A) for a bypass device that could divert an emission stream away from a control device, recordkeeping requirements of § 60.5420(c) for repair logs for control devices failing a visible emissions test, clarification of the due date for the initial annual report under the 2012 NSPS, flare design and operation standards, leak detection and repair (LDAR) for open-ended valves or lines, compliance period for LDAR for newly affected units, exemption to notification requirement for reconstruction, disposal of carbon from control devices, the definition of capital expenditure and initial compliance clarification. We are proposing to address these issues to clarify the rule, improve implementation and update procedures, as fully detailed in section IX.

C. Costs and Benefits

The EPA has estimated emissions reductions, costs and benefits for two years of analysis: 2020 and 2025. Actions taken to comply with the proposed NSPS are anticipated to prevent significant new emissions, including 170,000 to 180,000 tons of methane, 120,000 tons of VOC and 310 to 400 tons of hazardous air pollutants (HAP) in 2020. The emission reductions are 340,000 to 400,000 tons of methane, 170,000 to 180,000 tons of VOC, and 1,900 to 2,500 tons of HAP in 2025. The methane-related monetized climate benefits are estimated to be $200 to $210 million in 2020 and $460 to $550 million in 2025 using a 3 percent discount rate (model average).[3]

In addition to the benefits of methane reductions, stakeholders and members of local communities across the country have reported to the EPA their significant concerns regarding potential adverse effects resulting from exposure to air toxics emitted from oil and natural gas operations. Importantly, this includes disadvantaged populations.

The measures proposed in this action achieve methane and VOC reductions through direct regulation. The hazardous air pollutant (HAP) reductions from these proposed standards will be meaningful in local communities. In addition, reduction of VOC emissions will be very beneficial in areas where ozone levels approach or exceed the National Ambient Air Quality Standards for ozone. There have been measurements of increasing ozone levels in areas with concentrated oil and natural gas activity, including Wyoming and Utah. Several VOCs that commonly are emitted in the oil and natural gas source category are HAPs listed under Clean Air Act (CAA) section 112(b), including benzene, toluene, ethylbenzene and xylenes (this group is commonly referred to as ''BTEX'') and n-hexane. These pollutants and any other HAP included in the VOC emissions controlled under the NSPS, including requirements for additional sources being proposed in this action, are controlled to the same degree. The co-benefit HAP reductions for the measures being proposed are discussed in the Regulatory Impact Analysis (RIA) and in the Background Technical Support Document (TSD) which are included in the public docket for this action.

The EPA estimates the total capital cost of the proposed NSPS will be $170 to $180 million in 2020 and $280 to $330 million in 2025. The estimate of total annualized engineering costs of the proposed NSPS is $180 to $200 million in 2020 and $370 to $500 million in 2025 when using a 7 percent discount rate. When estimated revenues from additional natural gas are included, the annualized engineering costs of the proposed NSPS are estimated to be $150 to $170 million in 2020 and $320 to $420 million in 2025, assuming a wellhead natural gas price of $4/thousand cubic feet (Mcf). These compliance cost estimates include revenues from recovered natural gas as the EPA estimates that about 8 billion cubic feet in 2020 and 16 to 19 billion cubic feet in 2025 of natural gas will be recovered by implementing the NSPS.

Considering all the costs and benefits of this proposed rule, including the resources from recovered natural gas that would otherwise be vented, this rule results in a net benefit. The quantified net benefits (the difference between monetized benefits and compliance costs) are estimated to be $35 to $42 million in 2020 using a 3 percent discount rate (model average) for climate benefits.[4] The quantified net benefits are estimated to be $120 to $150 million in 2025 using a 3 percent discount rate (model average) for climate benefits. All dollar amounts are in 2012 dollars.

[3] We estimate methane benefits associated with four different values of a one ton CH_4 reduction (model average at 2.5 percent discount rate, 3 percent, and 5 percent; 95th percentile at 3 percent). For the purposes of this summary, we present the benefits associated with the model average at 3 percent discount rate, however we emphasize the importance and value of considering the full range of social cost of methane values. We provide estimates based on additional discount rates in preamble section XI and in the RIA.

[4] Figures may not sum due to rounding.

The EPA was unable to monetize all of the benefits anticipated to result from this proposal. The only benefits monetized for this rule are methane-related climate benefits. However, there would be additional benefits from reducing VOC and HAP emissions, as well as additional benefits from reducing methane emissions because methane is a precursor to global background concentrations of ozone. A detailed discussion of these unquantified benefits are discussed in section XI of this document as well as in the RIA available in the docket.

III. General Information

A. Does this reconsideration notice apply to me?

Categories and entities potentially affected by today's notice include:

TABLE 1—INDUSTRIAL SOURCE CATEGORIES AFFECTED BY THIS ACTION

Category	NAICS code [1]	Examples of regulated entities
Industry	211111	Crude Petroleum and Natural Gas Extraction.
	211112	Natural Gas Liquid Extraction.
	221210	Natural Gas Distribution.
	486110	Pipeline Distribution of Crude Oil.
	486210	Pipeline Transportation of Natural Gas.
Federal government		Not affected.
State/local/tribal government		Not affected.

[1] North American Industry Classification System.

This table is not intended to be exhaustive, but rather is meant to provide a guide for readers regarding entities likely to be affected by this action. If you have any questions regarding the applicability of this action to a particular entity, consult either the air permitting authority for the entity or your EPA regional representative as listed in 40 CFR 60.4 or 40 CFR 63.13 (General Provisions).

B. What should I consider as I prepare my comments to the EPA?

We seek comment only on the aspects of the new source performance standards for the oil and natural gas source category for the equipment, processes and activities specifically identified in this document. We are not opening for reconsideration any other provisions of the new source performance standards at this time.

Do not submit information containing CBI to the EPA through www.regulations.gov or email. Send or deliver information identified as CBI only to the following address: OAQPS Document Control Officer (C404–02), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711, Attention: Docket ID Number EPA–HQ–OAR–2010–0505. Clearly mark the part or all of the information that you claim to be CBI. For CBI information in a disk or CD–ROM that you mail to the EPA, mark the outside of the disk or CD–ROM as CBI and then identify electronically within the disk or CD–ROM the specific information that is claimed as CBI. In addition to one complete version of the comment that includes information claimed as CBI, a copy of the comment that does not contain the information claimed as CBI must be submitted for inclusion in the public docket. Information so marked will not be disclosed except in accordance with procedures set forth in 40 CFR part 2.

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

In addition to being available in the docket, electronic copies of these proposed rules will be available on the Worldwide Web through the Technology Transfer Network (TTN). Following signature, a copy of each proposed rule will be posted on the TTN's policy and guidance page for newly proposed or promulgated rules at the following address: *http://www.epa.gov/ttn/oarpg/*. The TTN provides information and technology exchange in various areas of air pollution control.

IV. Background

A. Statutory Background

Section 111 of the CAA requires the EPA Administrator to list categories of stationary sources that, in his or her judgment, cause or contribute significantly to air pollution which may reasonably be anticipated to endanger public health or welfare. The EPA must then issue ''standards of performance'' for new sources in such source categories. The EPA has the authority to define the source categories, determine the pollutants for which standards should be developed, and identify within each source category the facilities for which standards of performance would be established.

CAA Section 111(a)(1) defines ''a standard of performance'' as ''a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirement) the Administrator determines has been adequately demonstrated.'' This definition makes clear that the standard of performance must be based on controls that constitute ''the best system of emission reduction . . . adequately demonstrated''. The standard that the EPA develops, based on the BSER, is commonly a numerical emissions limit, expressed as a performance level (*e.g.*, a rate-based standard). Generally, the EPA does not prescribe a particular technological system that must be used to comply with a standard of performance. Rather, sources generally can select any measure or combination of measures that will achieve the emissions level of the standard.

Standards of performance under section 111 are issued for new, modified and reconstructed stationary sources. These standards are referred to as ''new source performance standards.'' The EPA has the authority to define the source categories, determine the pollutants for which standards should be developed, identify the facilities within each source category to be covered and set the emission level of the standards.

CAA section 111(b)(1)(B) requires the EPA to ''at least every 8 years review and, if appropriate, revise'' performance standards unless the ''Administrator determines that such review is not appropriate in light of readily available information on the efficacy'' of the standard. When conducting a review of an existing performance standard, the EPA has discretion to revise that standard to add emission limits for pollutants or emission sources not currently regulated for that source category.

B. What are the regulatory history and litigation background regarding performance standards for the oil and natural gas sector?

In 1979, the EPA published a list of source categories, including ''crude oil and natural gas production,'' for which the EPA would promulgate standards of performance under section 111(b) of the CAA. See *Priority List and Additions to the List of Categories of Stationary Sources*, 44 FR 49222 (August 21, 1979) (''1979 Priority List''). That list included, in the order of priority for promulgating standards, source categories that the EPA Administrator had determined, pursuant to section 111(b)(1)(A), contribute significantly to air pollution that may reasonably be anticipated to endanger public health or welfare. See 44 FR at 49223; see also, 49 FR 2636, 2637. In 1979, the EPA listed crude oil and natural gas production on its priority list of source categories for promulgation of NSPS (44 FR 49222, August 21, 1979).

On June 24, 1985 (50 FR 26122), the EPA promulgated an NSPS for the source category that addressed VOC emissions from leaking components at onshore natural gas processing plants (40 CFR part 60, subpart KKK). On October 1, 1985 (50 FR 40158), a second NSPS was promulgated for the source category that regulates sulfur dioxide (SO_2) emissions from natural gas processing plants (40 CFR part 60, subpart LLL). In 2012, pursuant to its authority under section 111(b)(1)(B) to review and, if appropriate, revise NSPS, the EPA published the final rule, ''Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution'' (40 CFR part 60, subpart OOOO)(''2012 NSPS''). The 2012 NSPS updated the VOC standards for equipment leaks at onshore natural gas processing plants. In addition, it established VOC standards for several oil and natural gas-related operations not covered by subpart KKK, including gas well completions, centrifugal and reciprocating compressors, natural gas-operated pneumatic controllers and storage vessels. In 2013 and 2014, the EPA made certain amendments to the 2012 NSPS in order to improve implementation of the standards (78 FR 58416 and 79 FR 79018). The 2013 amendments focused on storage vessel implementation issues; the 2014 amendments provided clarification of well completion provisions which became fully effective on January 1, 2015. The EPA received petitions for both judicial review and administrative reconsiderations for the 2012 NSPS as well as the subsequent amendments in 2013 and 2014. The litigations are stayed pending the EPA's reconsideration process.

In this rulemaking, the EPA is granting reconsideration of a number of issues raised in the administrative reconsideration petitions and, where appropriate, is proposing amendments to address such issues. These issues, which mostly address implementation, are as follows: storage vessel control device monitoring and testing provisions, initial compliance requirements in § 60.5411(c)(3)(i)(A) for a bypass device that could divert an emission stream away from a control device, recordkeeping requirements of § 60.5420(c) for repair logs for control devices failing a visible emissions test, clarification of the due date for the initial annual report under the 2012 NSPS, emergency flare exemption from routine compliance tests, LDAR for open-ended valves or lines, compliance period for LDAR for newly affected process units, exemption to notification requirement for reconstruction of most types of facilities, and disposal of carbon from control devices.

C. Events Leading to Today's Action

Several factors have led to today's proposed action. First, the EPA in 2009 found that six well-mixed GHGs—carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride—endanger both the public health and the public welfare of current and future generations by causing or contributing to climate change. Oil and gas operations are significant emitters of methane. According to Greenhouse Gas Reporting Program (GHGRP) data, oil and gas operations are the second largest emitter of GHGs in the U.S. (when considering both methane emissions and combustion-related GHG emissions at oil and gas facilities), second only than fossil-fueled electricity generation. This endangerment finding is described in more detail in section VI.

Second, on August 16, 2012, the EPA published the 2012 NSPS (77 FR 49490). The 2012 NSPS included VOC standards for a number of emission sources in the oil and natural gas source category. Based on information available at the time, the EPA also evaluated methane emissions and reductions during the 2012 NSPS rulemaking as a potential co-benefit from regulating VOC. Although information at the time indicated that methane emissions could be significant, the EPA did not take final action in the 2012 NSPS with respect to the regulation of methane; the EPA noted the impending collection of a large amount of GHG data for this industry through the GHGRP (40 CFR part 98) and expressed its intent to continue its evaluation of methane. As stated previously, the 2012 NSPS is the subject of a number of petitions for judicial review and administrative reconsideration. The litigation is currently stayed pending the EPA's reconsideration process. Regulation of methane is an issue raised in several of the administrative petitions for the EPA's reconsideration.

Third, in June 2013, President Obama issued his Climate Action Plan which, among other actions, directed the EPA and five other federal agencies to develop a comprehensive interagency strategy to reduce methane emissions. The plan recognized that methane emissions constitute a significant percentage of domestic GHG emissions, highlighted reductions in methane emissions since 1990, and outlined specific actions that could be taken to achieve additional progress. Specifically, the federal agencies were instructed to focus on ''assessing current emissions data, addressing data gaps, identifying technologies and best practices for reducing emissions and identifying existing authorities and incentive-based opportunities to reduce methane emissions.''

Fourth, as a follow-up to the 2013 Climate Action Plan, the Climate Action Plan: Strategy to Reduce Methane Emissions (the Methane Strategy) was released in March 2014. The focus on reducing methane emissions reflects the fact that methane is a potent GHG with a 100-year global warming potential (GWP) that is 28–36 times greater than that of carbon dioxide.[5] Methane has an atmospheric life of about 12 years, and because of its potency as a GHG and its atmospheric life, reducing methane emissions is an important step that can be taken to achieve a near-term beneficial impact in mitigating global climate change. The Methane Strategy instructed the EPA to release a series of white papers on several potentially significant sources of methane in the oil and natural gas sector and to solicit input from independent experts. The papers were released in April 2014.

[5] IPCC, 2013: Climate Change 2013: The Physical Science Basis. Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Stocker, T.F., D. Qin, G.-K. Plattner, M. Tignor, S.K. Allen, J. Boschung, A. Nauels, Y. Xia, V. Bex and P.M. Midgley (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, 1535 pp. Note that for purposes of inventories and reporting, GWP values from the 4th Assessment Report may be used.

They focused on technical issues, covering emissions and control technologies that reduce both VOC and methane, with particular focus on completions of hydraulically fractured oil wells, liquids unloading, leaks, pneumatic devices and compressors. The peer review process was completed on June 16, 2014. The EPA received 26 submissions of peer review comments on these papers, and more than 43,000 comments from the public. The comments received from the peer reviewers are available on EPA's oil and natural gas white paper Web site (*http://www.epa.gov/airquality/oilandgas/methane.html*). Public comments on the white papers are available in EPA's nonregulatory docket at *www.regulations.gov,* docket ID # EPA–HQ–OAR–2014–0557. The Methane Strategy also instructed the EPA to complete any new oil and natural gas regulations pertaining to the sources addressed in the white papers by the end of 2016.

Finally, following the Climate Action Plan and Methane Strategy, in January 2015, the Administration announced a new goal to cut methane emissions from the oil and gas sector (by 40–45 percent from 2012 levels by 2025) and steps to put the U.S. on a path to achieve this ambitious goal. These actions encompass both commonsense standards and cooperative engagement with states, tribes and industry. Building on prior actions by the Administration, and leadership in states and industry, the announcement laid out a plan for EPA to address, and if appropriate, propose and set commonsense standards for methane and ozone forming emissions from new and modified sources and issue Control Technique Guidelines (CTGs) to assist states in reducing ozone-forming pollutants from existing oil and gas systems in areas that do not meet the health-based standard for ozone.

Building on the 2012 NSPS, the EPA intends to encourage corporate-wide efforts to achieve emission reductions through transparent and verifiable voluntary action that would obviate the burden associated with NSPS applicability. Throughout this proposal, we solicit comment on specific approaches that could provide incentive for owners and operators to design and implement programs to reduce fugitive emissions at their facilities.

V. Why is the EPA Proposing to Establish Methane Standards in the Oil and Natural Gas NSPS?

In a petition for reconsideration of the 2012 NSPS, the petitioners urged that ''EPA must reconsider its failure adopt standards for the methane pollution released by the oil and gas sector.'' [6] Upon reconsidering the issue, and on the basis of the wealth of additional information now available to us, the EPA is proposing to establish methane standards for facilities throughout the oil and natural gas source category.

The EPA has discretion under CAA section 111(b) to determine which pollutants emitted from a listed source category warrant regulation.[7] In making such determination, we have generally considered a number of factors to help inform our decision (We discuss considerations specific to individual emission source types in section VIII as part of the BSER analyses and rationale for regulating the sources). These factors include the amount such pollutant is being emitted from the source category, the availability of technically feasible control options and the costs of such control options. As we previously explained, ''we have historically declined to propose standards for a pollutant where it is emitting (sic) in low amounts or where we determined that a [control analysis] would result in no control'' device being used. 75 FR 54970, 54997 (Sep. 9, 2010). Our consideration of these factors are provided below and in more detail in sections VI and VIII.

The oil and natural gas industry is one of the largest emitters of methane, a GHG with a global warming potential more than 25 times greater than that of carbon dioxide. During the 2012 oil and natural gas NSPS rulemaking, while we had considerable amount of data and understanding on VOC emissions from the oil and natural gas industry and the available control options, data on methane emissions were just emerging. In light of the rapid expansion of this industry and the growing concern with the associated emissions, the EPA proceeded to establish a number of VOC standards in the 2012 NSPS but indicated in that rulemaking an intent to revisit methane at a later date when additional information was available from the GHGRP. We have since received and evaluated such data, which confirm that the oil and natural gas industry is one of the largest emitters of methane. As discussed in section VI, the current methane emissions from this industry contribute substantially to nationwide GHG emissions. These emissions are expected to increase as a result of the rapid growth of this industry. While the VOC standards in the 2012 NSPS also reduce methane emissions, in light of the current and projected future methane emissions from the oil and natural gas industry, reducing methane emissions from this source category cannot be treated simply as an incidental benefit to VOC reduction; rather, it is something that should be directly addressed through standards for methane under section 111(b) based on direct evaluation of the extent and impact of methane emissions from this source category and the best system for their reduction. Such standards, which would be reviewed and, if appropriate, revised at least every eight years, would achieve meaningful methane reductions and, as such, would be an important step towards mitigating the impact of GHG emissions on climate change. In addition, while many of the currently regulated emission sources are equipment used throughout the oil and natural gas industry (*e.g.*, pneumatic controllers, compressors) and emit both VOC and methane, the current VOC standards apply only to a subset of these equipment based on VOC-only evaluation. However, as shown in section VIII, there are cost-effective controls that can simultaneously reduce both methane and VOC emissions from these equipment across the industry, which in some instances would not occur were we to focus solely on VOC reductions. Revising the NSPS to establish both methane and VOC standards for all such equipment across the industry would also promote consistency by providing the same regulatory regime for these equipment throughout the oil and natural gas source category, thereby facilitating implementation and enforcement.[8]

As mentioned above, we also we consider whether there are technically feasible control options that can be applied nationally to sources to mitigate emissions of a pollutant and whether the costs of such controls are reasonable. As discussed in detail in section VIII, we have identified

[6] Sierra Club *et al.*, Petition for Reconsideration, In the Matter of: Final Rule Published at 77 FR 49490 (Aug. 16, 2012), titled ''Oil and Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews; Final Rule,'' Docket No. EPA–HQ–OAR–2010–0505, RIN 2060–AP76 (2012).

[7] See 42 U.S.C. § 7411(b)

[8] The EPA often revises standards even where the revision will not lead to any additional reductions of a pollutant because another standard regulates a different pollutant using the same control equipment. For example, in 2014, the EPA revised the Kraft Pulp Mill NSPS in Part 60 Subpart BB (published at 70 FR 18952 (April 4, 2014) to align the NSPS standards with the NESHAP standards for those sources in Part 63 Subpart S. Although no previously unregulated sources were added to the Kraft Pulp Mill NSPS, several emission limits were adjusted downward. The revised NSPS did not achieve additional reductions beyond those achieved by the NESHAP, but eased compliance burden for the sources.

technically feasible controls that can be applied nationally to reduce methane emissions and thus GHG emissions from the oil and natural gas source category. We consider whether the costs (*e.g.*, capital costs, operating costs) are reasonable considering the emission reductions achieved through application of the controls that would be required by the proposed rule. As discussed in detail in section VIII, for the oil and natural gas source category, the available controls for reducing methane emissions simultaneously control VOC emissions and vice versa. Accordingly, the available controls are the same for reducing methane and VOC from the individual oil and natural gas emission sources. For a detailed discussion on how we evaluated control costs and our cost analysis for individual emission sources, please see section VIII. As shown in that section, there are cost-effective controls for reducing methane emissions from the oil and natural gas source category.

Based on our consideration of the three factors, the EPA is proposing to revise the NSPS to regulate directly GHG emissions in addition to VOC emissions across the oil and natural gas source category. The proposed standards include adding methane standards to certain sources currently regulated for VOC, as well as methane and VOC standards for additional emission sources. Specifically,

- Well completions: We are proposing to revise the current NSPS to regulate both methane and VOC emissions from well completions of all hydraulically fractured wells (*i.e.*, gas wells and oil wells);
- Fugitive emissions: We are proposing standards to reduce methane and VOC emissions from fugitive emission components at well sites and compressor stations;
- Pneumatic pumps: We are proposing methane and VOC standards;
- Pneumatic controllers, centrifugal compressors, and reciprocating compressors (industry-wide, except for well site compressors, of which only a subset of those equipment are regulated currently): We are proposing to establish methane and VOC standards across the industry by adding methane standards to those currently subject to VOC standard and VOC and methane standards for all the others.
- Equipment leaks at natural gas processing plants: We are proposing to add methane standards.

For a detailed description of the proposed standards, please see section VII. For the BSER analyses that serve as the bases for the proposed standards, please see section VIII.

VI. The Oil and Natural Gas Source Category Listing Under CAA Section 111(b)(1)(A)

Section 111(b)(1)(A) of the CAA, which Congress enacted as part of the 1970 CAA Amendments, requires the EPA to promulgate a list of categories of stationary sources that the Administrator, in his or her judgment, finds ''causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare.'' In 1979, the EPA published a list of source categories, including ''crude oil and natural gas production,'' for which the EPA would promulgate standards of performance under section 111(b) of the CAA. *Priority List and Additions to the List of Categories of Stationary Sources,* 44 FR 49222 (August 21, 1979) (''1979 Priority List''). That list included, in the order of priority for promulgating standards, source categories that the EPA Administrator had determined, pursuant to section 111(b)(1)(A), to contribute significantly to air pollution that may reasonably be anticipated to endanger public health or welfare. See 44 FR 49222; see also, 49 FR 2636, 2637.

As mentioned above, one of the source categories listed in that 1979 rulemaking related to the oil and natural gas industry. The EPA interprets the listing that resulted from that rulemaking as generally covering the oil and natural gas industry. Specifically, with respect to the natural gas industry, it includes production, processing, transmission, and storage. The EPA believes that the intent of the 1979 listing was to broadly cover the natural gas industry.[9] This intent was evident in the EPA's analysis at the time of listing.[10] For example, the priority list analysis indicated that the EPA evaluated emissions beyond the natural gas production segment to include emissions from natural gas processing plants. The analysis also showed that the EPA evaluated equipment, such as stationary pipeline compressor engines, that are used in various segments of the natural gas industry. The EPA's interpretation of the 1979 listing is further supported by the Agency's pronouncements during the NSPS rulemaking that followed the listing. Specifically, in its description of this listed source category in the 1984 preamble to the proposed NSPS for equipment leaks at natural gas processing plants, the EPA described the major emission points of this source category to include process, storage and equipment leaks; these emissions can be found throughout the various segments of the natural gas industry. 49 FR at 2637. There are also good reasons for treating various segments of the natural gas industry as one source category. Operations at production, processing, transmission and storage facilities are a sequence of functions that are interrelated and necessary for getting the recovered gas ready for distribution.[11] Because they are interrelated, segments that follow others are faced with increases in throughput caused by growth in throughput of the segments preceding (*i.e.,* feeding) them. For example, the relatively recent substantial increases in natural gas production brought about by hydraulic fracturing and horizontal drilling result in increases in the amount of natural gas needing to be processed and moved to market or stored. These increases in production and throughput can cause increases in emissions across the entire natural gas industry. We also note that some equipment (*e.g.,* storage vessels, compressors) are used across the oil and natural gas industry, which further supports considering the industry as one source category. For the reasons stated above, the EPA interprets the 1979 listing broadly to include the various segments of the natural gas industry (production, processing, transmission, and storage).

Since the 1979 listing, EPA has promulgated performance standards to regulate SO_2 emissions from natural gas processing and VOC emissions from the oil and natural gas industry. In this action, the EPA is proposing to further regulate VOC emissions as well as proposing performance standards for methane emissions from this industry. With respect to the latter, the EPA identifies the air pollutant that it proposes to regulate as the pollutant GHGs (which consist of the six well-mixed gases, consistent with other actions the EPA has taken under the

[9] The process of producing natural gas for distribution involves operations in the various segments of the natural gas industry described above. In contrast, oil production involves drilling/extracting oil, which is immediately followed by distribution offsite to be made into different products.

[10] See *Standards of Performance for New Stationary Sources,* 43 FR 38872, August 31, 1978, and *Priority List and Additions to the List of Categories of Stationary Sources,* 44 FR 49222, August 21, 1979.

[11] The crude oil production segment of the source category, which includes the well and extends to the point of custody transfer to the crude oil transmission pipeline, is more limited in scope than the segments of the natural gas value chain included in the source category. However, increases in production at the well and/or increases in the number of wells coming on line, in turn increase throughput and resultant emissions, similarly to the natural gas segments in the source category.

CAA), although only methane will be reduced directly by the proposed standards.

As mentioned above, in the 1979 category listing, section 111(b)(1)(A) does not require another determination as a prerequisite for regulating a particular pollutant. Rather, once the EPA has determined that the source category causes, or contributes significantly to, air pollution that may reasonably be anticipated to endanger public health or welfare, and has listed the source category on that basis, the EPA interprets section 111(b)(1)(A) to provide authority to establish a standard for performance for any pollutant emitted by that source category as long as the EPA has a rational basis for setting a standard for the pollutant.[12] The EPA believes that the information included below in this section provides a rational basis for the methane standards it is proposing in this action.

First, because the EPA is not listing a new source category in this rule, the EPA is not required to make a new endangerment finding with regard to oil and natural gas source category in order to establish standards of performance for the methane from those sources. Under the plain language of CAA section 111(b)(1)(A), an endangerment finding is required only to list a source category. Further, though the endangerment finding is based on determinations as to the health or welfare impacts of the pollution to which the source category's pollutants contribute, and as to the significance of the amount of such contribution, the statute is clear that the endangerment finding is made with respect to the source category; section 111(b)(1)(A) does not provide that an endangerment finding is made as to specific pollutants. This contrasts with other CAA provisions that do require the EPA to make endangerment findings for each particular pollutant that the EPA regulates under those provisions. E.g., CAA sections 202(a)(1), 211(c)(1), 231(a)(2)(A). See *American Electric Power* v. *Connecticut,* 131 S. Ct. 2527, 2539 (2011) (''the Clean Air Act directs EPA to establish emissions standards for categories of stationary sources that, 'in [the Administrator's] judgment,' 'caus[e], or contribut[e] significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare.' § 7411(b)(1)(A).'') (emphasis added).

Second, once a source category is listed, the CAA does not specify what pollutants should be the subject of standards from that source category. The statute, in section 111(b)(1)(B), simply directs the EPA to propose and then promulgate regulations ''establishing Federal standards of performance for new sources within such category.'' In the absence of specific direction or enumerated criteria in the statute concerning what pollutants from a given source category should be the subject of standard, it is appropriate for EPA to exercise its authority to adopt a reasonable interpretation of this provision. *Chevron U.S.A. Inc.* v. *NRDC,* 467 U.S. 837, 843–44 (1984).

The EPA has previously interpreted this provision as granting it the discretion to determine which pollutants should be regulated. See Standards of Performance for Petroleum Refineries, 73 FR 35838, 35858 (col. 3) (June 24, 2008) (concluding the statute provides ''the Administrator with significant flexibility in determining which pollutants are appropriate for regulation under section 111(b)(1)(B)'' and citing cases). Further, in directing the Administrator to propose and promulgate regulations under section 111(b)(1)(B), Congress provided that the Administrator should take comment and then finalize the standards with such modifications ''as he deems appropriate.'' The DC Circuit has considered similar statutory phrasing from CAA section 231(a)(3) and concluded that ''[t]his delegation of authority is both explicit and extraordinarily broad.'' *National Assoc. of Clean Air Agencies* v. *EPA,* 489 F.3d 1221, 1229 (D.C. Cir. 2007).

In exercising its discretion with respect to which pollutants are appropriate for regulation under section 111(b)(1)(B), the EPA has in the past provided a rational basis for its decisions. See *National Lime Assoc.* v. *EPA,* 627 F.2d 416, 426 & n.27 (D.C. Cir. 1980) (court discussed, but did not review, the EPA's reasons for not promulgating standards for NO_X, SO_2 and CO from lime plants''); Standards of Performance for Petroleum Refineries, 73 FR at 35859–60 (June 24, 2008) (providing reasons why the EPA was not promulgating GHG standards for petroleum refineries as part of that rule). Though these previous examples involved the EPA providing a rational basis for not setting standards for a given pollutant, a similar approach is appropriate where the EPA determines that it should set a standard for an additional pollutant for a source category that was previously listed and regulated for other pollutants.

While the EPA believes that the 1979 listing of this source category provides sufficient authority for this action, to the extent that there is any ambiguity in the prior listing, the information provided here should be considered to constitute the requisite conclusions related to the category listing. Were EPA to formally seek to revise the category listing to broadly include the oil and natural gas industry (i.e., production, processing, transmission, and storage)[13], we believe this information discussed here fully suffices to support it as a source category that, in the Administrator's judgment, contributes significantly to air pollution which may reasonably be anticipated to endanger public health or welfare. Furthermore, for the reason stated below, EPA's previous determination under section 111(b)(1)(A) is sufficient to support the proposed revision to the category listing as well as the proposed standards in this action. During the 1979 listing, EPA had determined that, at least a part of the oil and natural gas industry contributes significantly to air pollution which may reasonably be anticipated to endanger public health or welfare. Such health and welfare impacts could only increase when considering the broader industry (assuming it had not already been considered in the 1979 listing). To further support the conclusion related to this category listing, EPA has included below in this section information and analyses regarding the public health and welfare impacts from GHG, VOC and SO_2 emissions, three of the primary pollutants emitted from the oil and natural gas industry, and the estimated emissions of these pollutants from the oil and natural gas source category. It is evident from this information and analyses that the oil and natural gas source category contributes significantly to air pollution which may reasonably be anticipated to endanger public health or welfare.

Provided below are the supporting information and analyses. Specifically, section VI.A describes the public health and welfare impacts from GHG, VOC and SO_2. Section VI.B analyzes the emission contribution of these three pollutants by the oil and natural gas industry.

A. Impacts of GHG, VOC and SO_2 Emissions on Public Health and Welfare

The oil and natural gas industry emits a wide range of pollutants, including GHGs (such as methane and CO_2), VOC, SO_2, NO_X, H_2S, CS_2 and COS. See 49 FR 2636, at 2637 (Jan 20, 1984). Although all of these pollutants have significant impacts on public health and welfare, an analysis of every one of these

[12] See additional discussion at 79 FR 1430, 1452 (Jan 8, 2014).

[13] For the oil industry, the listing includes production, as explained above in footnote 10.

pollutants is not necessary for the Administrator to make a determination under section 111(b)(1)(A); as shown below, the EPA's analysis of GHG, VOC, and SO_2, three of the primary emissions from the oil and natural gas source category, alone are sufficient for the Administrator to determine under section 111(b)(1)(A) that the oil and natural gas source category contributes significantly to air pollution which may reasonably be anticipated to endanger public health and welfare.[14]

1. Climate Change Impacts from GHG Emissions

In 2009, based on a large body of robust and compelling scientific evidence, the EPA Administrator issued the Endangerment Finding under CAA section 202(a)(1).[15] In the Endangerment Finding, the Administrator found that the current, elevated concentrations of GHGs in the atmosphere—already at levels unprecedented in human history—may reasonably be anticipated to endanger public health and welfare of current and future generations in the United States. We summarize these adverse effects on public health and welfare briefly here.

a. Public Health Impacts Detailed in the 2009 Endangerment Finding

Climate change caused by human emissions of GHGs threatens the health of Americans in multiple ways. By raising average temperatures, climate change increases the likelihood of heat waves, which are associated with increased deaths and illnesses. While climate change also increases the likelihood of reductions in cold-related mortality, evidence indicates that the increases in heat mortality will be larger than the decreases in cold mortality in the United States. Compared to a future without climate change, climate change is expected to increase ozone pollution over broad areas of the U.S., especially on the highest ozone days and in the largest metropolitan areas with the worst ozone problems, and thereby increase the risk of morbidity and mortality. Climate change is also expected to cause more intense hurricanes and more frequent and intense storms and heavy precipitation, with impacts on other areas of public health, such as the potential for increased deaths, injuries, infectious and waterborne diseases, and stress-related disorders. Children, the elderly, and the poor are among the most vulnerable to these climate-related health effects.

b. Public Welfare Impacts Detailed in the 2009 Endangerment Finding

Climate change impacts touch nearly every aspect of public welfare. Among the multiple threats caused by human emissions of GHGs, climate changes are expected to place large areas of the country at serious risk of reduced water supplies, increased water pollution, and increased occurrence of extreme events such as floods and droughts. Coastal areas are expected to face a multitude of increased risks, particularly from rising sea level and increases in the severity of storms. These communities face storm and flooding damage to property, or even loss of land due to inundation, erosion, wetland submergence and habitat loss.

Impacts of climate change on public welfare also include threats to social and ecosystem services. Climate change is expected to result in an increase in peak electricity demand, Extreme weather from climate change threatens energy, transportation, and water resource infrastructure. Climate change may also exacerbate ongoing environmental pressures in certain settlements, particularly in Alaskan indigenous communities, and is very likely to fundamentally rearrange U.S. ecosystems over the 21st century. Though some benefits may balance adverse effects on agriculture and forestry in the next few decades, the body of evidence points towards increasing risks of net adverse impacts on U.S. food production, agriculture and forest productivity as temperature continues to rise. These impacts are global and may exacerbate problems outside the U.S. that raise humanitarian, trade, and national security issues for the U.S.

c. New Scientific Assessments and Observations

Since the administrative record concerning the Endangerment Finding closed following the EPA's 2010 Reconsideration Denial, the climate has continued to change, with new records being set for a number of climate indicators such as global average surface temperatures, Arctic sea ice retreat, CO_2 concentrations, and sea level rise. Additionally, a number of major scientific assessments have been released that improve understanding of the climate system and strengthen the case that GHGs endanger public health and welfare both for current and future generations. These assessments, from the Intergovernmental Panel on Climate Change (IPCC), the U.S. Global Change Research Program (USGCRP), and the National Research Council of the National Academies (NRC), include: IPCC's 2012 *Special Report on Managing the Risks of Extreme Events and Disasters to Advance Climate Change Adaptation* (SREX) and the 2013–2014 Fifth Assessment Report (AR5), USGCRP's 2014 National Climate Assessment, Climate Change Impacts in the United States (NCA3), and the NRC's 2010 *Ocean Acidification: A National Strategy to Meet the Challenges of a Changing Ocean* (Ocean Acidification), 2011 *Report on Climate Stabilization Targets: Emissions, Concentrations, and Impacts over Decades to Millennia* (Climate Stabilization Targets), 2011 *National Security Implications for U.S. Naval Forces* (National Security Implications), 2011 *Understanding Earth's Deep Past: Lessons for Our Climate Future* (Understanding Earth's Deep Past), 2012 *Sea Level Rise for the Coasts of California, Oregon, and Washington: Past, Present, and Future,* 2012 *Climate and Social Stress: Implications for Security Analysis* (Climate and Social Stress), and 2013 *Abrupt Impacts of Climate Change* (Abrupt Impacts) assessments.

The EPA has carefully reviewed these recent assessments in keeping with the same approach outlined in Section VIII.A. of the 2009 Endangerment Finding, which was to rely primarily upon the major assessments by the USGCRP, IPCC, and the NRC to provide the technical and scientific information to inform the Administrator's judgment regarding the question of whether GHGs endanger public health and welfare. These assessments addressed the scientific issues that the EPA was required to examine were comprehensive in their coverage of the GHG and climate change issues, and underwent rigorous and exacting peer review by the expert community, as well as rigorous levels of U.S. government review.

The findings of the recent scientific assessments confirm and strengthen the conclusion that GHGs endanger public health, now and in the future. The NCA3 indicates that human health in the United States will be impacted by ''increased extreme weather events, wildfire, decreased air quality, threats to mental health, and illnesses transmitted by food, water, and disease-carriers such as mosquitoes and ticks.'' The most recent assessments now have greater

[14] We note that EPA's focus on GHG (in particular methane), VOC and SO_2 in these analyses, does not in any way limit the EPA's authority to promulgate standards that would apply to other pollutants emitted from the oil and natural gas source category, if the EPA determines that such action is appropriate.

[15] ''Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act,'' 74 FR 66496 (Dec. 15, 2009) (''Endangerment Finding'').

confidence that climate change will influence production of pollen that exacerbates asthma and other allergic respiratory diseases such as allergic rhinitis, as well as effects on conjunctivitis and dermatitis. Both the NCA3 and the IPCC AR5 found that increasing temperature has lengthened the allergenic pollen season for ragweed, and that increased CO_2 by itself can elevate production of plant-based allergens.

The NCA3 also finds that climate change, in addition to chronic stresses such as extreme poverty, is negatively affecting indigenous peoples' health in the United States through impacts such as reduced access to traditional foods, decreased water quality, and increasing exposure to health and safety hazards. The IPCC AR5 finds that climate change-induced warming in the Arctic and resultant changes in environment (*e.g.,* permafrost thaw, effects on traditional food sources) have significant impacts, observed now and projected, on the health and well-being of Arctic residents, especially indigenous peoples. Small, remote, predominantly-indigenous communities are especially vulnerable given their ''strong dependence on the environment for food, culture, and way of life; their political and economic marginalization; existing social, health, and poverty disparities; as well as their frequent close proximity to exposed locations along ocean, lake, or river shorelines.'' [16] In addition, increasing temperatures and loss of Arctic sea ice increases the risk of drowning for those engaged in traditional hunting and fishing.

The NCA3 concludes that children's unique physiology and developing bodies contribute to making them particularly vulnerable to climate change. Impacts on children are expected from heat waves, air pollution, infectious and waterborne illnesses, and mental health effects resulting from extreme weather events. The IPCC AR5 indicates that children are among those especially susceptible to most allergic diseases, as well as health effects associated with heat waves, storms, and floods. The IPCC finds that additional health concerns may arise in low income households, especially those with children, if climate change reduces food availability and increases prices, leading to food insecurity within households.

Both the NCA3 and IPCC AR5 conclude that climate change will increase health risks facing the elderly. Older people are at much higher risk of mortality during extreme heat events. Pre-existing health conditions also make older adults susceptible to cardiac and respiratory impacts of air pollution and to more severe consequences from infectious and waterborne diseases. Limited mobility among older adults can also increase health risks associated with extreme weather and floods.

The new assessments also confirm and strengthen the conclusion that GHGs endanger public welfare, and emphasize the urgency of reducing GHG emissions due to their projections that show GHG concentrations climbing to ever-increasing levels in the absence of mitigation. The NRC assessment Understanding Earth's Deep Past projected that, without a reduction in emissions, CO_2 concentrations by the end of the century would increase to levels that the Earth has not experienced for more than 30 million years.[17] In fact, that assessment stated that ''the magnitude and rate of the present GHG increase place the climate system in what could be one of the most severe increases in radiative forcing of the global climate system in Earth history.'' [18] Because of these unprecedented changes, several assessments state that we may be approaching critical, poorly understood thresholds: As stated in the NRC assessment Understanding Earth's Deep Past, ''As Earth continues to warm, it may be approaching a critical climate threshold beyond which rapid and potentially permanent—at least on a human timescale—changes not anticipated by climate models tuned to modern conditions may occur.'' The NRC Abrupt Impacts report analyzed abrupt climate change in the physical climate system and abrupt impacts of ongoing changes that, when thresholds are crossed, can cause abrupt impacts for society and ecosystems. The report considered destabilization of the West Antarctic Ice Sheet (which could cause 3–4 m of potential sea level rise) as an abrupt climate impact with unknown but probably low probability of occurring this century. The report categorized a decrease in ocean oxygen content (with attendant threats to aerobic marine life); increase in intensity, frequency, and duration of heat waves; and increase in frequency and intensity of extreme precipitation events (droughts, floods, hurricanes, and major storms) as climate impacts with moderate risk of an abrupt change within this century. The NRC *Abrupt Impacts* report also analyzed the threat of rapid state changes in ecosystems and species extinctions as examples of an irreversible impact that is expected to be exacerbated by climate change. Species at most risk include those whose migration potential is limited, whether because they live on mountaintops or fragmented habitats with barriers to movement, or because climatic conditions are changing more rapidly than the species can move or adapt. While the NRC determined that it is not presently possible to place exact probabilities on the added contribution of climate change to extinction, they did find that there was substantial risk that impacts from climate change could, within a few decades, drop the populations in many species below sustainable levels thereby committing the species to extinction. Species within tropical and subtropical rainforests such as the Amazon and species living in coral reef ecosystems were identified by the NRC as being particularly vulnerable to extinction over the next 30 to 80 years, as were species in high latitude and high elevation regions. Moreover, due to the time lags inherent in the Earth's climate, the NRC Climate Stabilization Targets assessment notes that the full warming from increased GHG concentrations will not be fully realized for several centuries, underscoring that emission activities today carry with them climate commitments far into the future.

Future temperature changes will depend on what emission path the world follows. In its high emission scenario, the IPCC AR5 projects that global temperatures by the end of the century will likely be 2.6 °C to 4.8 °C (4.7 to 8.6 °F) warmer than today. Temperatures on land and in northern latitudes will likely warm even faster than the global average. However, according to the NCA3, significant reductions in emissions would lead to noticeably less future warming beyond mid-century, and therefore less impact to public health and welfare.

While rainfall may only see small globally and annually averaged changes, there are expected to be substantial shifts in where and when that precipitation falls. According to the NCA3, regions closer to the poles will see more precipitation, while the dry subtropics are expected to expand (colloquially, this has been summarized

[16] IPCC, 2014: *Climate Change 2014: Impacts, Adaptation, and Vulnerability. Part B: Regional Aspects.* Contribution of Working Group II to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Barros, V.R., C.B. Field, D.J. Dokken, M.D. Mastrandrea, K.J. Mach, T.E. Bilir, M. Chatterjee, K.L. Ebi, Y.O. Estrada, R.C. Genova, B. Girma, E.S. Kissel, A.N. Levy, S. MacCracken, P.R. Mastrandrea, and L.L. White (eds.)]. Cambridge University Press, Cambridge, p. 1581.

[17] National Research Council, Understanding Earth's Deep Past, p. 1.

[18] *Id.*, p. 138.

as wet areas getting wetter and dry regions getting drier). In particular, the NCA3 notes that the western U.S., and especially the Southwest, is expected to become drier. This projection is consistent with the recent observed drought trend in the West. At the time of publication of the NCA, even before the last 2 years of extreme drought in California, tree ring data were already indicating that the region might be experiencing its driest period in 800 years. Similarly, the NCA3 projects that heavy downpours are expected to increase in many regions, with precipitation events in general becoming less frequent but more intense. This trend has already been observed in regions such as the Midwest, Northeast, and upper Great Plains. Meanwhile, the NRC Climate Stabilization Targets assessment found that the area burned by wildfire is expected to grow by 2 to 4 times for 1 °C (1.8 °F) of warming. For 3 °C of warming, the assessment found that 9 out of 10 summers would be warmer than all but the 5 percent of warmest summers today, leading to increased frequency, duration, and intensity of heat waves. Extrapolations by the NCA also indicate that Arctic sea ice in summer may essentially disappear by mid-century. Retreating snow and ice, and emissions of carbon dioxide and methane released from thawing permafrost, will also amplify future warming.

Since the 2009 Endangerment Finding, the USGCRP NCA3, and multiple NRC assessments have projected future rates of sea level rise that are 40 percent larger to more than twice as large as the previous estimates from the 2007 IPCC 4th Assessment Report due in part to improved understanding of the future rate of melt of the Antarctic and Greenland ice sheets. The NRC Sea Level Rise assessment projects a global sea level rise of 0.5 to 1.4 meters (1.6 to 4.6 feet) by 2100, the NRC National Security Implications assessment suggests that ''the Department of the Navy should expect roughly 0.4 to 2 meters (1.3 to 6.6 feet) global average sea-level rise by 2100,'' [19] and the NRC Climate Stabilization Targets assessment states that an increase of 3 °C will lead to a sea level rise of 0.5 to 1 meter (1.6 to 3.3 feet) by 2100. These assessments continue to recognize that there is uncertainty inherent in accounting for ice sheet processes. Additionally, local sea level rise can differ from the global total depending on various factors: The east coast of the U.S. in particular is expected to see higher rates of sea level rise than the global average. For comparison, the NCA3 states that ''five million Americans and hundreds of billions of dollars of property are located in areas that are less than four feet above the local high-tide level,'' and the NCA3 finds that ''[c]oastal infrastructure, including roads, rail lines, energy infrastructure, airports, port facilities, and military bases, are increasingly at risk from sea level rise and damaging storm surges.'' [20] Also, because of the inertia of the oceans, sea level rise will continue for centuries after GHG concentrations have stabilized (though more slowly than it would have otherwise). Additionally, there is a threshold temperature above which the Greenland ice sheet will be committed to inevitable melting: According to the NCA, some recent research has suggested that even present day carbon dioxide levels could be sufficient to exceed that threshold.

In general, climate change impacts are expected to be unevenly distributed across different regions of the United States and have a greater impact on certain populations, such as indigenous peoples and the poor. The NCA3 finds climate change impacts such as the rapid pace of temperature rise, coastal erosion and inundation related to sea level rise and storms, ice and snow melt, and permafrost thaw are affecting indigenous people in the United States. Particularly in Alaska, critical infrastructure and traditional livelihoods are threatened by climate change and, ''[i]n parts of Alaska, Louisiana, the Pacific Islands, and other coastal locations, climate change impacts (through erosion and inundation) are so severe that some communities are already relocating from historical homelands to which their traditions and cultural identities are tied.'' [21] The IPCC AR5 notes, ''Climate-related hazards exacerbate other stressors, often with negative outcomes for livelihoods, especially for people living in poverty (high confidence). Climate-related hazards affect poor people's lives directly through impacts on livelihoods, reductions in crop yields, or destruction of homes and indirectly through, for example, increased food prices and food insecurity.'' [22]

Events outside the United States, as also pointed out in the 2009 Endangerment Finding, will also have relevant consequences. The NRC Climate and Social Stress assessment concluded that it is prudent to expect that some climate events ''will produce consequences that exceed the capacity of the affected societies or global systems to manage and that have global security implications serious enough to compel international response.'' The NRC National Security Implications assessment recommends preparing for increased needs for humanitarian aid; responding to the effects of climate change in geopolitical hotspots, including possible mass migrations; and addressing changing security needs in the Arctic as sea ice retreats.

In addition to future impacts, the NCA3 emphasizes that climate change driven by human emissions of GHGs is already happening now and it is happening in the United States. According to the IPCC AR5 and the NCA3, there are a number of climate-related changes that have been observed recently, and these changes are projected to accelerate in the future. The planet warmed about 0.85 °C (1.5 °F) from 1880 to 2012. It is extremely likely (>95% probability) that human influence was the dominant cause of the observed warming since the mid-20th century, and likely (>66% probability) that human influence has more than doubled the probability of occurrence of heat waves in some locations. In the Northern Hemisphere, the last 30 years were likely the warmest 30 year period of the last 1400 years. U.S. average temperatures have similarly increased by 1.3 to 1.9 degrees F since 1895, with most of that increase occurring since 1970. Global sea levels rose 0.19 m (7.5 inches) from 1901 to 2010. Contributing to this rise was the warming of the oceans and melting of land ice. It is likely that 275 gigatons per year of ice melted from land glaciers (not including ice sheets) since 1993, and that the rate of loss of ice from the Greenland and Antarctic ice sheets increased substantially in recent years, to 215 gigatons per year and 147 gigatons per year respectively since 2002. For

[19] NRC, 2011: *National Security Implications of Climate Change for U.S. Naval Forces.* The National Academies Press, p. 28.

[20] Melillo, Jerry M., Terese (T.C.) Richmond, and Gary W. Yohe, Eds., 2014: *Climate Change Impacts in the United States: The Third National Climate Assessment.* U.S. Global Change Research Program, p. 9.

[21] Melillo, Jerry M., Terese (T.C.) Richmond, and Gary W. Yohe, Eds., 2014: *Climate Change Impacts in the United States: The Third National Climate Assessment.* U.S. Global Change Research Program, p. 17.

[22] IPCC, 2014: *Climate Change 2014: Impacts, Adaptation, and Vulnerability. Part A: Global and Sectoral Aspects.* Contribution of Working Group II to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Field, C.B., V.R. Barros, D.J. Dokken, K.J. Mach, M.D. Mastrandrea, T.E. Bilir, M. Chatterjee, K.L. Ebi, Y.O. Estrada, R.C. Genova, B. Girma, E.S. Kissel, A.N. Levy, S. MacCracken, P.R. Mastrandrea, and L.L. White (eds.)]. Cambridge University Press, p. 796.

context, 360 gigatons of ice melt is sufficient to cause global sea levels to rise 1 millimeter (mm). Annual mean Arctic sea ice has been declining at 3.5 to 4.1 percent per decade, and Northern Hemisphere snow cover extent has decreased at about 1.6 percent per decade for March and 11.7 percent per decade for June. Permafrost temperatures have increased in most regions since the 1980s, by up to 3 °C (5.4 °F) in parts of Northern Alaska. Winter storm frequency and intensity have both increased in the Northern Hemisphere. The NCA3 states that the increases in the severity or frequency of some types of extreme weather and climate events in recent decades can affect energy production and delivery, causing supply disruptions, and compromise other essential infrastructure such as water and transportation systems.

In addition to the changes documented in the assessment literature, there have been other climate milestones of note. According to the IPCC, methane concentrations in 2011 were about 1803 parts per billion, 150 percent higher than concentrations were in 1750. After a few years of nearly stable concentrations from 1999 to 2006, methane concentrations have resumed increasing at about 5 parts per billion per year. Concentrations today are likely higher than they have been for at least the past 800,000 years. Arctic sea ice has continued to decline, with September of 2012 marking a new record low in terms of Arctic sea ice extent, 40 percent below the 1979–2000 median. Sea level has continued to rise at a rate of 3.2 mm per year (1.3 inches/decade) since satellite observations started in 1993, more than twice the average rate of rise in the 20th century prior to 1993.[23] And 2014 was the warmest year globally in the modern global surface temperature record, going back to 1880; this now means 19 of the 20 warmest years have occurred in the past 20 years, and except for 1998, the ten warmest years on record have occurred since 2002.[24] The first months of 2015 have also been some of the warmest on record.

These assessments and observed changes make it clear that reducing emissions of GHGs across the globe is necessary in order to avoid the worst impacts of climate change, and underscore the urgency of reducing emissions now. The NRC Committee on America's Climate Choices listed a number of reasons ''why it is imprudent to delay actions that at least begin the process of substantially reducing emissions.'' [25] For example:

- The faster emissions are reduced, the lower the risks posed by climate change. Delays in reducing emissions could commit the planet to a wide range of adverse impacts, especially if the sensitivity of the climate to GHGs is on the higher end of the estimated range.
- Waiting for unacceptable impacts to occur before taking action is imprudent because the effects of GHG emissions do not fully manifest themselves for decades and, once manifest, many of these changes will persist for hundreds or even thousands of years.
- In the committee's judgment, the risks associated with doing business as usual are a much greater concern than the risks associated with engaging in strong response efforts.

Methane is also a precursor to ground-level ozone, a health-harmful air pollutant. Additionally, ozone is a short-lived climate forcer that contributes to global warming. In remote areas, methane is a dominant precursor to tropospheric ozone formation.[26] Approximately 50 percent of the global annual mean ozone increase since preindustrial times is believed to be due to anthropogenic methane.[27] Projections of future emissions also indicate that methane is likely to be a key contributor to ozone concentrations in the future.[28] Unlike nitrogen oxide (NO_X) and VOC, which affect ozone concentrations regionally and at hourly time scales, methane emissions affect ozone concentrations globally and on decadal time scales given methane's relatively long atmospheric lifetime compared to these other ozone precursors.[29] Reducing methane emissions, therefore, may contribute to efforts to reduce global background ozone concentrations that contribute to the incidence of ozone-related health effects.[30] [31] These benefits are global and occur in both urban and rural areas.

2. VOC

Tropospheric, or ground-level, ozone is formed through reactions of VOC and NO_X in the presence of sunlight. Ozone formation can be controlled to some extent through reductions in emissions of ozone precursor VOC and NO_X. A significantly expanded body of scientific evidence shows that ozone can cause a number of harmful effects on health and the environment. Exposure to ozone can cause respiratory system effects such as difficulty breathing and airway inflammation. For people with lung diseases such as asthma and chronic obstructive pulmonary disease (COPD), these effects can lead to emergency room visits and hospital admissions. Studies have also found that ozone exposure is likely to cause premature death from lung or heart diseases. In addition, evidence indicates that long-term exposure to ozone is likely to result in harmful respiratory effects, including respiratory symptoms and the development of asthma. People most at risk from breathing air containing ozone include: Children; people with asthma and other respiratory diseases; older adults; and people who are active outdoors, especially outdoor workers. An estimated 25.9 million people have asthma in the U.S., including almost 7.1 million children. Asthma disproportionately affects children, families with lower incomes, and minorities, including Puerto Ricans, Native Americans/Alaska Natives and African-Americans.[32]

Scientific evidence also shows that repeated exposure to ozone reduces growth and has other harmful effects on plants and trees. These types of effects have the potential to impact ecosystems and the benefits they provide.

3. SO_2

Current scientific evidence links short-term exposures to SO_2, ranging from 5 minutes to 24 hours, with an array of adverse respiratory effects including bronchoconstriction and increased asthma symptoms. These effects are particularly important for

[23] Blunden, J., and D.S. Arndt, Eds., 2014: State of the Climate in 2013. Bull. Amer. Meteor. Soc., 95 (7), S1–S238.

[24] *http://www.ncdc.noaa.gov/sotc/global/2014/13.*

[25] NRC, 2011: *America's Climate Choices,* The National Academies Press.

[26] U.S. EPA. 2013. ''Integrated Science Assessment for Ozone and Related Photochemical Oxidants (Final Report).'' EPA–600–R–10–076F. National Center for Environmental Assessment—RTP Division. Available at *http://www.epa.gov/ncea/isa/.*

[27] Myhre, G., D. Shindell, F.-M. Bréon, W. Collins, J. Fuglestvedt, J. Huang, D. Koch, J.-F. Lamarque, D. Lee, B. Mendoza, T. Nakajima, A. Robock, G. Stephens, T. Takemura and H. Zhang, 2013: Anthropogenic and Natural Radiative Forcing. In: Climate Change 2013: The Physical Science Basis. Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Stocker, T.F., D. Qin, G.-K. Plattner, M. Tignor, S.K. Allen, J. Boschung, A. Nauels, Y. Xia, V. Bex and P.M. Midgley (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA. Pg. 680.

[28] *Ibid.*

[29] *Ibid.*

[30] West, J.J., Fiore, A.M. 2005. ''Management of tropospheric ozone by reducing methane emissions.''*Environ. Sci. Technol.* 39:4685–4691.

[31] Anenberg, S.C., *et al.* 2009. ''Intercontinental impacts of ozone pollution on human mortality,'' *Environ. Sci. & Technol.* 43:6482–6487.

[32] National Health Interview Survey (NHIS) Data, 2011 *http://www.cdc.gov/asthma/nhis/2011/data.htm.*

asthmatics at elevated ventilation rates (*e.g.,* while exercising or playing).

Studies also show an association between short-term exposure and increased visits to emergency departments and hospital admissions for respiratory illnesses, particularly in at-risk populations including children, the elderly, and asthmatics.

SO_2 in the air can also damage the leaves of plants, decrease their ability to produce food—photosynthesis—and decrease their growth. In addition to directly affecting plants, SO_2 when deposited on land and in estuaries, lakes and streams, can acidify sensitive ecosystems resulting in a range of harmful indirect effects on plants, soils, water quality, and fish and wildlife (*e.g.,* changes in biodiversity and loss of habitat, reduced tree growth, loss of fish species). Sulfur deposition to waterways also plays a causal role in the methylation of mercury.[33]

4. Emission Estimates

Section VI.A above explains how GHGs, VOC, and SO_2 emissions are ''air pollution'' that may reasonably be anticipated to endanger public health and welfare. This section provides estimated emissions that the oil and natural gas source category contributes to this air pollution. As shown below, the contribution from this industry is quite significant.

a. GHG Emissions

Atmospheric concentrations of GHGs are now at essentially unprecedented levels compared to the distant and recent past.[34] This is the unambiguous result of emissions of these gases from human activities. Global emissions of well-mixed GHGs have been increasing, and are projected to continue increasing for the foreseeable future. According to IPCC AR5, total global emissions of GHGs in 2010 were about 49,000 million metric tons [35] of CO2 equivalent (MMT CO2eq).[36] This represents an increase in global GHG emissions of about 29 percent since 1990 and 23 percent since 2000. In 2010, total U.S. GHG emissions were responsible for about 14 percent of global GHG emissions (and about 12 percent when factoring in the effect of carbon sinks from U.S. land use and forestry).

Based on the Inventory of U.S. Greenhouse Gas Emissions and Sinks Report [37] (hereinafter ''U.S. GHG Inventory''), in 2013 total U.S. GHG emissions increased by 5.9 percent from 1990 (or by about 4.8 percent when including the effects of carbon sinks), and increased from 2012 to 2013 by 2.0 percent. This increase was attributable to multiple factors including increased carbon intensity of fuels consumed to generate electricity, a relatively cool winter leading to an increase in heating requirements, an increase in industrial production across multiple sectors and a small increase in vehicle miles traveled (VMT) and fuel use across on-road transportation modes.

Because 2010 is the most recent year for which IPCC emissions data are available, we provide 2011 estimates from the World Resources Institute's (WRI) Climate Analysis Indicators Tool (CAIT) [38] for comparison. According to WRI/CAIT, the total global GHG emissions in 2011 were 43,816 MMT of CO_2 Eq., representing an increase in global GHG emissions of about 42 percent since 1990 and 30 percent since 2000 (excluding land use, land use change and forestry). These estimates are generally consistent with those of IPCC. In 2011, WRI/CAIT data indicate that total U.S. GHG emissions were responsible for almost 15.5 percent of global emissions, which is also generally in line with the percentages using IPCC's 2010 estimate described above. According to WRI/CAIT, current U.S. GHG emissions rank only behind China's, which was responsible for 24 percent of total global GHG emissions.

i. Methane Emissions in the United States and from the Oil and Natural Gas Industry

The GHGs addressed by the 2009 Endangerment Finding consist of six well-mixed gases, including methane. Methane is a potent GHG with a 100 year GWP that is 28–36 times greater than that of carbon dioxide.[39] Methane has an atmospheric life of about 12 years. Official U.S. estimates of national level GHG emissions and sinks are developed by the EPA for the U.S. GHG Inventory to comply with commitments under the United Nations Framework Convention on Climate Change (UNFCCC). The U.S. inventory, which includes recent trends, is organized by industrial sectors. Natural gas and petroleum systems are the largest emitters of methane in the U.S. These systems emit 29 percent of U.S. anthropogenic methane.

Table 2 below presents total U.S. anthropogenic methane emissions for the years 1990, 2005 and 2013.

TABLE 2—U.S. METHANE EMISSIONS BY SECTOR

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

Sector	1990	2005	2013
Oil and Natural Gas Production, and Natural Gas Processing and Transmission	170.0	163.5	148.3
Enteric Fermentation	164.2	168.9	164.5
Landfills	186.2	165.5	114.6
Coal Mining	96.5	64.1	64.6
Manure Management	37.2	56.3	61.4
Other Methane Sources [40]	91.4	89.5	82.9

[33] U.S. EPA. Integrated Science Assessment (ISA) for Oxides of Nitrogen and Sulfur Ecological Criteria (2008 Final Report). U.S. Environmental Protection Agency, Washington, DC, EPA/600/R–08/082F, 2008.

[34] IPCC, 2013: *Summary for Policymakers. In: Climate Change 2013: The Physical Science Basis.* Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Stocker, T.F., D. Qin, G.-K. Plattner, M. Tignor, S.K. Allen, J. Boschung, A. Nauels, Y. Xia, V. Bex and P.M. Midgley (eds.)]. Cambridge University Press, p. 11.

[35] One MMT = 1 million metric tons = 1 megatonne (Mt). 1 metric ton = 1,000 kg = 1.102 short tons = 2,205 lbs.

[36] IPCC, 2014: *Climate Change 2014: Mitigation of Climate Change. Contribution of Working Group III to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change* [Edenhofer, O., R. Pichs-Madruga, Y. Sokona, E. Farahani, S. Kadner, K. Seyboth, A. Adler, I. Baum, S. Brunner, P. Eickemeier, B. Kriemann, J. Savolainen, S. Schlömer, C. von Stechow, T. Zwickel and J.C. Minx (eds.)]. Cambridge University Press, 1435 pp.

[37] U.S. EPA, 2014: *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2012.* Available at *http://www.epa.gov/climatechange/ghgemissions/usinventoryreport.html#fullreport* (Last accessed January 29, 2015).

[38] World Resources Institute (WRI) Climate Analysis Indicators Tool (CAIT) Data Explorer (Version 2.0). Available at *http://cait.wri.org.* (Last accessed October 31, 2014.)

[39] IPCC, 2013: Climate Change 2013: The Physical Science Basis. Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Stocker, T.F., D. Qin, G.-K. Plattner, M. Tignor, S.K. Allen, J. Boschung, A. Nauels, Y. Xia, V. Bex and P.M. Midgley (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, 1535 pp. Note that for purposes of inventories and reporting, GWP values from the 4th Assessment Report may be used.

TABLE 2—U.S. METHANE EMISSIONS BY SECTOR—Continued
[Million metric ton carbon dioxide equivalent (MMT CO_2 Eq.)]

Sector	1990	2005	2013
Total Methane Emissions	745.5	707.8	636.3

Emissions from the U.S. GHG Inventory, calculated using GWP of 25.

Oil and natural gas production and natural gas processing and transmission systems encompass wells, natural gas gathering and processing facilities, storage, and transmission pipelines. These components are all important aspects of the natural gas cycle—the process of getting natural gas out of the ground and to the end user. In the oil industry, some underground crude oil contains natural gas that is entrained in the oil at high reservoir pressures. When oil is removed from the reservoir, associated natural gas is produced.

Methane emissions occur throughout the natural gas industry. They primarily result from normal operations, routine maintenance, fugitive leaks and system upsets. As gas moves through the system, emissions occur through intentional venting and unintentional leaks. Venting can occur through equipment design or operational practices, such as the continuous bleed of gas from pneumatic controllers (that control gas flows, levels, temperatures, and pressures in the equipment), or venting from well completions during production. In addition to vented emissions, methane losses can occur from leaks (also referred to as fugitive emissions) in all parts of the infrastructure, from connections between pipes and vessels, to valves and equipment.

In petroleum systems, methane emissions result primarily from field production operations, such as venting of associated gas from oil wells, oil storage tanks, and production-related equipment such as gas dehydrators, pig traps, and pneumatic devices.

Table 3 (a and b) below present total methane emissions from natural gas and petroleum systems, and the associated segments of the sector, for years 1990, 2005 and 2013, in million metric tons of carbon dioxide equivalent (Table 3(a)) and kilotons (or thousand metric tons) of methane (Table 3(b)).

TABLE 3(a)—U.S. METHANE EMISSIONS FROM NATURAL GAS AND PETROLEUM SYSTEMS
[MMT CO_2 Eq.]

Sector	1990	2005	2013
Oil and Natural Gas Production and Natural Gas Processing and Transmission (Total)	170	163	148
Natural Gas Production	59	75	47
Natural Gas Processing	21	16	23
Natural Gas Transmission and Storage	59	49	54
Petroleum Production	31	23	24

Emissions from the 2015 U.S. GHG Inventory, calculated using GWP of 25.

TABLE 3(b)—U.S. METHANE EMISSIONS FROM NATURAL GAS AND PETROLEUM SYSTEMS
[kt CH_4]

Sector	1990	2005	2013
Oil and Natural Gas Production and Natural Gas Processing and Transmission (Total)	6,802	6,539	5,930
Natural Gas Production	2,380	3,018	1,879
Natural Gas Processing	852	655	906
Natural Gas Transmission and Storage	2,343	1,963	2,176
Petroleum Production	1,227	903	969

Emissions from the 2015 U.S. GHG Inventory, in kt (1,000 tons) of CH4.

ii. U.S. Oil and Natural Gas Production and Natural Gas Processing and Transmission GHG Emissions Relative to Total U.S. GHG Emissions

Relying on data from the U.S. GHG Inventory, we compared U.S. oil and natural gas production and natural gas processing and transmission GHG emissions to total U.S. GHG emissions as an indication of the role this source plays in the total domestic contribution to the air pollution that is causing climate change. In 2013, total U.S. GHG emissions from all sources were 6,673 MMT CO_2 Eq.

For purposes of the proposed revision to the category listing, the EPA is including oil and natural gas production sources, and natural gas processing transmission sources. In 2013, emissions from oil and natural gas production sources and natural gas processing and transmission sources accounted for 148 MMT CO_2eq methane emissions and oil completions for another 3 MMT CO2eq (using a GWP of 25 for methane). The sector also emitted 44 MMT of CO_2, mainly from acid gas removal during natural gas processing (22 MMT) and flaring in oil and natural gas production (16 MMT). In total, these emissions account for 3.0 percent of total U.S. domestic emissions.

In regard to the six well-mixed GHGs (CO_2, methane, nitrous oxide,

[40] Other sources include remaining natural gas distribution, petroleum transport and petroleum refineries, forest land, wastewater treatment, rice cultivation, stationary combustion, abandoned coal mines, petrochemical production, mobile combustion, composting, and several sources emitting less than 1 MMT CO_2-e in 2013.

hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride), only two of these gases—CO_2 and methane—are reported as non-zero emissions for the oil and natural gas production sources and natural gas processing and transmission sources that are being addressed within this rule.

TABLE 4—COMPARISONS OF U.S. OIL AND NATURAL GAS PRODUCTION AND NATURAL GAS PROCESSING AND TRANSMISSION GHG EMISSIONS TO TOTAL U.S. GHG EMISSIONS

	2010	2011	2012	2013
Total U.S. Oil & Gas Production and Natural Gas Processing & Transmission GHG Emissions (MMT CO_2 Eq)	147	147	146	148
Share of Total U.S. GHG Inventory	2.13%	2.18%	2.23%	2.22%
Total U.S. GHG Emissions (MMT CO_2 Eq)	6,899	6,777	6,545	6,673

iii. U.S. Oil and Natural Gas Production and Natural Gas Processing and Transmission GHG Emissions Relative to Total Global GHG Emissions

TABLE 5—COMPARISONS OF U.S. OIL AND NATURAL GAS PRODUCTION AND NATURAL GAS PROCESSING AND TRANSMISSION GHG EMISSIONS TO TOTAL GLOBAL GREENHOUSE GAS EMISSIONS IN 2010

	2010 (MMT CO_2 eq)	Total U.S. oil and natural gas production and natural gas processing and transmission share (%)
Total Global GHG Emissions	49,000	0.3%

For additional background information and context, we used 2011 WRI/CAIT and IEA data to make comparisons between U.S. oil and natural gas production and natural gas processing and transmission emissions and the emissions inventories of entire countries and regions. Ranking U.S. emissions of GHGs from oil and natural gas production and natural gas processing and transmission against total GHG emissions for entire countries, show that these emissions would be more than the national-level emissions totals for all anthropogenic sources for Greece, the Czech Republic, Chile, Belgium, and about 140 other countries.

As illustrated by the data summarized above, the collective GHG emissions from oil and natural gas production and natural gas processing and transmission sources are significant, whether the comparison is domestic (3.0 percent of total U.S. emissions) or global (0.3 percent of all global GHG emissions). The EPA believes that consideration of the global context is important. GHG emissions from U.S. oil and natural gas production and natural gas processing and transmission will become globally well-mixed in the atmosphere, and thus will have an effect on the U.S. regional climate, as well as the global climate as a whole for years and indeed many decades to come. Based on the data above, GHG emissions from the oil and natural gas source category is significiant whether only the domestic context is considered, only the global context is considered, or both the domestic and global GHG emissions comparisons are viewed in combination.

As was the case in 2009, no single GHG source category dominates on the global scale, and many (if not all) individual GHG source categories could appear small in comparison to the total, when, in fact, they could be very important contributors in terms of both absolute emissions or in comparison to other source categories, globally or within the U.S. Contributions of GHG to the global problem should not be compared to contributions associated with local air pollution problems. The EPA continues to believe that these unique, global aspects of the climate change problem—including that from a percentage perspective there are no dominating sources emitting GHGs and fewer sources that would even be considered to be close to dominating—tend to support consideration of contribution to the air pollution at lower percentage levels than the EPA typically encounters when analyzing contribution towards a more localized air pollution problem. Thus, the EPA, similar to the approach taken in the 2009 Finding, is placing significant weight on the fact that oil and natural gas production and natural gas processing and transmission sources contribute 3 percent of total U.S. GHG emissions for the contribution finding.

b. VOC Emissions

The EPA National Emissions Inventory (NEI) estimated total VOC emissions from the oil and natural gas sector to be 2,782,000 tons in 2011. This ranks second of all the sectors estimated by the NEI and first of all the anthropogenic sectors in the NEI.

c. SO_2 Emissions

The NEI estimated total SO_2 emissions from the oil and natural gas sector to be 74,000 tons in 2011. This ranks 13th of the sectors estimated by the NEI.

5. Conclusion

In summary, EPA interprets the 1979 category listing to broadly cover the oil and natural gas industry, including all segments of the natural gas industry (production, processing, transmission, and storage). To the extent there is ambiguity to the prior listing, EPA is proposing to revise the category listing to include the various segments of the natural gas industry. In support, EPA notes its previous determination under section 111(b)(1)(A) for the oil and natural gas source category. In addition, EPA provides in this section information and analyses detailing the public health and welfare impacts of GHG, VOC and SO_2 emissions and the amount of these emission from the oil and natural gas source category (in particular from the various segments of the natural gas industry). Although EPA does not believe the proposed revision to the category listing is required for the standards we are proposing in this action, even assuming it is, the proposal is well justified.

B. Stakeholder Input

1. White Papers

As a follow up to the 2013 Climate Action Plan, the Climate Action Plan: Strategy to Reduce Methane Emissions (the Methane Strategy) was released in March 2014. The Methane Strategy instructed the EPA to release a series of white papers on several potentially significant sources of methane in the oil and natural gas sector and solicit input from independent experts. The papers were released in April 2014, and focused on technical issues, covering emissions and control technologies that target both VOC and methane with particular focus on completions of hydraulically fractured oil wells, liquids unloading, leaks, pneumatic devices and compressors. The peer review process was completed on June 16, 2014.

The peer review and public comments on the white papers included additional technical information that provided further clarification of our understanding of the emission sources and emission control options. The comments also provided additional data on emissions and number of sources, and pointed out newly published studies that further informed our emission rate estimates. Where appropriate, we used the information and data provided to adjust the control options considered and the impacts estimates presented in the 2015 TSD.

The EPA used an ad hoc external peer review process, as outlined in the EPA's Peer Review Handbook, 3rd Edition. Under that process, the Agency submitted names recommended by industry and environmental groups, along with state, tribal, and academic organizations to an outside contractor. To avoid any conflict of interest, the contractor did not work on the white papers and is not working on the EPA's oil and natural gas regulations or voluntary programs. The contractor built a list of qualified reviewers from these names and their own research, reviewed appropriate credentials and selected reviewers from the list. A different set of reviewers was selected for each white paper, based on the reviewers' expertise. A total of 26 sets of comments from peer reviewers were submitted to the EPA. Additionally, the EPA solicited technical information and data from the public. The EPA received over 43,000 submissions from the public. The comments received from the peer reviewers are available on EPA's oil and natural gas white paper Web site (*http://www.epa.gov/airquality/oilandgas/methane.html*). Public comments on the white papers are available in EPA's nonregulatory docket at *www.regulations.gov*, docket ID # EPA–HQ–OAR–2014–0557.

2. Outreach to State, Local and Tribal Governments

The EPA spoke with state, local and tribal governments to hear how they have managed issues, and to get feedback that would help us as we develop the rule. In February 2015, the EPA asked states and tribes to nominate themselves to participate in discussions. Twelve states, three tribes and several local air districts participated. We conducted several teleconferences in March and April 2015 to discuss such questions as:

- Whether these governments are, or have considered, regulating the sources identified in the white papers
- Factors considered in determining whether to regulate them
- Use of innovative compliance options
- Experiences implementing control techniques guidelines (CTGs) [41]
- Information and features that would be helpful to include in a CTG
- Whether any sources of emissions are particularly suitable to voluntary rather than regulatory action

In addition to the outreach described above, the EPA consulted with tribal officials under the ''EPA Policy on Consultation and Coordination with Indian Tribes'' early in the process of developing this regulation to provide them with the opportunity to have meaningful and timely input into its development. Additionally, the EPA has conducted meaningful involvement with tribal stakeholders throughout the rulemaking process and provided an update on the methane strategy to the National Tribal Air Association. Consistent with previous actions affecting the oil and natural gas sector, there is significant tribal interest because of the growth of the oil and natural gas production in Indian country. The EPA specifically solicits additional comment on this proposed action from tribal officials.

[41] Control techniques guidelines are not part of this action.

VII. Summary of Proposed Standards

A. Control of Methane and VOC Emissions in the Oil and Natural Gas Source Category

In this action, we propose to set emission standards for methane and VOC for certain new, modified and reconstructed emission sources across the oil and natural gas source category. For some of these sources, there are VOC requirements currently in place that were established in the 2012 NSPS, that we are expanding to include methane. For others, for which there are no current requirements, we are proposing methane and VOC standards. We are also proposing improvements to enhance implementation of the current standards. For the reasons explained in section V, EPA believes that the proposed methane standards are warranted, even for those already subject to VOC standards under the 2012 NSPS. Further, as shown in the analyses in section VIII, there are cost effective controls that achieve simultaneous reductions of methane and VOC emission. Some stakeholders have advocated that is appropriate to rely on VOC standards, as established in 2012, for sources in the production and processing segment. For example, based on methane and VOC emissions from pneumatic controllers, this approach could result in just a VOC standard for pneumatic controllers in the production segment and a VOC and methane standard in the transmission and storage segment. Some stakeholders have also advocated for the importance of setting methane standards in the production segment that go beyond the 2012 NSPS standards. We anticipate that these stakeholders will express their views during the comment period.

Pursuant to CAA section 111(b), we are proposing to amend subpart OOOO and to create a new subpart OOOOa which will include the standards and requirements summarized in this section. Subpart OOOO would be amended to apply to facilities constructed, modified or reconstructed after August 23, 2011, (*i.e.*, the original proposal date of subpart OOOO) and before September 18, 2015 (*i.e.*, the proposal date of the new subpart OOOOa) and would be amended only to include the revisions reflecting implementation improvements in response to issues raised in petitions for reconsideration. Subpart OOOOa would apply to facilities constructed, modified or reconstructed after September 18, 2015 and would include current VOC requirements already provided in subpart OOOO as well as new provisions for methane and VOC across the oil and natural gas source category as highlighted below in this section. More details of the rationale for these proposed standards and requirements are provided in section VIII of this preamble.

We note that the terms ''emission source,'' ''source type'' and ''source,'' as used in this preamble, refer to equipment, processes and activities that emit VOC and/or methane. This term does not refer to specific facilities, in contrast to usage of the term ''source'' in the contexts of permitting and section 112 actions. As summarized below and discussed in more detail in section VIII, the BSER for methane is the same as that for VOC for all emission sources, including those currently subject to VOC standards and for which we are proposing to establish methane standards in this action. Accordingly, the current requirements reflect the BSER for both VOC and methane for these sources. We are, therefore, not proposing any change to the current requirements for emission sources addressed under the 2012 NSPS.

Both VOC and methane are hydrocarbon compounds and behave essentially the same when emitted together or separately. Accordingly, the available controls for methane are the same as those for VOC and achieve the same levels of reduction for both VOC and methane. For example, combustion-based control technologies (*e.g.*, flares and enclosed combustors) that reduce VOC emissions by 95 percent can be expected to also reduce methane emissions by 95 percent. Similarly, work practice and operational standards (*e.g.*, leak detection and reduced emission completion of wells) that reduce emissions of VOC can be expected to have the same effect on methane emissions. Because VOC control technologies perform the same when used to control methane emissions, the BSER for methane is the same as the BSER for VOC. Therefore, we are proposing performance and operational standards to control methane and VOC emissions for certain emission sources across the source category. These proposed methane standards would require no change to the requirements for currently regulated affected facilities.

Please note that there are minor differences in some values presented in various documents supporting this action. This is because some calculations have been performed independently (*e.g.*, TSD calculations focused on unit-level cost-effectiveness and RIA calculations focused on national impacts) and include slightly different rounding of intermediate values.

B. Centrifugal Compressors

We are proposing standards to reduce methane and VOC emissions from new, modified or reconstructed centrifugal compressors located across the oil and natural gas source category, except those located at well sites. As discussed in detail in section VIII.B, the proposed standards are the same as those currently required to control VOC from centrifugal compressors in the production segment. Specifically, we are proposing to require 95 percent reduction of the emissions from each wet seal centrifugal compressor affected facility. The standard can be achieved by capturing and routing the emissions utilizing a cover and closed vent system to a control device that achieves an emission reduction of 95 percent, or routing the captured emissions to a process. Consistent with the current VOC provisions for centrifugal compressors in the production segment, dry seal centrifugal compressors are inherently low-emitting and would not be affected facilities. These proposed standards are the same as for centrifugal compressors regulated in the 2012 final rule.

C. Reciprocating Compressors

For the reasons discussed in section VIII.C, we are proposing an operational standard for affected reciprocating compressors across the oil and natural gas source category, except those located at well sites, that requires either replacement of the rod packing based on usage or routing of rod packing emissions to a process via a closed vent system under negative pressure. The owner or operator of a reciprocating compressor affected facility would be required to monitor the duration (in hours) that the compressor is operated, beginning on the date of initial startup of the reciprocating compressor affected facility. When the hours of operation reach 26,000 hours, the owner or operator would be required to immediately change the rod packing. Owners or operators can elect to change the rod packing every 36 months in lieu of monitoring compressor operating hours. As an alternative to rod packing replacement, owners and operators may route the rod packing emissions to a process via a closed vent system operated at negative pressure. These proposed standards are the same as for reciprocating compressors regulated in the 2012 rule.

D. Pneumatic Controllers

For the reasons presented in section VIII.D, consistent with VOC standards in the 2012 NSPS for pneumatic controllers in the production segment, we are proposing to control methane and VOC emissions by requiring use of low-bleed controllers in place of high-bleed controllers *(i.e.*, natural gas bleed rate not to exceed 6 scfh) [42] at locations within the source category except for natural gas processing plants. For natural gas processing plants, consistent with the VOC emission standards in the 2012 NSPS, we are proposing to control methane and VOC emissions by requiring that pneumatic controllers have zero natural gas bleed rate (*i.e.*, they are operated by means other than natural gas, such as being driven by compressed instrument air). We are proposing that these standards apply to each newly installed, modified or reconstructed pneumatic controller (including replacement of an existing controller). Consistent with the current requirements under the 2012 NSPS for control of VOC emissions from pneumatic controllers in the production segment and at natural gas processing plants, the proposed standards provide exemptions for certain critical applications based on functional considerations. These proposed standards are the same as for pneumatic controllers regulated in the 2012 rule.

E. Pneumatic Pumps

For the reasons detailed in section VIII.E, we are proposing standards for natural gas-driven chemical/methanol pumps and diaphragm pumps. The proposed standards would require the methane and VOC emissions from new, modified and reconstructed natural gas-driven chemical/methanol pumps and diaphragm pumps located at any location (except for natural gas processing plants) throughout the source category to be reduced by 95 percent if a control device is already available on site. For pneumatic pumps located at a natural gas processing plant, the proposed standards would require the methane and VOC emissions from natural gas-driven chemical/methanol pumps and diaphragm pumps to be zero.

F. Well Completions

We are proposing operational standards for well completions at hydraulically fractured (or refractured) wells, including oil wells. The 2012 NSPS regulated well completions to

[42] Bleed rate can be documented through information provided by the controller manufacturer.

control VOC emissions from hydraulically fractured or refractured gas wells. These proposed standards are the same as for natural gas wells regulated in the 2012 rule. We identified two subcategories of hydraulically fractured wells for which well completions are conducted: (1) Non-wildcat and non-delineation wells; and (2) wildcat and delineation wells. A wildcat well, also referred to as an exploratory well, is a well drilled outside known fields or are the first well drilled in an oil or gas field where no other oil and gas production exists. A delineation well is a well drilled to determine the boundary of a field or producing reservoir.

As discussed in detail in section VIII.F, we are proposing operational standards for subcategory 1 (non-wildcat, non-delineation wells) requiring a combination of REC and combustion. Compared to combustion alone, we believe that the combination of REC and combustion will maximize gas recovery and minimize venting to the atmosphere. Furthermore, the use of traditional combustion control devices (*i.e.*, flares and enclosed combustion control devices), present local emissions impacts. The proposed standards for subcategory 2 wells (wildcat and delineation wells) require only combustion. For subcategory 1 wells, we are proposing to define the flowback period of an oil well completion as consisting of two distinct stages, the ''initial flowback stage'' and the ''separation flowback stage.'' The initial flowback stage begins with the onset of flowback and ends when the flow is routed to a separator. During the initial flowback stage, any gas in the flowback is not subject to control. However, the operator must route the flowback to a separator unless it is technically infeasible for a separator to function. The point at which the separator can function marks the beginning of the separation flowback stage. During this stage, the operator must route all salable quality gas from the separator to a flow line or collection system, re-inject the gas into the well or another well, use the gas as an on-site fuel source or use the gas for another useful purpose. If it is technically infeasible to route the gas as described above, or if the gas is not of salable quality, the operator must combust the gas unless combustion creates a fire or safety hazard or can damage tundra, permafrost or waterways. No direct venting of gas is allowed during the separation flowback stage. The separation flowback stage ends either when the well is shut in and the flowback equipment is permanently disconnected from the well, or on startup of production. This also marks the end of the flowback period. The operator has a general duty to safely maximize resource recovery safely and minimize releases to the atmosphere over the duration of the flowback period. The operator is also required to document the stages of the completion operation by maintaining records of (1) the date and time of the onset of flowback; (2) the date and time of each attempt to route flowback to the separator; (3) the date and time of each occurrence in which the operator reverted to the initial flowback stage; (4) the date and time of well shut in; and (5) date and time that temporary flowback equipment is disconnected. In addition, the operator must document the total duration of venting, combustion and flaring over the flowback period. All flowback liquids during the initial flowback period and the separation flowback period must be routed to a well completion vessel, a storage vessel or a collection system.

For subcategory 2 wells, we are proposing an operational standard that requires routing of the flowback into well completion vessels and commencing operation of a separator unless it is technically infeasible for the separator to function. Once the separator can function, recovered gas must be captured and directed to a completion combustion device unless combustion creates a fire or safety hazard or can damage tundra, permafrost or waterways. Operators would be required to maintain the same records described above for category 1 wells.

Consistent with the current VOC standards for hydraulically fractured gas wells, we are proposing that ''low pressure'' wells would remain affected facilities and would have the same requirements as subcategory 2 wells (wildcat and delineation wells). The term ''low pressure gas well'' is unchanged from the currently codified definition in the NSPS; however, we solicit comment on whether this definition appropriately indicates hydraulically fractured oil wells for which conducting an REC would be technologically infeasible and whether the term should be revised to address all wells rather than just gas wells.

We are also retaining the provision from the 2012 NSPS, now at § 60.5365a(a)(1), that a well that is refractured, and for which the well completion operation is conducted according to the requirements of § 60.5375a(a)(1) through (4), is not considered a modified well and therefore does not become an affected facility under the NSPS. We point out that such an exclusion of a ''well'' from applicability under the NSPS has no effect on the affected facility status of the ''well site'' for purposes of the proposed fugitive emissions standards at § 60.5397a.

Further, we are proposing that wells with a gas-to-oil ratio (GOR) of less than 300 scf of gas per barrel of oil produced would not be affected facilities subject to the well completion provisions of the NSPS. We solicit comment on whether a GOR of 300 is the appropriate applicability threshold. Rationale for this threshold is discussed in detail in section VIII.F.

G. Fugitive Emissions From Well Sites and Compressor Stations

1. Fugitive Emissions From Oil and Natural Gas Production Well Sites

We are proposing standards to reduce fugitive methane and VOC emissions from new and modified oil and natural gas production well sites. The proposed standards would require locating and repairing sources of fugitive emissions (*e.g.*, visible emissions from fugitive emissions components observed using OGI) at well sites. Under the proposed standards, the affected facility would be ''the collection of fugitive emissions components at a well site''; where ''well site'' is defined in subpart OOOO as ''one or more areas that are directly disturbed during the drilling and subsequent operation of, or affected by, production facilities directly associated with any oil well, gas well, or injection well and its associated well pad.'' This definition is intended to include all ancillary equipment in the immediate vicinity of the well that are necessary for or used in production, and may include such items as separators, storage vessels, heaters, dehydrators, or other equipment at the site.

Some well sites, especially in areas with very dry gas or where centralized gathering facilities are used, consist only of one or more wellheads, or ''Christmas trees,'' and have no ancillary equipment such as storage vessels, closed vent systems, control devices, compressors, separators and pneumatic controllers. Because the magnitude of fugitive emissions depends on how many of each type of component *(e.g.*, valves, connectors and pumps) are present, fugitive emissions from these well sites are extremely low. For that reason, we are proposing to exclude from the fugitive emissions requirements those well sites that contain only wellheads. Therefore, we are proposing to add the following sentence to the definition of ''well site'' above: ''For the purposes of the fugitive emissions standards at § 60.5397a, a well site that only contains one or more wellheads is not subject to these standards.''

Also, we are proposing to exclude low production well sites (*i.e.*, a low production site is defined by the average combined oil and natural gas production for the wells at the site being less than 15 barrels of oil equivalent (boe) per day averaged over the first 30 days of production) from the standards for fugitives emissions from well sites. Please refer to section VIII.G. for further discussion.

We are proposing that owners or operators of well site-affected facilities conduct an initial survey of ''fugitive emissions components,'' which we are proposing to define in § 60.5430a to include, among other things, valves, connectors, open-ended lines, pressure relief devices, closed vent systems and thief hatches on tanks using either OGI technology. For new well sites, the initial survey would have to be conducted within 30 days of the end of the first well completion or upon the date the site begins production, whichever is later. For modified well sites, the initial survey would be required to be conducted within 30 days of the site modification. We solicit comment on whether 30 days is an appropriate period for the first survey following startup or modification. For the purposes of these fugitive emissions standards, a modification would occur when a new well is added to a well site (regardless of whether the well is fractured) or an existing well on a well site is fractured or refractured. See section VII.G.3 below for a discussion of modifications in the context of fugitive emission requirements for well sites and compressor stations. After the initial monitoring survey, monitoring surveys would be required to be conducted semiannually for all new and modified well sites. We are also co-proposing monitoring surveys on an annual basis for new and modified well sites.

The proposed standards would require replacement or repair of components if evidence of fugitive emissions is detected during the monitoring survey through visible confirmation from OGI. As discussed in section VIII.G, we solicit comment on whether to allow EPA Method 21 as an alternative to OGI for monitoring, including the appropriate EPA Method 21 level repair threshold.

We are proposing that the source of emissions be repaired or replaced, and resurveyed, as soon as practicable, but no later than 15 calendar days after detection of the fugitive emissions. We expect that the majority of the repairs can be made at the time the initial monitoring survey is conducted. However, we understand that more time may be necessary to repair more complex components. We have historically allowed 15 days for repair/resurvey in the LDAR program, which has appeared to be sufficient time. We are proposing to allow the use of either Method 21 or OGI for resurveys that cannot be performed during the initial monitoring survey and repair. As explained above, there may be some components that cannot not be repaired right away and in some instances not until after the initial OGI personnel are no longer on site. In that event, resurvey with OGI would require rehiring OGI personnel, which would make the resurvey not cost effective. For those components that have been repaired, we believe that the no fugitive emissions would be detected above 500 ppm above background using Method 21. This has been historically used to ensure that there are no emissions from components that are required to operate with no detectable emissions. We solicit comments on whether either optical gas imaging or Method 21 should be allowed for the resurvey of the repaired components when fugitive emissions are detected with OGI. We estimate that the majority of operators will need to hire a contractor to come back to conduct the optical gas imaging resurvey. While there will also be costs associated with resurveying using Method 21, we estimate that many companies own Method 21 instruments (*e.g.,* OVA/TVA) and would be able to perform the resurvey at a minimal cost. To verify that the repair has been made using OGI, no evidence of visible emissions must be seen during the survey. For Method 21, we are proposing that the instrument show a reading of less than 500 ppm above background from any of the repaired components. We solicit comment whether 500 ppm above background is the appropriate repair resurvey threshold when Method 21 instruments are used or if not, what the appropriate repair resurvey threshold is for Method 21.

If the repair or replacement is technically infeasible or unsafe during unit operations, the repair or replacement must be completed during the next scheduled shutdown or within six months, whichever is earlier. Equipment is unsafe to repair or replace if personnel would be exposed to an immediate danger in conducting the repair or replacement. All sources of fugitive emissions that are repaired must be resurveyed within 15 days of repair completion to ensure the repair has been successful (*i.e.,* no fugitive emissions are imaged using OGI or less than 500 ppm above background when using Method 21).

The EPA is proposing that these fugitive emission requirements be carried out through the development and implementation of a monitoring plan, which would specify the measures for locating sources of fugitive emissions and the detection technology to be used. A company would be able to develop a corporate-wide monitoring plan, although there may be specific information needed that pertains to a single site, such as number and identification of fugitive emission components. The monitoring plan must also include a description of how the OGI survey will be conducted that ensures that fugitive emissions can be imaged effectively. In addition, we solicit comment on whether other techniques could be required elements of the monitoring plan in conjunction with OGI, such as visual inspections, to help identify signs such as staining of storage vessels or other indicators of potential leaks or improper operation.

If fugitive emissions are detected at less than one percent of the fugitive emission components at a well site during two consecutive semiannual monitoring surveys, then the monitoring survey frequency for that well site may be reduced to annually. If, during a subsequent monitoring survey, fugitive emissions are detected at between one percent and three percent of the fugitive emission components, then the monitoring survey frequency for that well site must be increased to semiannually.

If fugitive emissions are detected from three percent or more of the fugitive emission components at a well site during two consecutive semiannual monitoring, then the monitoring survey frequency for that well site must be increased to quarterly. If, during a subsequent monitoring survey, fugitive emissions are detected from one to three percent of the fugitive emission components, then the monitoring survey frequency for that well site may be reduced to semiannually. If fugitive emissions are detected from less than one percent of the fugitive emission components, then the monitoring survey frequency for that well site may be reduced to annually. We solicit comment on the proposed metrics of one percent and three percent and whether these thresholds should be specific numbers of components rather than percentages of components for triggering change in survey frequency discussed in this action. We also solicit comment on whether a performance-based frequency or a fixed frequency is more appropriate.

As discussed in more detail in section VIII.G below and the TSD for this action available in the docket, we have identified OGI technology with semiannual survey monitoring as the BSER for detecting fugitive emissions from new and modified well sites.

The proposed standards would apply to new well sites and to modified well sites. As explained in more detail in section VIII.B below, for purposes of this proposed standard, a well site is modified when a new well is completed (regardless of whether it is fractured) or an existing well is fractured or refractured after [effective date of final rule]. The standards would not apply to existing well sites where additional drilling activities were conducted on an existing well but those activities did not include fracturing or refracturing (e.g., well workovers that do not include fracturing or refracturing).

2. Fugitive Emissions From Compressor Stations

We are proposing standards to reduce fugitive methane and VOC emissions from new and modified natural gas compressor stations throughout the oil and natural gas source category. The proposed standards would require affected facilities to locate sources of fugitive emissions and to repair those sources. We are proposing that owners or operators of the affected facilities conduct an initial survey of the collection of fugitive emissions components (*e.g.,* valves, connectors, open-ended lines, pressure relief devices, closed vent systems and thief hatches on tanks) using OGI technology. For new compressor stations, the initial survey would have to be conducted within 30 days of site startup. For modified compressor stations, the initial survey would be required within 30 days of the site modification. After the initial survey, surveys would be required semiannually. We solicit comment on whether 30 days is an appropriate period for the first survey following startup.

The proposed standards would require replacement or repair of any fugitive emissions component that has evidence of fugitive emissions detected during the survey through visible confirmation from OGI. As discussed in section VIII.G, we solicit comment on whether to allow EPA Method 21 as an alternative to OGI for monitoring, including the appropriate EPA Method 21 level repair threshold.

We are proposing that the source of emissions be repaired or replaced, and resurveyed, as soon as practicable, but no later than 15 calendar days after detection of the fugitive emissions. We expect that the majority of the repairs can be made at the time the initial monitoring survey is conducted. However, we understand that more time may be necessary to repair more complex components. We have historically allowed 15 days for repair/resurvey in the LDAR program, which has appeared to be sufficient time. We are proposing to allow the use of either Method 21 or OGI for resurveys that cannot be performed during the initial monitoring survey and repair. As explained above, there may be some components that cannot not be repaired right away and in some instances not until after the initial OGI personnel are no longer on site. In that event, resurvey with OGI would require rehiring OGI personnel, which would make the resurvey not cost effective. For those components that have been repaired, we believe that the no fugitive emissions would be detected above 500 ppm above background using Method 21. This has been historically used to ensure that there are no emissions from components that are required to operate with no detectable emissions. We solicit comments on whether either optical gas imaging or Method 21 should be allowed for the resurvey of the repaired components when fugitive emissions are detected with OGI. We estimate that the majority of operators will need to hire a contractor to come back to conduct the optical gas imaging resurvey. While there will also be costs associated with resurveying using Method 21, we estimate that many companies own Method 21 instruments (*e.g.,* OVA/TVA) and would be able to perform the resurvey at a minimal cost. To verify that the repair has been made using OGI, no evidence of visible emissions must be seen during the survey. For Method 21, we are proposing that the instrument show a reading of less than 500 ppm above background from any of the repaired components. We solicit comment whether 500 ppm above background is the appropriate repair resurvey threshold when Method 21 instruments are used or if not, what the appropriate repair resurvey threshold is for Method 21.

The source of emissions must be repaired or replaced as soon as practicable, but no later than 15 calendar days after detection of the fugitive emissions. If the repair or replacement is technically infeasible or unsafe during unit operations, the repair or replacement must be completed during the next scheduled shutdown or within six months, whichever is earlier. Equipment is unsafe to repair or replace if personnel would be exposed to an immediate danger in conducting monitoring. All sources of fugitive emissions that are repaired must be resurveyed to ensure the repair has been successful (*i.e.,* no fugitive emissions are imaged using OGI or less than 500 ppm above background when using Method 21).

The EPA is proposing that these fugitive emission requirements be carried out through the development and implementation of a monitoring plan, which would specify the measures for locating sources of fugitive emissions and the detection technology to be used. The monitoring plan must also include a description of how the OGI survey will be conducted that ensures that fugitive emissions can be imaged effectively. In addition, we solicit comment on whether other techniques could be required elements of the monitoring plan in conjunction with OGI, such as visual inspections, to help identify signs such as staining of storage vessels or other indicators of potential leaks or improper operation.

If fugitive emissions are detected during two consecutive semi-annual monitoring surveys at less than one percent of the fugitive emission components, then the monitoring survey frequency for that compressor station may be reduced to annually. If, during a subsequent monitoring survey, visible fugitive emissions are detected using OGI from one to three percent of the fugitive emission components, then the monitoring survey frequency for that compressor station must be increased to semiannually.

If fugitive emissions are detected from three percent or more of the fugitive emission components during two consecutive semiannual monitoring surveys with OGI technology, then the monitoring survey frequency for that compressor station must be increased to quarterly. If, during a subsequent monitoring survey, fugitive emissions are detected from one to three percent of the fugitive emission components using OGI technology, then the monitoring survey frequency for that compressor station may be reduced to semiannually. If fugitive emissions are detected from less than one percent of the fugitive emission components, then the monitoring survey frequency for that well site may be reduced to annually. We solicit comment on the proposed metrics of one percent and three percent and whether these thresholds should be specific numbers of components rather than percentages of components for triggering change in survey frequency discussed in this action. We also solicit comment on whether a performance-based frequency or a fixed frequency is more appropriate.

As discussed in more detail in section VIII.G below and the TSD for this action available in the docket, we have identified OGI technology as the BSER for detecting fugitive emissions from new and modified compressor stations.

The proposed standards apply to new and modified compressor stations throughout the oil and natural gas source category. As explained in section VII.G.3 below, compressor stations are considered modified for the purposes of these fugitive emission standards when one or more compressors is added to the station after [effective date of final rule].

3. Modification of the Collection of Fugitive Emissions Components at Well Sites and Compressor Stations

For the purposes of the fugitive emission standards at well sites and compressor stations, we are proposing definitions of ''modification'' for those facilities that are specific to these provisions and for this purpose only. As provided in section 60.14(f), such provisions in the specific subparts would supersede any conflicting provisions in § 60.14 of the General Provisions. This definition does not affect other standards under this subpart for wells, other equipment at well sites or compressors.

For purposes of the proposed fugitive emissions standards at well sites, we propose that a modification to a well site occurs only when a new well is added to a well site (regardless of whether the well is fractured) or an existing well on a well site is fractured or refractured. When a new well is added or a well is fractured or refractured, there is an increase in emissions to the fugitive emissions components because of the addition of piping and ancillary equipment to support the well, along with potentially greater pressures and increased production brought about by the new or fractured well. Other than these events, we are not aware of any other physical change to a well site that would result in an increase in emissions from the collection of fugitive components at such well site. To clarify and ease implementation, we propose to define ''modification'' to include only these two events for purposes of the fugitive emissions provisions at well sites. We note that under § 60.5365a(a)(1) a well that is refractured, and for which the well completion operation is conducted according to the requirements of § 60.5375a(a)(1) through(4), is not considered a modified well and therefore does not become an affected facility under the NSPS. We would like to clarify that such an exclusion of a ''well'' from applicability under the NSPS would have no effect on the affected facility status of the ''well site'' for purposes of the proposed fugitive emissions standards. Accordingly, a well at an existing well site that is refractured constitutes a modification of the well site, which then would be an affected facility for purposes of the fugitive emission standards at § 60.5397a, regardless of whether the well itself is an affected facility.

In the 2012 NSPS, we provided that completion requirements do not apply to refracturing of an existing well that is completed responsibly (*i.e.* green completions). Building on the 2012 NSPS, the EPA intends to continue to encourage corporate-wide voluntary efforts to achieve emission reductions through responsible, transparent and verifiable actions that would obviate the need to meet obligations associated with NSPS applicability, as well as avoid creating disruption for operators following advanced responsible corporate practices. To encourage companies to continue such good corporate policies and encourage advancement in the technology and practices, we solicit comment on criteria we can use to determine whether and under what conditions well sites operating under corporate fugitive monitoring programs can be deemed to be meeting the equivalent of the NSPS standards for well site fugitive emissions such that we can define those regimes as constituting alternative methods of compliance or otherwise provide appropriate regulatory streamlining. We also solicit comment on how to address enforceability of such alternative approaches (*i.e.,* how to assure that these well sites are achieving, and will continue to achieve, equal or better emission reduction than our proposed standards).

For the reasons stated above, we are also soliciting comments on criteria we can use to determine whether and under what conditions all new or modified well sites or compressor stations operating under corporate fugitive monitoring programs can be deemed to be meeting the equivalent of the NSPS standards for well sites or compressor stations fugitive emissions such that we can define those regimes as constituting alternative methods of compliance or otherwise provide appropriate regulatory streamlining. We also solicit comment on how to address enforceability of such alternative approaches (*i.e.*, how to assure that these well sites and compressor stations are achieving, and will continue to achieve, equal or better emission reduction than our proposed standards).

For purposes of the proposed standards for fugitive emission at compressor stations, we propose that a modification occurs only when a compressor is added to the compressor station or when physical change is made to an existing compressor at a compressor station that increases the compression capacity of the compressor station. Since fugitive emissions at compressor stations are from compressors and their associated piping, connections and other ancillary equipment, expansion of compression capacity at a compressor station, either through addition of a compressor or physical change to the an existing compressor, would result in an increase in emissions to the fugitive emissions components. Other than these events, we are not aware of any other physical change to a compressor station that would result in an increase in emissions from the collection of fugitive components at such compressor station. To clarify and ease implementation, we define ''modification'' as the addition of a compressor for purposes of the fugitive emissions provisions at compressor stations.

H. Equipment Leaks at Natural Gas Processing Plants

We are proposing standards to control methane and VOC emissions from equipment leaks at natural gas processing plants. These requirements are the same as the VOC equipment leak requirements in the 2012 NSPS and would require NSPS part 60, subpart VVa level of control, including a detection level of 500 ppm as in the 2012 NSPS. As discussed further in section VIII.H, we propose that the subpart VVa level of control applied plant-wide is the BSER for controlling methane emissions from equipment leaks at onshore natural gas processing plants. We believe it provides the greatest emission reductions of the options we considered in our analysis in Section VIII.H, and that the costs are reasonable.

I. Liquids Unloading Operations

For the reasons discussed in section VIII.I, at this time the EPA does not have sufficient information to propose a standard for liquids unloading. However, we are requesting comment on nationally applicable technologies and techniques that reduce methane and VOC emissions from these events.

Specifically, we request comment on technologies and techniques that can be applied to new gas wells that can reduce emissions from liquids unloading in the future.

J. Recordkeeping and Reporting

We are proposing recordkeeping and reporting requirements that are consistent with those required in the current NSPS for natural gas well completions, compressors and pneumatic controllers. Owners or operators would be required to submit initial notifications (except for wells, pneumatic controllers, pneumatic pumps and compressors, as provided in § 60.5420(a)(1)) and annual reports, and to retain records to assist in documenting that they are complying with the provisions of the NSPS.

For new, modified or reconstructed pneumatic controllers, owners and operators would not be required to submit an initial notification; they would simply need to report the installation of these affected facilities in their facility's first annual report following the compliance period during which they were installed. Owners or operators of well-affected facilities (consistent with current requirements for gas well affected facilities) would be required to submit an initial notification no later than two days prior to the commencement of each well completion operation. This notification would include contact information for the owner or operator, the American Petroleum Institute (API) well number, the latitude and longitude coordinates for each well, and the planned date of the beginning of flowback.

In addition, an initial annual report would be due no later than 90 days after the end of the initial compliance period, which is established in the rule. Subsequent annual reports would be due no later than the same date each year as the initial annual report. The annual reports would include information on all affected facilities owned or operated of sources that were constructed, modified or reconstructed during the reporting period. A single report may be submitted covering multiple affected facilities, provided that the report contains all the information required by 40 CFR 60.5420(b). This information would include general information on the facility (*i.e.*, company name and address, etc.), as well as information specific to individual affected facilities.

For well affected facilities, the information required in the annual report would include the location of the well, the API well number, the date and time of the onset of flowback following hydraulic fracturing or refracturing, the date and time of each attempt to direct flowback to a separator, the date and time of each occurrence of returning to the initial flowback stage, and the date and time that the well was shut in and the flowback equipment was permanently disconnected or the startup of production, the duration of flowback, the duration of recovery to the flow line, duration of combustion, duration of venting, and specific reasons for venting in lieu of capture or combustion. For each oil well for which an exemption is claimed for conditions in which combustion may result in a fire hazard or explosion or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost or waterways, the report would include the location of the well, the API well number, the specific exception claimed, the starting date and ending date for the period the well operated under the exception, and an explanation of why the well meets the claimed exception. The annual report would also include records of deviations where well completions were not conducted according to the applicable standards.

For centrifugal compressor affected facilities, information in the annual report would include an identification of each centrifugal compressor using a wet seal system constructed, modified or reconstructed during the reporting period, as well as records of deviations in cases where the centrifugal compressor was not operated in compliance with the applicable standards.

For reciprocating compressors, information in the annual report would include the cumulative number of hours of operation or the number of months since initial startup or the previous reciprocating compressor rod packing replacement, whichever is later, or a statement that emissions from the rod packing are being routed to a process through a closed vent system under negative pressure.

Information in the annual report for pneumatic controller affected facilities would include location and documentation of manufacturer specifications of the natural gas bleed rate of each pneumatic controller installed during the compliance period. For pneumatic controllers for which the owner is claiming an exemption to the standards, the annual report would include documentation that the use of a pneumatic controller with a natural gas bleed rate greater than 6 scfh is required and the reasons why. The annual report would also include records of deviations from the applicable standards.

For pneumatic pump affected facilities, information in the annual report would include an identification of each pneumatic pump constructed, modified or reconstructed during the compliance period, as well as records of deviations in cases where the pneumatic pump was not operated in compliance with the applicable standards.

The proposed rule includes new requirements for monitoring and repairing sources of fugitive emissions at well sites and compressor stations. The owner or operator would be required to keep one or more digital photographs of each affected well site or compressor station. A photograph of every component that is surveyed during the monitoring survey is not required. The photograph must include the date the photograph was taken and the latitude and longitude of the well site imbedded within or stored with the digital file and must identify the affected facility. This could include a ''still'' image taken using OGI technology or a digital photograph taken of the survey being performed. As an alternative to imbedded latitude and longitude within the digital photograph, the digital photograph may consist of a photograph of the affected facility with a photograph of a separately operating Geographic Information Systems (GIS) device within the same digital picture, provided the latitude and longitude output of the GIS unit can be clearly read in the digital photograph. The owner or operator would also be required to keep a log for each affected facility. The log must include the date monitoring surveys were performed, the technology used to perform the survey, the monitoring frequency required at the time of the survey, the number and types of equipment found to have fugitive emissions, the date or dates of first attempt to repair the source of fugitive emissions, the final repair of each source of fugitive emissions, any source of fugitive emissions found to be technically infeasible or unsafe to repair during unit operation and the date that source is scheduled to be repaired. These digital photographs and logs must be available at the affected facility or the field office. We solicit comment on whether these records also should be sent directly to the permitting agency electronically to facilitate review remotely. The owner or operator would also be required to develop and maintain a corporate-wide and site specific monitoring plan enabling the fugitive emissions monitoring program.

Annual reports for each fugitive emissions affected facility would have to be submitted that include the date monitoring surveys were performed, the technology used to perform the survey, the monitoring frequency required at the time of the survey, the number and types of component found to have fugitive emissions, the date of first attempt to repair the source of fugitive emissions, the date of final repair of each source of fugitive emissions, any source of fugitive emissions found to be technically infeasible or unsafe to repair during unit operation and the date that source is scheduled to be repaired.

Consistent with the current requirements of subpart OOOO, records must be retained for 5 years and generally consist of the same information required in the initial notification and annual reports. The records may be maintained either onsite or at the nearest field office. We solicit comment on whether these records also should be sent directly to the permitting agency electronically to facilitate review remotely.

Lastly, the EPA realizes that duplicative recordkeeping and reporting requirements may exist between the NSPS, Subpart W, and other state and local rules, and is trying to minimize overlapping requirements on operators. We solicit comment on ways to minimize recordkeeping and reporting burden.

VIII. Rationale for Proposed Action for NSPS

The following sections provide our BSER analyses and the resulting proposed new source performance standards to reduce methane and VOC emissions from across the oil and natural gas source category. Our general process for evaluating BSER for the emission sources discussed below included: (1) Identification of available control measures; (2) evaluation of these measures to determine emission reductions achieved, associated costs, nonair environmental impacts, energy impacts and any limitations to their application; and (3) selection of the control techniques that represent BSER.

As mentioned previously and discussed in more detail below, the control technologies available for reducing methane and VOC emissions are the same for the emissions sources in this source category. This observation was made in the 2014 white papers and confirmed by the comments received on the 2014 white papers, as well as state regulations, including those of Colorado, that require methane and VOC mitigation measures from these sources of emissions.

CAA Section 111 also requires that EPA considers cost in determining BSER. Section VIII.A below describes how EPA evaluates the cost of control for purposes of this rulemaking. Sections VIII.B through VIII.I provide the BSER analysis and the resulting proposed standards for individual emission sources contemplated in this action.

Please note that there are minor differences in some values presented in various documents supporting this action. This is because some calculations have been performed independently *(e.g.*, TSD calculations focused on unit-level cost-effectiveness and RIA calculations focused on national impacts) and include slightly different rounding of intermediate values.

A. How does EPA evaluate control costs in this action?

Section 111 requires that EPA consider a number of factors, including cost, in determining ‘‘the best system of emission reduction . . . adequately demonstrated.’’ While section 111 requires that EPA consider cost in determining such system (*i.e.*, ‘‘BSER’’), it does not prescribe any criteria for such consideration. However, in several cases, the D.C. Circuit has shed light on how EPA is to consider cost under CAA section 111(a)(1). For example, in *Essex Chemical Corp.* v. *Ruckelshaus*, 486 F.2d 427, 433 (D.C. Cir. 1973), the D.C. Circuit stated that to be ‘‘adequately demonstrated,’’ the system must be ‘‘reasonably reliable, reasonably efficient, and . . . reasonably expected to serve the interests of pollution control without becoming exorbitantly costly in an economic or environmental way.’’ The Court has reiterated this limit in subsequent case law, including *Lignite Energy Council* v. *EPA*, 198 F.3d 930, 933 (D.C. Cir. 1999), in which it stated: ‘‘EPA's choice will be sustained unless the environmental or economic costs of using the technology are exorbitant.’’ In *Portland Cement Ass'n* v. *EPA*, 513 F.2d 506, 508 (D.C. Cir. 1975), the Court elaborated by explaining that the inquiry is whether the costs of the standard are ‘‘greater than the industry could bear and survive.’’[43] In *Sierra Club* v. *Costle*, 657 F.2d 298, 343 (D.C. Cir. 1981), the Court provided a substantially similar formulation of the cost standard when it held: ‘‘EPA concluded that the Electric Utilities' forecasted cost was not excessive and did not make the cost of compliance with the standard unreasonable. This is a judgment call with which we are not inclined to quarrel.’’ We believe that these various formulations of the cost standard—‘‘exorbitant,’’ ‘‘greater than the industry could bear and survive,’’ ‘‘excessive,’’ and ‘‘unreasonable’’—are synonymous; the DC Circuit has made no attempt to distinguish among them. For convenience, in this rulemaking, we will use reasonable to describe our evaluation of costs well within the boundaries established by this case law.

In evaluating whether the cost of a control is reasonable, EPA considers various costs associated with such control, including capital costs and operating costs, and the emission reductions that the control can achieve. A cost-effectiveness analysis is one means of evaluating whether a given control achieves emission reduction at a reasonable cost. Cost-effectiveness analysis also allows comparisons of relative costs and outcomes (effects) of two or more options. In general, cost-effectiveness is a measure of the benefit produced by resources spent. In the context of air pollution control options, cost-effectiveness typically refers to the annualized cost of implementing an air pollution control option divided by the amount of pollutant reductions realized annually. A cost-effectiveness analysis is not intended to constitute or approximate a cost-benefits analysis but rather provides a metric of the relative cost to reduction ratios of various control options.

The estimation and interpretation of cost-effectiveness values is relatively straightforward when an abatement measure controls a single pollutant. Increasingly, however, air pollution reduction programs require reductions in emissions of multiple pollutants, and in such programs multipollutant controls may be employed. Consequently, there is a need for determining cost-effectiveness for a control option across multiple pollutants (or classes of multiple pollutants). This is the case for this proposal where, for the reasons explained in section V, we are proposing to directly regulate both methane and VOC. Further, as discussed

[43] The 1977 House Committee Report noted: In the [1970] Congress [sic: Congress's] view, it was only right that the costs of applying best practicable control technology be considered by the owner of a large new source of pollution as a normal and proper expense of doing business. 1977 House Committee Report at 184. Similarly, the 1970 Senate Committee Report stated:

The implicit consideration of economic factors in determining whether technology is ‘‘available’’ should not affect the usefulness of this section. The overriding purpose of this section would be to prevent new air pollution problems, and toward that end, maximum feasible control of new sources at the time of their construction is seen by the committee as the most effective and, in the long run, the least expensive approach. S. Comm. Rep. No. 91–1196 at 16.

in more detail below, both methane and VOC are simultaneously and equi-proportionally reduced when controlled.

We have evaluated a number of approaches for considering the costs of the available multipollutant controls for reducing both methane and VOC emissions. One approach is to assign the entire annualized cost to the reduction in emissions of a single pollutant reduced by the multipollutant control option and treat the simultaneous reductions of the other pollutants as incidental or co-benefits. This was the approach we took in the 2012 NSPS but no longer believe to be appropriate for the reasons explained in section V. Under the current proposal, methane and VOCs are both directly regulated; therefore, reductions of each pollutant must be properly considered benefits, not co-benefits, and consideration of only one of the regulated pollutants is not appropriate.

Alternatively, all annualized costs can be allocated to each of the pollutant emission reductions addressed by the multipollutant control option. Unlike the approach above, no emission reduction is treated as co-benefit; each emission reduction is assessed based on the full cost of the control. However, this approach, which is often used for assessing single pollutant controls, evaluates emission reduction of each pollutant separately, assuming that each bears the entire cost, and thus inflates the control cost in the multiple of the number of additional pollutants being reduced. This type of approach therefore over-estimates the cost of obtaining emissions reductions with a multipollutant control as it does not recognize the simultaneity of the reductions achieved by the application of the control option.

Another type of approach allocates the annualized cost to the sum of the individual pollutant emission reductions addressed by the multipollutant control option. The multipollutant cost-effectiveness approach may be appropriate when each of the pollutant reductions is similar in value or impact. However, methane and VOC have quite different health and environmental impacts. Summing the pollutants to derive the denominator of the cost-effectiveness equation is inappropriate for this reason. Similarly, if the multiple pollutants could be combined with like units—for example, via economic valuation—the pollutants could be summed. We also think that this approach would be inappropriate here.

For purposes of this proposal, we have identified and are proposing to use two types of approaches for considering the cost of reducing emissions from multiple pollutants using one control. One approach assigns all costs to the emission reduction of one pollutant and zero to all other concurrent reductions; if the cost is reasonable for reducing any of the targeted emissions alone, the cost of such control is clearly reasonable for the concurrent emission reduction of all the other pollutants because they are being reduced at no additional cost. This approach acknowledges the reductions as intended as opposed to incidental or co-benefits. It also reflects the actual overall cost of the control. While this approach assigns all costs to only a portion of the emission reduction and thus may overstate the cost for that assigned portion, it does not overstate the overall cost. It also does not require evaluating in aggregate the benefits of methane and VOC emission reduction, which is not appropriate as discussed in the option immediately above. In addition, this approach is simple and straightforward in application. If the multipollutant control is cost-effective for reducing emissions of either of the targeted pollutant, it is clearly cost-effective for reducing all other targeted emissions that are being achieved simultaneously.

A second approach, which we term for the purpose of this rulemaking a ''multipollutant cost-effectiveness'' approach, apportions the annualized cost across the pollutant reductions addressed by the control option in proportion to the relative percentage reduction of each pollutant controlled. For example, in this proposal both methane and VOC emissions are reduced in equal proportion by the multipollutant control option. As a result, half of the control costs are allocated to methane, the other half to VOC. This approach similarly does not inflate the control cost nor requires evaluating in aggregate the benefits of methane and VOC emission reduction.

We believe that both approaches discussed above are appropriate for assessing the reasonableness of the multipollutant controls considered in this action. As such, in our analyses below, if a device is cost-effective under either of these two approaches, we find it to be cost-effective. EPA has considered similar approaches in the past when considering multiple pollutants that are controlled by a given control option.[44] The EPA recognizes, however, not all situations where multipollutant controls are applied are the same, and that other types of approaches, including those described above as inappropriate for this action, might be appropriate in other instances. The EPA solicits comments on the approaches to estimate cost-effectiveness for emissions reductions using multipollutant controls assessed in this action.

In considering control costs, the EPA takes into account any expected revenues from the sale of natural gas product that would be realized as a result of avoided emissions. Although no D.C. Circuit case addresses how to account for revenue generated from the byproducts of pollution control, or product saved as a result of control, it is logical and a reasonable interpretation of the statute that any expected revenues from the sale of recovered product may be considered when determining the overall costs of implementation of the control technology. Clearly, such a sale would offset regulatory costs and so must be included to accurately assess the costs of the standard. In our analysis we consider any natural gas that is either recovered or that is not emitted as a result of a control option as being ''saved.'' We estimate that one thousand standard cubic feet (Mcf) of natural gas is valued at $4.00.[45] Our cost analysis then applies the monetary value of the saved natural gas as an offset to the control cost. This offset applies where, in our estimation, the monetary savings of the natural gas saved can be realized by the affected facility owner or operator and not where the owner or operator does not own the gas and would not likely realize the monetary value of the natural gas saved (*e.g.*, transmission stations and storage facilities). Detailed discussions of these assumptions are presented in Chapter 3 of the RIA associated with this action, which is in the Docket.

We also completed two additional analyses to further inform our determination of whether the cost of control is reasonable, similar to compliance cost analyses we have completed for other NSPS.[46] First, we compared the capitals costs that would be incurred to comply with the

[44] See *e.g.* 73 FR 64079–64083 and EPA Document I.D. EPA–HQ–OAR–2004–0022–0622, EPA–HQ–OAR–2004–0022–0447, EPA–HQ–OAR–2004–0022–0448.

[45] The Energy Information Administration's 2014 Annual Energy Outlook forecasted wellhead prices paid to lower 48 state producers to be $4.46/Mcf in 2020 and $5.06/Mcf in 2025. The $4/Mcf price assumed in the RIA is intended to reflect the AEO estimate but simultaneously be conservatively low.

[46] For example, see our compliance cost analysis in ''Regulatory Impact Analysis (RIA) for Residential Wood Heaters NSPS Revision. Final Report.'' U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards. EPA–452/R–15–001, February 2015.

proposed standards to the industry's estimated new annual capital expenditures. This analysis allowed us to compare the capital costs that would be incurred to comply with the proposed standards to the level of new capital expenditures that the industry is incurring in the absence of the proposed standards. We then determined whether the capital costs appear reasonable in comparison to the industry's current level of capital spending. Second, we compared the annualized costs that would be incurred to comply with the standards to the industry's estimated annual revenues. This analysis allowed us to evaluate the annualized costs as a percentage of the revenues being generated by the industry.

EPA evaluated incremental capital cost in prior new source performance standards, and its determinations that the costs were reasonable were upheld by the courts. For example, the EPA estimated that the costs for the 1971 NSPS for coal-fired electric utility generating units were $19 million for a 600 MW plant, consisting of $3.6 million for particulate matter controls, $14.4 million for sulfur dioxide controls, and $1 million for nitrogen oxides controls, representing a 15.8 percent increase in capital costs above the $120 million cost of the plant. See 1972 Supplemental Statement, 37 FR 5767, 5769 (March 21, 1972). The D.C. Circuit upheld the EPA's determination that the costs associated with the final 1971 standard were reasonable, concluding that the EPA had properly taken costs into consideration. *Essex Cement* v. *EPA*, 486 F. 2d at 440. Similarly, in *Portland Cement Association*, the D.C. Circuit upheld the EPA's consideration of costs for a standard of performance that would increase capital costs by about 12 percent, although the rule was remanded due to an unrelated procedural issue. 486 F.2d at 387–88. Reviewing the EPA's final rule after remand, the court again upheld the standards and the EPA's consideration of costs, noting that ''[t]he industry has not shown inability to adjust itself in a healthy economic fashion to the end sought by the Act as represented by the standards prescribed.'' *Portland Cement* v. *Ruckelshaus*, 513 F. 2d 506, 508 (D.C. Cir. 1975). As shown below in the BSER analysis for each of the proposed standards, the associated increase in capital cost is well below the percentage increase previously upheld by the Court, and the annualized cost is but less than 1 percent of the annual revenue.

Capital expenditure data for relevant NAICS codes were obtained from the U.S. Census 2013 Annual Capital Expenditures Survey.[47] Annual revenue data for relevant NAICS codes were obtained from the U.S. Census 2012 County Business Patterns and 2012 Economic Census.[48] For both the capital expenditures and annual revenues, we obtained the Census data and performed the analyses on an affected facility basis rather than an industry-wide basis. We did this to better reflect the fact that different owners or operators are generally involved in the different industry segments. Thus, an industry-wide analysis would likely not be representative of the cost impacts on owners and operators within each segment. Although there is not a one-to-one correspondence between NAICS codes and the industry segments we used in the development of the cost impacts, we believe there is enough similarity to draw accurate conclusions from our analysis.

For the capital expenditures analysis, we determined the estimated nationwide capital costs incurred by each type of affected facility to comply with the proposed standards, then divided the nationwide capital costs by the new capital expenditures (Census data) for the appropriate NAICS code(s) to determine the percentage that the nationwide capital costs represent of the capital expenditures. Similarly, for the annual revenues analysis, we determined the estimated nationwide annualize costs incurred by each type of affected facility to comply with the proposed standards, then divided the nationwide annualized costs by the annual revenues (Census data) for the appropriate NAICS code(s) to determine the percentage that the nationwide annualized costs represent of annual revenues. These percentages are presented below in this section for each affected facility.

B. Proposed Standards for Centrifugal Compressors

In the 2012 NSPS, we established VOC standards for wet seal centrifugal compressors in the production segment of the oil and natural gas source category. Specifically, the standards apply to centrifugal compressors located after the well site and before transmission and storage segments because our data indicate that there are no centrifugal compressors in use at well sites.[49] In this action, we are proposing to extend these VOC standards to the remaining wet seal centrifugal compressors in the source category. We are also proposing methane standards for all wet seal centrifugal compressors in the oil and natural gas source category. Based on the analysis below, the proposed VOC and methane standards described above are the same as the wet seal centrifugal compressor standards currently in the NSPS.

Centrifugal compressors are used throughout the natural gas industry[50] to move natural gas along the pipeline. They are a source of methane and VOC emissions. These compressors are powered by turbines. They use a small portion of the natural gas that they compress to fuel the turbine. Sometimes an electric motor is used to turn a centrifugal compressor.

Centrifugal compressors require seals around the rotating shaft to minimize gas leakage from the point at which the shaft exits the compressor casing. There are two types of seal systems: Wet seal systems and mechanical dry seal systems.

Wet seal systems use oil, which is circulated under high pressure between three or more rings around the compressor shaft, forming a barrier to minimize compressed gas leakage. Very little gas escapes through the oil barrier, but considerable gas is absorbed by the oil. The amount of gas absorbed and entrained by the oil barrier is affected by the operating pressure of the gas being handled; higher operating pressures result in higher absorption of gas into the oil. Seal oil is purged of the absorbed and entrained gas (using heaters, flash tanks and degassing techniques) and recirculated to the seal area for reuse. Gas that is purged from the seal oil is commonly vented to the atmosphere. Degassing of the seal oil emits an average of 47.7 standard cubic feet per minute (scfm) of methane,[51] depending on the operating pressure of the compressor. Based on the average gas composition, which varies among segments of the natural gas industry, we estimate methane emission during the venting process of an uncontrolled wet seal system to be, on average, 228 tpy

[47] *http://www.census.gov/econ/aces/xls/2013/full_report.html.*

[48] For information on confidentiality protection, sampling error, and nonsampling error, see *http://www.census.gov/econ/susb/methodology.html.* For definitions of estimated receipts and other definitions, see *http://www.census.gov/econ/susb/definitions.html.*

[49] Since the 2012 NSPS, we have not received information that would change our understanding that there are no centrifugal compressors in use at well sites.

[50] See previous footnote regarding centrifugal compressors at well sites.

[51] Factors came from U.S. Environmental Protection Agency. Methodology for Estimating CH_4 and CO_2 Emissions from Natural Gas Systems. Greenhouse Gas Inventory: Emission and Sinks 1990–2012. Washington, DC. Annex 3.5. Table A–129.

in the production segment, 157 tpy in the transmission segment and 117 tpy in the storage segment. We estimate the VOC emissions to be, on average, approximately 4.34 tpy VOC in the transmission segment and 3.24 tpy of VOC in the storage segment.[52]

Dry seal systems do not use any circulating seal oil. Dry seals operate mechanically under the opposing force created by hydrodynamic grooves and springs. Fugitive emissions occur from dry seals around the compressor shaft. Based on manufacturer studies and engineering design estimates, fugitive emissions from dry seal systems are approximately 6 scfm of gas, much lower than wet seal systems. A dry seal system can have fugitive methane emissions of, on average, approximately 28.6 tpy in the processing segment, and 19.7 tpy in the transmission segment and 14.7 tpy in the storage segment. Likewise, VOC emissions are estimated to be 0.5 tpy in the transmission segment and 0.4 tpy in the storage segment.[53] In the 2012 NSPS, we did not regulate fugitive VOC emissions from dry seal compressors because we did not identify any control device suitable to capture and control such emissions. For the same reasons we explained in the 2012 NSPS, we are not proposing methane standards for dry seal compressors.

The available control techniques for reducing methane and VOC emissions from degassing of wet seal systems are the same. These include routing the gas to a process and routing the gas to a combustion device. We also consider replacing wet seal system with a dry seal system due to its inherent low emissions. These are the same options we previously identified for controlling fugitive VOC emissions from degassing of wet seal compressors. We did not find other available control options from our white paper process or information review.

During the rulemakings for the 2012 NSPS and subsequent amendments, we found that the dry seal system had inherently low VOC emissions and the option of routing to a process had at least 95 percent control efficiency. However, the integration of a centrifugal compressor into an operation may require a certain compressor size or design that is not available in a dry seal model, or in the case of capture of emissions with routing to a process, there may not be down-stream equipment capable of handling a low pressure fuel source. As such, these two options not technically feasible in all instances and, therefore, neither was the BSER for reducing fugitive VOC emissions from wet seal centrifugal compressors. Available information since then continues to show that that these two options cannot be used in all circumstances. For the same reasons, these options do not qualify as BSER for reducing methane emissions from wet seal centrifugal compressors.

In the 2012 NSPS rulemaking, we found that a capture and combustion device (option 3) had a 95 percent VOC emission reduction efficiency. Available information since then continues to support that such device can achieve 95 percent control efficiency and for both methane and VOC emissions. Based on the average uncontrolled emissions of wet seal systems discussed above and a capture and combustion device system efficiency of 95 percent, we determined that methane emissions from a wet seal system in the processing segment would be reduced by 217 tpy, by 149 tpy in the transmission segment and by 111 tpy in the storage segment. The VOC emissions would be reduced by 4.12 tpy in the transmission segment and by 3 tpy in the storage segment.[54]

For purposes of this action, we have identified in section VIII.A two approaches for evaluating whether the cost of a multipollutant control, such as option 3 (routing to a combustion device), is reasonable. As explained in that section, we believe that both approaches are appropriate for assessing the reasonableness of the multipollutant controls considered in this action. Therefore, we propose to find the cost of control to be reasonable as long as it is such under either of these two approaches.

Under the single pollutant approach, we assign all costs to the reduction of one pollutant and zero to all other pollutants simultaneously reduced. For this approach, we would find the cost of control reasonable if it is reasonable for reducing one pollutant alone. As shown in the evaluation below, which assigns all the costs to methane reduction alone, and based on an annualized cost per compressor of $114,146 to install and operate a new combustion device for the processing, transmission and storage segments, we estimate the cost of control for reducing methane emissions from a wet seal centrifugal compressor to be $478 per ton for the processing segment, $767 per ton in the transmission segment and $1,028 per ton in the storage segment. The cost of the simultaneous VOC reduction is zero because all the costs have been attributed to methane reduction.[55] It is important to note that these costs are likely over-estimates for most because they assume that each compressor requires a new, individual control device, which is not the case in most instances. It is our general understanding that multiple compressors can and do get routed to one common control. The estimates also do not reflect situations where installation of a control is not required because one is already available for use on site.

For the reasons stated above, we believe that these estimates represent a conservative scenario and that the cost of this control (routing to a combustion control device) is lower in most instances.

We also evaluate the cost of methane reduction by assigning all costs to VOC and zero to methane reduction. In the 2012 NSPS rulemaking we already found the cost of this control to be reasonable for reducing VOC emissions from wet seal centrifugal compressors in the production segment. Therefore, the cost of methane reduction is reasonable for centrifugal compressors in the production segment if we assign all costs to VOC under the single pollutant approach.

Although we propose to find the cost of control to be reasonable because it is reasonable under the above approach, we also evaluate the cost of this control under the multipollutant approach.

Under the multipollutant approach, the costs are allocated based on the percentage reduction expected for each pollutant. Because option 3 reduces both methane and VOC by 95 percent, we attribute 50 percent of the costs to methane reduction and 50 percent of the cost to VOC reduction. Based on this formulation, the costs for methane reduction are half of the estimated costs under the first approach above and therefore we believe these costs are reasonable for the same reasons discussed above. For VOC, we estimate the multipollutant approach costs to be $13,853 per ton in the transmission segment and $18,553 per ton in the

[52] Estimated uncontrolled VOC emissions from a wet seal compressor in the processing segment is not included here because these emissions are already subject to subpart OOOO and are not included in this proposed rule.

[53] *IBID.*

[54] Estimated VOC emissions reductions from a wet seal compressor in the processing segment is not included here because these emissions are already subject to the NSPS are not included in this proposed rule.

[55] In 2012, we already found that the cost of this control to be reasonable for reducing VOC emissions from wet seal centrifugal compressors in the production segment. We are not reopening that decision in this action. Therefore, this cost finding is relevant only to VOC reduction from wet seal centrifugal compressors in the transmission and storage segments.

storage segment.[56] While these costs may seem high, as explained above, they are based on the assumption that a control device is required for each compressor, which is not the case in most instances. The estimates also do not reflect situations where installation of a control is not required because one is already available for use on site. For the reasons stated above, we believe the cost of VOC reduction with this control to be to lower than the above estimates in most instances. Because the operators of facilities in the transmission and storage segment typically do not own the gas they are handling, these costs do not account for gas savings in those segments. Although these reductions may not result in a direct financial benefit to the operator, we believe it is worthwhile to note that overall these standards save a non-renewable resource.

As discussed above in section VIII.A two additional approaches, based on new capital expenditures and annual revenues, for evaluating whether the costs are reasonable. For the capital expenditure analysis, we used the capital expenditures for 2012 for NAICS 4862 as reported in the U.S. Census data, which we believe is representative of the transmission and storage segment. The total capital costs for complying with the proposed standards for centrifugal compressors is 0.011 percent of the total capital expenditures, which we believe is reasonable. For the total revenue analysis, we used the revenues for 2012 for NAICS 486210, which we believe is representative of the transmission and storage segment. The total annualized costs for complying with the proposed standards is 0.001 percent of the total revenues, which we believe is reasonable.

For all types of affected facilities in the transmission and storage segment, the total capital costs for complying with the proposed standards is 0.24 percent of the total capital expenditures, which is well below the percentage capital increase that courts have previously upheld as reasonable as discussed in Section VIII.A.. Similarly, the total annualized costs for complying with the proposed standards is also very low, at 0.11 percent of the total revenues.

With this control option, there would be secondary air impacts from combustion. However we did not identify any nonair quality or energy impacts associated with this control technique.

In light of the above, we find that the BSER for reducing VOC emissions from wet seal centrifugal compressors in the transmission and storage segment and for reducing methane emissions from all wet seal centrifugal compressors in the oil and natural gas source category are the same, *i.e.*, to capture and route the emissions to a combustion control device. As discussed above, this option results in a 95 percent reduction of emissions for both methane and VOC.

The 2012 NSPS requires that VOC emissions from wet seal centrifugal compressors in the natural gas production segment be reduced by 95 percent, which similarly reflects the reduction that can be achieved by capturing and routing to a combustion control device. We are, therefore, proposing to extend the existing 95 percent VOC reduction standard to all other wet seal centrifugal compressors in the oil and natural gas source category (*i.e.*, natural gas transmission and storage segments). We are also proposing to require 95 percent reduction of methane emissions from all wet seal centrifugal compressors in the oil and natural gas source category. As in the 2012 NSPS, our proposal would allow dry seal systems and routing emissions to a process as alternatives to routing to a combustion device to meet the proposed 95 percent emission reduction standards. We hope that by such provisions, owners and operators would be encouraged to employ these effective emission control options where feasible. As described above, the proposed VOC and methane standards would be the same as the current VOC standards for wet seal centrifugal compressors in the NSPS.

C. Proposed Standards for Reciprocating Compressors

In the 2012 NSPS, we established VOC standards for reciprocating compressors in the production (located other than at well sites) and processing segments of the oil and natural gas source category. In this action, we are proposing VOC standards for the remaining reciprocating compressors in the source category that are not located at a well site. We are also proposing methane standards for all reciprocating compressors in the oil and natural gas source category except for those that are located at well sites.[57] Based on the analysis below, the proposed VOC and methane standards described above are the same as the reciprocating compressor standards currently in the NSPS.

Reciprocating compressors are used throughout the oil and natural gas industry and are a source of methane and VOC emissions. Emissions occur when natural gas leaks around the piston rod when pressurized natural gas is in the cylinder. The most significant volumes of gas loss and resulting fugitive methane and VOC emissions are associated with piston rod packing systems. Rod packing systems are used to maintain a tight seal around the piston rod, preventing the high pressure gas in the compressor cylinder from leaking, while allowing the rod to move freely. This leakage rate is dependent on a variety of factors, including physical size of the compressor piston rod, operating speed and operating pressure. Higher leak rates are a consequence of improper fit, misalignment of the packing parts and wear. We estimate that reciprocating compressors have emissions of 0.198 tpy methane and 0.055 tpy VOC in the production segment (well sites), 12.3 tpy methane and 3.42 tpy VOC in the production segment (other than located at well site), 23.3 tpy methane and 6.48 tpy VOC in the processing segment, 27.1 tpy methane and 0.75 tpy VOC in transmission segment, and 28.2 tpy methane and 0.78 tpy VOC in the storage segment.

In developing the 2012 NSPS, we examined two options to reduce VOC emissions from reciprocating compressors. One approach was based on routing emission to a combustion device, as is used with wet seal centrifugal compressors. The other option was based on regular replacement of piston rod packing. Upon reconsideration of the standards in 2014, we evaluated a third option, routing of emissions to a process through a closed vent system under negative pressure. Information since the 2012 NSPS development have not identified other control options for reciprocating compressors.

We rejected combustion as the BSER because, as detailed in the 2011 TSD, routing of emissions to a control device can cause positive back pressure on the packing, which can cause safety issues due to gas backing up in the distance piece area and engine crankcase in some designs. While considering the option of routing of emissions to a process through a closed vent system under negative pressure, we determined that the negative pressure requirement not only ensures that all the emissions are

[56] In the 2012 rulemaking, we already concluded that the cost of this control to be reasonable for reducing VOC emissions from wet seal centrifugal compressors in the production segment and set standards for such reduction. We are not reopening that decision here. Accordingly, we are not addressing VOC reduction in the production segment here.

[57] As discussed later in this section, the control cost for reciprocating compressors at well site is not reasonable.

conveyed to the process, it also avoids the issue of inducing back pressure on the rod packing and the resultant safety concerns. Although this option can be used in some circumstances, it cannot be applied in every installation. As a result, this option was not further considered for the determination of the BSER.

As noted above, the most significant volumes of gas loss are associated with piston rod packing systems. We found that under the best conditions, new packing systems properly installed on a smooth, well-aligned shaft can be expected to leak a minimum of 11.5 scfh of natural gas. We determined that regular rod packing replacement, when carried out approximately every three years, effectively controls emissions and helps prevent excessive rod wear and determined that the BSER is regular replacement of rod packing. The control measures discussed above also reduce methane emissions.

We are not aware of any other methods for controlling methane and VOC emissions from the rod packing of reciprocating compressors. We estimate that replacement of the compressor rod packing every 26,000 hours reduces methane emissions by 0.16 tpy in the production segment (well site) 6.84 tpy in the production segment (excluding the well site), 18.6 tpy in the processing segment, 21.7 tpy in the transmission segment, and 21.8 tpy in the storage segment. Likewise, replacement of rod packing is estimated to reduce VOC emissions by 0.6 tpy in the transmission and storage segments.[58] See the 2011 TSD and 2015 TSD for details of these calculations.

For the 2012 NSPS, we estimated the annual costs of replacing the rod packing to be $2,493 for the production segment (well sites), $1,669 for the production segment (excluding well sites), $1,413 for processing plants, $1,748 for transmission stations, and $2,077 for storage facilities without considering the cost savings realized from the recovered gas. Considering gas savings, the annual cost of replacing the rod packing was $2,457 for the production segment (well sites), $83 for the production segment and a net savings for the processing segment. We did not consider gas savings for transmission and storage segments because owners and operators of these facilities do not necessarily own the gas they are handling and therefore would not realize gas savings.

As explained in section VIII.A, for purposes of this action, we have identified two approaches for evaluating whether the cost of a multipollutant control, such as rod packing replacement described above, is reasonable. As explained in that section, we believe that both approaches are appropriate for assessing the reasonableness of the multipollutant controls considered in this action. Therefore, we propose to find the cost of control to be reasonable as long as it is such under either of these two approaches.

Under the single pollutant approach, which attributes all cost to one pollutant and zero to the other pollutant, we would find the cost of control reasonable if it is reasonable for reducing one pollutant alone. When assigning all costs to methane alone and zero to the simultaneous VOC reduction, the cost of control is $15,802 per ton for the production segment (well sites), $244 per ton of methane for the production segment (excluding well sites), $76 per ton of methane for the processing segment, $81 per ton of methane in the transmission segment and $95 per ton of methane in the storage segment. When assigning all costs to VOC alone and zero to the simultaneous methane reduction, the cost of control under this approach is $2,910 per ton of VOC reduced in the transmission segment, and $3,434 per ton of VOC reduced in the storage segment.[59] In light of the above, we find the costs of rod-packing replacement are reasonable for reducing methane and VOC emissions across the industry (except at well sites) under the single pollutant approach irrespective of which pollutant bears all of the costs.

Under the multipollutant approach, because the control achieves the same reduction for both methane and VOC, we would apportion the cost equally between methane and VOC. Rod Packing replacement reduces the amount of natural gas emitted by the compressor. This natural gas contains both methane and VOC; therefore, reducing the amount of natural gas emitted will reduce methane and VOC in equal proportion. Using the multipollutant approach, the cost of control for methane is $7,901 per ton for the production segment (well sites), $122 per ton for the production segment (excluding well sites), $38 per ton for the processing segment, $40 per ton for the transmission segment, and $48 per ton for the storage segment. The cost of control for VOC under the multipollutant approach is $1,455 per ton for the transmission segment and $1,717 per ton for the storage segment.[60] In light of the above, with the exception of compressors located at well sites, we consider the costs to be reasonable for the estimated methane reductions across the source category and the estimated VOC reductions for the currently unregulated compressors under both approaches. In the 2012 NSPS rulemaking, we found the cost of rod packing not reasonable for reducing VOC emissions from reciprocating compressors at well sites. This finding remains unchanged under the two cost approaches discussed in section VIII.A. We also found the cost of control for methane emissions to not be reasonable for the amount of methane emissions achieved under either approach.

As discussed in section VIII.A, we also identified two additional approaches, based on new capital expenditures and annual revenues, for evaluating whether the costs are reasonable. For the capital expenditure analysis, we used the capital expenditures for 2012 for NAICS 4862 as reported in the U.S. Census data, which we believe is representative of the transmission and storage segment. The total capital costs for complying with the proposed standards for reciprocating compressors is 0.022 percent of the capital expenditures, which is well below the percentage capital increase that courts have previously upheld as reasonable as discussed in Section VIII.A.. For the total revenue analysis, we used the revenues for 2012 for NAICS 486210, which we believe is representative of the transmission and storage segment. The total annualized cost for complying with the proposed standards is 0.003 percent of the total revenues, which is also very low.

For all types of affected facilities in the transmission and storage segment, the total capital cost for complying with the proposed standards is 0.24 percent of the capital expenditures, and the total annualized cost for complying with the proposed standards is also very low, at 0.11 percent of the total revenues.

We did not identify any nonair quality health or environmental impacts or energy impacts associated with replacement of rod packing and

[58] Estimated VOC emissions reductions from reciprocating compressors in the production segment (at well sites and other than well sites) and the processing segment are not included here because these emissions are already subject to the NSPS are not included in this proposed rule. Under the 2012 NSPS we found the cost of control for VOC emissions from reciprocating compressors at well sites to be unreasonable and final rule did not set standards for reciprocating compressors located at well sites.

[59] VOC emissions reductions from reciprocating compressors in the production segment (at well sites and other than well sites) and the processing segment are already subject to the 2012 NSPS. We are not reopening those standards in this action.

[60] See footnote 56.

therefore, no analyses was conducted. In light of the above, we propose that rod packing replacement is the BSER for reducing methane and VOC emissions from compressors in the oil and natural gas sector, with the exception of reciprocating compressors located at well sites. See the 2011 and 2015 TSDs, available in the docket, for detail on methodology used for emissions and cost of control estimation.

Because the VOC and methane emissions from reciprocating compressors are fugitive emissions that occur when natural gas leaks around the piston rod when pressurized natural gas is in the cylinder, it is technically infeasible capturing and routing emissions to a control device. Therefore, we are unable to set a numerical emission limit for reciprocating compressors. Pursuant to section 111(h), we are proposing an operation standard based on rod packing replacement. The proposed standards are the same as the current VOC standard in the NSPS for reciprocating compressors, which was also based on rod packing replacement. Specifically we propose to replace rod packing every 3 years of operation. However, to account for segments of the industry in which reciprocating compressors operate in pressurized mode for a fraction of the calendar year (ranging from approximately 68 percent up to approximately 90 percent), we determined that 26,000 hours of operation would be, on average, comparable to 3 years of continuous operation. As a result, we are proposing a work practice standard based on our determination that replacement of rod packing no later than after 26,000 hours of operation or after 36 calendar months represents the BSER. The owner or operator would be required to monitor the hours of operation beginning with the installation of the reciprocating compressor affected facility. Cumulative hours of operation would be reported each year in the facility's annual report. Once the hours of operation reached 26,000 hours, the owner or operator would be required to change the rod packing immediately, although unexpected shutdowns could be avoided by tracking hours of operation and planning for packing replacement at scheduled maintenance shutdowns before the hours of operation reached 26,000. Alternatively, owners and operators may replace rod packing every 36 months and would not be required to track operating hours of the compressor.

As with the current requirement for controlling VOC from these reciprocating compressors, we are allowing routing of emissions from the rod packing to a process through a closed vent system under negative pressure as an alternative to rod packing replacement. As mentioned above, it is our understanding that this technology can capture all emissions; however, it may not be applicable to every compressor installation and situation and, therefore, it would be within the operator's discretion to choose whichever option is most appropriate for the application and situation at hand.

Following the December 31, 2014, amendments to the NSPS, which added the alternative of routing of emissions from the rod packing to a process through a closed vent system under negative pressure, we received a petition for administrative reconsideration of the standard for reciprocating compressors.[61] The petitioner requested that EPA provide an additional alternative to the rod packing replacement intervals of 26,000 hours or 36 months. The alternative suggested by the petitioner would consist of monitoring of rod packing leakage to identify when the rate of rod packing leakage indicates that packing replacement is needed. We have requested additional information from the petitioner on the technical details of the petitioner's concept. As a result, we are unable at this time to evaluate the alternative suggested by the petitioner.

D. Proposed Standards for Pneumatic Controllers

In the 2012 NSPS, we established VOC standards for pneumatic controllers in the production and processing segments of the oil and natural gas source category. In this action, we are proposing VOC standards for the remaining pneumatic controllers in the source category. We are also proposing methane standards for all pneumatic controllers in the oil and natural gas source category. Based on the analysis below, the BSER for reducing the methane and VOC emissions from the pneumatic controllers described above are the same as the BSER for those that are currently subject to the VOC standards. Accordingly, the proposed VOC and methane standards described above are the same as the pneumatic controller standards currently in the NSPS.

Pneumatic controllers are automated instruments used for maintaining a process condition, such as liquid level, pressure, pressure differential and temperature that typically operate by using available high-pressure natural gas.

In these ''gas-driven'' pneumatic controllers, natural gas may be released with every valve movement or continuously from the valve control pilot. The rate at which this release occurs is referred to as the device bleed rate. Bleed rates are dependent on the design of the device. Similar designs will have similar steady-state rates when operated under similar conditions. Gas-driven pneumatic controllers are typically characterized as ''high-bleed'' or ''low-bleed,'' where a high-bleed device releases more than 6 scfh of gas. There are two basic designs: (1) continuous bleed devices (high or low-bleed) are used to modulate flow, liquid level or pressure, and gas is vented at a steady-state rate; and (2) intermittent devices perform quick control movements and only release gas when they open or close a valve or as they throttle the gas flow.[62]

Not all pneumatic controllers are gas driven. These ''non-gas driven'' pneumatic controllers use sources of power other than pressurized natural gas, such as compressed ''instrument'' air. Because these devices are not gas driven, they do not release natural gas (or methane or VOC emissions), but they do have energy impacts because electrical power is required to drive the instrument air compressor system.

As we explained for the 2012 NSPS, because manufacturers' technical specifications for pneumatic controllers are stated in terms of natural gas bleed rate rather than methane or VOC, we used natural gas as a surrogate for VOC. We evaluated the impact of a high-bleed pneumatic controller emission rate (37 scfh of natural gas for the production and processing segments and 18 scfh of natural gas for the transmission and storage segments) contrasted with the emission rate of a low-bleed unit (1.39 scfh of natural gas for the production and processing segments and 1.37 scfh of natural gas for the transmission and storage segment).[63] We determined per-controller high-bleed pneumatic controller methane emissions to be 6.91

[61] Letter from John P. Miguez, Founder and Sr. Partner, M-Squared Products & Services, Inc., to Gina McCarthy, EPA Administrator, Petition for Reconsideration, January 20, 2015.

[62] We did not address intermittent controllers in the 2012 NSPS, and we are not addressing them in this action. Intermittent controllers are inherently low emitting sources because they vent only when actuating and the total emissions are dependent on the applications in which they are used.

[63] Emission factors and emissions data for production and processing segments are from TSD for the 2011 proposed rule, available in the docket. Emission factors for transmission and storage are from Subpart W Continuous Bleed Controller Emission Factors (Table W-1A of 40 CFR Part 98, Subpart W). Available at *http://www.ecfr.gov/cgi-bin/text-idx?SID=dda4d1715e9926ee3517ac08e6258817&node=40:21.0.1.1.3.23&rgn=div6#ap40.21.98_1238.1.*

tpy in the production segment, 1 tpy in the processing segment and 3.01 tpy in the transmission and storage segment. We estimate high-bleed pneumatic controller emissions to be 0.08 tpy VOC in the transmission and storage segments.[64] In contrast, we estimate the per-controller low-bleed pneumatic controller methane emissions to be 0.26 tpy in the production segment, 1 tpy in the processing segment, and 0.23 tpy in the transmission and storage segments. We estimate the low-bleed pneumatic controller VOC emissions to be 0.006 tpy in the transmission and storage segment.

We are not aware of any add-on controls that are or can be used to reduce methane or VOC emissions from gas-driven pneumatic controllers. Therefore, the available control techniques for reducing methane and VOC emissions from pneumatic controllers are the same, which are: (1) use of a low-bleed controllers; or (2) use of non-gas driven controllers (i.e., instrument air systems). These are the same control options we previously identified in the 2012 NSPS for controlling VOC emissions from pneumatic controllers. We did not find other available control options from our white paper process or information review.

As in the 2012 NSPS, our current analysis indicates that in order to use an instrument air system, a constant reliable electrical supply would be required to run the compressors for the system. At sites without available electrical service sufficient to power an instrument air compressor, only gas driven pneumatic devices are technically feasible in all situations. Therefore, for the production and transmission and storage segments, where electrical service sufficient to power an instrument air system is likely unavailable, we evaluated only the option to use low-bleed controllers in place of high-bleed controllers.

During the development of the 2012 NSPS, we estimated methane emissions along with VOC emissions from pneumatic controllers. We estimated that for an average high-bleed pneumatic controller located in the production segment, the difference in emissions between a high-bleed controller and a low-bleed controller is 6.65 tpy methane.[65] We also estimated that replacing a natural gas-driven pneumatic controller in the processing segment with an instrument air system would reduce methane emissions by 1 tpy. Further, we estimate that the emission reductions of replacing a high-bleed with a low-bleed pneumatic controller in the transmission and storage segment would be 2.79 tpy of methane and 0.077 tpy of VOC per controller.

For purposes of this action, we have identified in section VIII.A two approaches for evaluating whether the cost of a multipollutant control, such as replacing a high-bleed controller with a low-bleed controller, is reasonable. As explained in that section, we believe that both the single and multipollutant approaches are appropriate for assessing the reasonableness of the multipollutant controls considered in this action. Therefore, we find the cost of control to be reasonable as long as it is such under either of these two approaches.

Under the single pollutant approach, we assign all costs to the reduction of one pollutant and zero to all other pollutants simultaneously reduced. For this approach, we would find the cost of control reasonable if it is reasonable for reducing one pollutant alone. The evaluation below for pneumatic controllers in the production, transmission and storage segments first assigns all the costs to methane reduction alone, and uses an incremental capital cost difference between a new high-bleed controller and a new low-bleed controller of $165 for the production segment and $227 for the transmission and storage segment, which results in cost of control of $24 for the production segment and $25 for the transmission and storage segment.

We estimate the cost of replacing high-bleed controllers with low-bleed controllers to be $4 per ton of methane reduced in the production segment and $9 per ton of methane reduced in the transmission and storage segment. We find these costs to be reasonable for the amount of methane reduction it can achieve. Also, because all the costs have been attributed to methane reduction, the cost of simultaneous VOC reduction is zero and therefore reasonable. We also evaluated the cost by attributing all the costs to VOC reduction and estimated the cost to be $13 per ton of VOC reduction in the production segment and $323 per ton of VOC reduction in the transmission and storage segment.[66] We also find these costs to be reasonable.

Although we propose to find the cost of control to be reasonable because it is reasonable under the above approach, we also evaluated the cost on this control under the multipollutant approach. Under this approach, the costs are allocated based on the percentage reduction expected for each pollutant. Because replacing a high-bleed controller with a low-bleed controller reduces the natural gas emitted by the controller, both methane and VOC are reduced equally, we attribute 50 percent of the costs to methane reduction and 50 percent of the costs to VOC reduction. Based on this formulation, the costs for methane and VOC reduction are half of the estimated costs under the first approach and are therefore reasonable.

We also identified in section VIII.A two additional approaches, based on new capital expenditures and annual revenues, for evaluating whether the costs are reasonable. For the capital expenditure analysis, we used the capital expenditures for 2012 for NAICS 4862 as reported in the U.S. Census data, which we believe is representative of the transmission and storage segment. The total capital cost for complying with the proposed standards for pneumatic controllers is 0.0022 percent of the total capital expenditures, which is well below the percentage capital increase that courts have previously upheld as reasonable as discussed in Section VIII.A.. For the total revenue analysis, we used the revenues for 2012 for NAICS 486210, which we believe is representative of the transmission and storage segment. The total annualized cost for complying with the proposed standards is 0.0001 percent of the total revenues, which is also very low.

For all types of affected facilities in the transmission and storage segment, the total capital costs for complying with the proposed standards is 0.24 percent of the total capital expenditures, and the total annualized costs for complying with the proposed standards is 0.11 percent of the total revenues, which is also very low.

With this option, we do not anticipate any secondary air impacts. We also did not identify any nonair quality or energy impacts associated with this control

[64] Estimated VOC emissions from pneumatic controllers in the production and processing segments are not included here because these emissions are already subject to the NSPS are not included in this proposed rule.

[65] We note that VOC emissions from pneumatic controllers in the production and processing segments are already subject to subpart 0000. We are not reopening those standards in this rulemaking.

[66] We note that during the 2012 NSPS rulemaking, we already determined the costs of VOC reduction from pneumatic controllers at the production and processing segments to be reasonable. Accordingly, under the single-pollutant approach, the costs would also be reasonable for methane reduction as well for those pneumatic controllers.

technique, therefore, these impacts were not analyzed.

In light of the above, we find that the BSER for reducing methane emissions from continuous bleed natural gas-driven pneumatic controllers in the production and transmission and storage segment and VOC emissions from the remaining unregulated pneumatic controllers (i.e., those in the transmission and storage segment) would be the installation of low-bleed pneumatic controllers. This is the same BSER we identified in the 2012 final rule for reducing VOC emissions from pneumatic controllers in the production and processing segments.

Accordingly, we are proposing a methane emission standard for continuous-bleed, natural gas-driven pneumatic controllers in the production and transmission and storage segment to be a natural gas bleed rate of less than or equal to 6 scfh. We are also proposing a VOC emissions standard for continuous-bleed, natural gas-driven pneumatic controllers in the transmission and storage segment to be a natural gas bleed rate of less than or equal to 6 scfh. As described above, the proposed methane and VOC standards would be the same as the current VOC standards for pneumatic controllers in the production segment in the NSPS.

It is important to note that these costs are most likely over-estimates because they do not take into account the cost savings that would result based on the value of natural gas saved. Therefore, the above cost estimated, which we have already found to be reasonable, represent a conservative scenario and that the cost of these controls are lower in most instances.

For the processing segment, which comprises pneumatic controllers at natural gas processing plants, we identified instrument air systems and replacement of high-bleed controllers with low-bleed controllers as control options for reducing methane emissions from pneumatic controllers.[67] These are the same options we identified for the 2012 rule to reduce VOC emissions from these pneumatic controllers. As described below, we first evaluated the cost of an instrument air system to reduce methane emissions. Since we found these costs to be reasonable (as discussed below), we did not evaluate the costs of replacing the high-bleed pneumatic controllers with low-bleed controllers because the replacement option would result in less methane emission reduction than the instrument air option.

The annual costs of the instrument air system per gas processing plant without considering the cost savings realized from the recovered gas are $11,090, and $7,676 when considering these savings. See the 2012 Supplemental TSD[68] for details of these calculations.

We evaluate the cost of using an instrument air system to reduce methane emissions from the pneumatic controllers at gas processing plants based on the two approaches identified earlier in this section for considering the cost of a multipollutant control (in this case the instrument air system). Under the single pollutant approach, which assigns all costs to the reduction of one pollutant and zero to all other pollutants simultaneously reduced, we would find the cost of control reasonable if it is reasonable for reducing one pollutant alone. In the 2012 NSPS rulemaking, we already determined that the cost of this control for reducing VOC emissions alone is reasonable for pneumatic controllers at gas processing plants (76 FR 52760). Having assigned all the cost to VOC, the cost of methane reduction would be zero and therefore clearly reasonable. If we assign all the cost to methane instead, it is $738 per ton without considering cost savings and $506 per ton considering cost savings. These costs do not appear excessive, nor do we have reason to believe that they are beyond what the industry can bear. In light of the above, we find the cost of reducing methane emissions from the pneumatic controllers at gas processing plants to be reasonable under the single pollutant approach.

The second approach is to evaluate the cost on a multipollutant basis, based on the percentage reduction expected of VOC and methane. We estimate that replacing high-bleed pneumatic controllers with a non-natural gas driven pneumatic controller (i.e., instrument air-powered) reduces methane emissions by 15 tpy and VOC emissions by 4.2 tpy at gas processing plants. Refer to the 2012 TSD for details of these calculations. Because the control achieves the same reduction for both methane and VOC, under this approach, we apportion the cost equally, resulting in a cost of control of $369 per ton of methane reduced without considering gas savings. Considering gas savings, the cost of control is $253 per ton of methane. These costs do not appear excessive, nor do we have reason to believe that they are beyond what the industry can bear.

With respect to the VOC control cost under this approach, as mentioned above, in the 2012 NSPS rulemaking, we already determined that the cost of this control for reducing VOC emissions alone is reasonable for pneumatic controllers at gas processing plants (76 FR 52760). The cost of VOC reduction under the multiple pollutant approach would be half of that cost and therefore clearly reasonable. In light of the above, we find the cost of reducing methane emissions from pneumatic controllers at gas processing plants to be reasonable as well under the multi-pollutant approach. As mentioned above, we did not identify any nonair quality or energy impacts associated with this control option, therefore no impacts were analyzed.

Based on the above considerations, we propose that pneumatic controllers powered by an instrument air system are the BSER for reducing methane emission from pneumatic controllers at gas processing plants. This is the same BSER we identified for reducing VOC emissions from pneumatic controllers at gas processing plants in the 2012 final rule.

For the reasons discussed above and in the TSD, we have determined that BSER for reducing methane emissions from pneumatic controllers in the processing segment to be instrument air-activated controllers which represent an emission rate of zero for methane. Accordingly, we are proposing a methane standard for pneumatic controllers in the processing segment to be a natural gas bleed rate of zero. This is the same as the VOC standard for these pneumatic controllers in the 2012 NSPS.

We have identified situations where high-bleed controllers are necessary due to functional requirements, such as positive actuation or rapid actuation. An example would be controllers used on large emergency shutdown valves on pipelines entering or exiting compression stations. The current NSPS takes this into account by exempting pneumatic controllers from meeting the applicable emission standards if compliance would pose a functional limitation due to their actuation response time or other operating characteristics. We propose to similarly exempt pneumatic controllers from meeting the proposed methane standard if compliance would pose a functional limitation due to their actuation response time or other operating characteristics.

[67] In the 2012 NSPS, EPA established VOC standards for pneumatic controllers at natural gas processing plants. We are not reopening up those standards in this proposed rule.

[68] Oil and Natural Gas Section: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution—Background Supplemental Technical Support Document for the Final New Source Performance Standards, USEPA, Office of Air Quality Planning and Standards, April 2012.

E. Proposed Standards for Pneumatic Pumps

In the 2012 NSPS, we did not establish standards for pneumatic pumps. Pneumatic pumps are devices that use gas pressure to drive a fluid by raising or reducing the pressure of the fluid by means of a positive displacement, a piston or set of rotating impellers. Gas powered pneumatic pumps are generally used at oil and natural gas production sites where electricity is not readily available and can be a significant source of methane and VOC emissions.[69] As discussed previously, in April 2014, the EPA published a white paper titled ''Oil and Natural Gas Sector Pneumatic Devices.'' The paper summarized the EPA's understanding of methane and VOC emissions from pneumatic pumps and also presented the EPA's understanding of mitigation techniques (practices and equipment) available to reduce these emissions, including the efficacy and cost of the technologies and the prevalence of use in the industry.

During our review of the public and peer review comments on the white paper and the Wyoming state rules, we identified different types of pneumatic pumps that are commonly used in the oil and natural gas sector. Wyoming is the only state of which we are aware that has air emission standards for pneumatic pumps. Pneumatic chemical and methanol injection pumps are generally used to pump fairly small volumes of chemicals or methanol into well-bores, surface equipment, and pipelines. Typically, these pumps include plunger pumps with a diaphragm or large piston on the gas end and a smaller piston on the liquid end to enable a high discharge pressure with a varied but much lower pneumatic supply gas pressure. They are typically used semi-continuously with some seasonal variation. Pneumatic diaphragm pumps are another type used widely in the oil and natural gas sector to move larger volumes of liquids per unit of time at lower discharge pressures than chemical and methanol injection pumps. The usage of these pumps is episodic including transferring bulk liquids such as motor oil, pumping out sumps, and circulation of heat trace medium at well sites in cold climates during winter months.

Emissions from pneumatic pumps occur when the gas used in the pump stroke is exhausted to enable liquid filling of the liquid chamber side of the diaphragm. Emissions are a function of the amount of fluid pumped, the pressure of the pneumatic supply gas, the number of pressure ratios between the pneumatic supply gas pressure and the fluid discharge pressure, and the mechanical inefficiency of the pump.

Based on emission factors obtained from an EPA/GRI report[70] we estimate emissions from natural gas-driven piston pumps (i.e., pneumatic chemical and methanol injection pumps) and diaphragm pumps in both the production and processing segments to be 2.48 scf natural gas per hour and 22.45 scf natural gas per hour respectively. Based on these emission rates, and using the gas composition developed during the 2012 NSPS for the production and processing segments (i.e., natural gas is 82.9 percent methane and VOC constitutes 0.27797 pounds of VOC per pound of methane), we estimate the baseline emissions from a natural gas-driven piston pump in either the production or processing segment to be 0.38 tpy of methane and 0.11 tpy of VOC, and a gas-driven diaphragm pump to be 3.46 tpy of methane and 0.96 tpy of VOC.

We estimate that emissions in the transmission and storage segment are 2.21 scf natural gas per hour for a pneumatic piston pump and 20.05 scf natural gas per hour for a diaphragm pump. Based on these emissions rates, and using the gas composition developed during the 2012 NSPS for the transmission and storage segment (i.e., natural gas is 92.8 percent methane and VOC constitutes 0.0277 pounds of VOC per pound of methane), we estimate the baseline emissions from a natural gas-driven piston pump to be 0.38 tpy of methane and 0.01 tpy of VOC, and a gas-driven diaphragm pump to be 3.46 tpy of methane and 0.10 tpy of VOC in the transmission and storage segment. These emission estimates are explained in detail in the TSD for this action available in the docket.

As discussed in the white paper, we identified several options for reducing methane and VOC emissions from natural gas-driven pumps: replace natural gas-driven pumps with instrument air pumps, replace natural gas-driven pumps with solar-powered direct current pumps (solar pumps), replace natural gas-driven pumps with electric pumps, and route natural gas-driven pump emissions to a control device. In some applications, chemical injection pumps can be retrofitted with instrument air to drive the pumps.[71] During our review of the Wyoming state rule covering pneumatic pumps, we identified an additional mitigation option for reducing emission from piston and diaphragm natural gas-driven pumps, which involves routing the gas to a process[72] or routing the gas to a combustor (often done as part of the storage vessel control system). As with the BSER for wet seal centrifugal compressors discussed earlier in this section, the emission reduction potential for this option is estimated at 95 percent based on the efficiencies of the capture system and the combustion device. No further control options were identified from our white paper process or information review.

Instrument air systems and electric pumps require a reliable, constant supply of electrical power. Because of their remote locations, well sites, gathering and boosting stations and potentially transmission stations and storage facilities may not necessarily have a constant, reliable electrical power supply. Therefore, we do not believe the use of instrument air systems and electric pumps are feasible at all facilities in the production and transmission and storage segments. However, we take comment on is the availability of a constant, reliable source of electrical power at facilities throughout the oil and natural gas source category.

Natural gas processing plants are known to have a constant and reliable source of electrical power. Therefore, instrument air systems are technically feasible at natural gas processing plants. Because pumps powered by instrument air systems release no natural gas, the methane and VOC emissions are reduced by 100 percent under this control option.

For natural gas processing plants, the potential emission reduction for the instrument air option is 3.46 tpy of methane and 0.96 tpy of VOC for each diaphragm pump, and 0.38 tpy of methane and 0.11 tpy of VOC for each piston pump replaced.

While solar pumps can be installed in certain situations, these pumps are not technically feasible in all situations for which piston pumps and diaphragm pumps are needed. Specifically, weather

[69] GRI/EPA, 1996d.

[70] EPA/GRI. Methane Emissions from the Natural Gas Industry, Volume 13: Chemical Injection Pumps. June 1996 (EPA–60/R –96– 80m), Sections 5.1—Diaphragm Pumps and 5.2—Piston Pumps.

[71] U.S. EPA, 2011b.

[72] Subpart OOOOa defines ''route to a process'' to mean that ''the emissions are conveyed via a closed vent system to any enclosed portion of a process where the emissions are predominantly recycled and/or consumed in the same manner as a material that fulfills the same function in the process and/or transformed by chemical reaction into materials that are not regulated materials and/or incorporated into a product; and/or recovered.''

conditions in certain areas can limit the effectiveness of solar pumps and the capacity of solar pumps is also limited, so they cannot be used in all situations where larger pumps are needed. Therefore, solar pumps are not universally feasible control option for the production and transmission and storage segments.

As a result, we further analyzed the remaining potential control option for the production and transmission and storage segments, which is routing of natural gas-driven pump emissions to a process (e.g., used as fuel for a combustion source) or control device. Assuming that emissions are routed through a closed vent system to a control device or process, we believe these control options achieve a 95 percent reduction in emissions of methane and VOC.

Based on a 95 percent reduction, we estimate the reduction in emissions in the production segment to be 0.36 tpy methane and 0.10 tpy VOC per piston pump and 3.29 tpy of methane and 0.91 tpy of VOC per diaphragm pump. In the transmission and storage segment, we estimate the reduction in emissions to be 0.36 tpy of methane and 0.01 tpy VOC per piston pump and 3.29 tpy of methane and 0.09 tpy of VOC per diaphragm pump.

For purposes of this action, we have identified in section VIII.A two approaches for evaluating whether the cost of a multipollutant control, such as routing emissions to a combustion device, is reasonable. As explained in that section, we believe that both approaches are appropriate for assessing the reasonableness of the multipollutant controls considered in this action. Therefore, we find the cost of control to be reasonable as long as it is such under either of these two approaches.

Under the single pollutant approach, we assign all costs to the reduction of one pollutant and zero to all other pollutants simultaneously reduced. For this approach, we would find the cost of control reasonable if it is reasonable for reducing one pollutant alone. In the evaluation below, we assign all the costs to methane reduction alone and then to VOC reduction alone. For installing a new control device in the production segment we estimate the cost of control for reducing methane emissions using a combustion device to be $60,602 per ton for piston pumps and $6,656 per ton for diaphragm pumps. The cost of control for reducing VOC emissions for the production segment is $218,017 per ton for piston pumps and $23,944 for diaphragm pumps. For both the transmission and storage segment we estimate the cost of control for reducing methane emissions using a new combustion device to be $60,602 per ton for piston pumps and $6,656 per ton for diaphragm pumps. The cost of control for reducing VOC emissions for both the transmission and storage segment is $2,187,805 per ton for piston pumps and $240,279 for diaphragm pumps. We do not consider these cost to be reasonable.

Under the multipollutant approach we attributed half the cost to the methane reduction and half to the VOC reduction. For the production segment, we estimate the cost of reducing methane emissions using a new combustion device for piston pumps to be $30,301 per ton and the cost of reducing VOC emissions to be $109,009 per ton. For diaphragm pumps, the cost of reducing methane emissions is $3,328 per ton and the cost of reducing VOC emissions is $11,972 per ton. For both the transmission and storage segment, we estimate the cost of reducing methane emissions for piston pumps to be $30,301 per ton and the cost of reducing VOC emissions to be $1,093,903 per ton. For diaphragm pumps, the cost of reducing methane emissions is $3,328 per ton and the cost of reducing VOC emissions is $120,140 per ton. We also do not consider these cost to be reasonable.

While the use of a new combustion device is not cost-effective, the costs appear reasonable when using an existing combustion control device that is already on site. For routing the emissions in the production segment to an existing combustion control device, under the single pollutant approach, if we assign all costs to reducing methane emissions and zero to VOC reduction, the cost is $789 per ton of methane reduced for piston pumps and $87 per ton of methane reduced for diaphragm pumps.[73] If we assign all costs to VOC reduction and zero to methane reduction, the cost of reducing VOC emissions using an existing combustion control device in the production segment is $2,840 for piston pumps and $312 for diaphragm pumps. For both the transmission and storage segment, if we assign all costs to methane reduction and zero to VOC reduction, the cost of reducing methane emissions is $789 per ton for piston pumps and $87 per ton for diaphragm pumps.[74] If we assign all costs to VOC reduction and zero to methane reduction, the cost of reducing VOC emissions in the transmission and storage segment is $28,501 for piston pumps and $3,130 for diaphragm pumps. As shown above, under the single pollutant approach (i.e., all costs are assigned to one pollutant and zero to the other), the costs are reasonable regardless of which pollutant bears all the costs, except for the piston pump at the transmission and storage segment if all costs are assigned to VOC. In that case, while the cost is high if it is all assigned to VOC reduction, the cost is reasonable when assigned to methane reduction.

We also evaluated the cost of control for routing emissions to an existing control device under the multipollutant approach. For the production segment, we estimate the cost of reducing methane emissions for piston pumps to be $395 per ton and the cost of reducing VOC emissions to be $1,420 per ton. For diaphragm pumps, the cost of reducing methane emissions is $43 per ton and the cost of reducing VOC emissions is $156 per ton. For both the transmission and storage segment, we estimate the cost of reducing methane emissions for piston pumps to be $395 per ton and the cost of reducing VOC emissions to be $14,250 per ton. For diaphragm pumps, the cost of reducing methane emissions is $43 per ton and the cost of reducing VOC emissions is $1,565 per ton. With respect to piston pumps at transmission and storage segments, we note that the control is cost-effective under the single pollutant approach.

We further evaluated the cost of control for routing the emissions to a process by installing a new VRU or utilizing an existing VRU and found these costs to be similar to the costs presented above for new and existing combustion devices, respectively. We determined that the cost of control for routing to a process is similar to the costs presented above for an existing combustion device (see the TSD for this action for details of this analysis).

The option of routing emissions to a control device would result in secondary impacts from combustion. However, we did not identify any nonair quality or energy impacts associated with this option.

For natural gas processing plants, we evaluated instrument air systems based on a 100 percent emissions reduction potential resulting in a natural gas emission rate of zero standard cubic feet per hour. We estimated the potential reduction in emissions to be 0.38 tpy of methane and 0.11 tpy of VOCs per piston pump and 3.46 tpy of methane and 0.96 tpy of VOC per diaphragm pump.

Because instrument air systems are known to be used at natural gas

[73] This is well below the amount we find reasonable for reducing fugitive methane emissions at well site (see Section VIII.G.1 below).

[74] This is well below the amount we find reasonable for reducing fugitive methane emissions at well site (see Section VIII.G.1 below).

processing plants, we evaluated this option based on the incremental additional cost of routing the natural gas-driven pumps to an existing instrument air system, assuming all natural gas processing plants currently use instrument air systems. We determined that the incremental cost would be the cost of aligning the capacity of the existing instrument air system to that needed after the addition of the pumps. We determined that the facility would likely either replace an existing compressor or add a compressor to address any needed additional capacity. Because we do not have data on the number and distribution of types of natural gas-driven pumps at a typical natural gas processing plant, we developed several model plant scenarios. We varied the size of the plant (i.e., the total number of natural gas-driven pumps) from small, consisting of 4 natural gas-driven pumps per plant to large, consisting of 100 natural gas-driven pumps per plant. We also, within the size of the plant, varied the distribution of the type of pumps using three distribution scenarios (i.e., 50 percent diaphragm and 50 percent piston, 25 percent diaphragm and 75 percent piston, and 75 percent diaphragm and 25 percent piston). For each model plant, we evaluated the cost of an appropriately sized compressor based on the required additional capacity needed by number and types of pumps. Details of this analysis are included in the TSD for this action.

Under the single pollutant approach, which assigns all costs to the reduction of one pollutant and zero to all other pollutants, the cost of control for the model plants ranges from $374 to $2,185 per ton of methane reduced when assigning all costs to alone to methane reduction, and ranges from $1,344 to $7,861 per ton of VOC reduced when assigning all the costs alone to VOC reduction.

Under the multipollutant approach, we assigned half the cost of control to the methane reduction and half the cost to the VOC reduction. The cost of control under the second approach for the model plants ranges from $187 to $1,093 per ton of methane reduced and $672 and $3,930 per ton of VOC reduced. We find the control to be cost-effective under either approach.

We also identified in section VIII.A two additional approaches, based on new capital expenditures and annual revenues, for evaluating whether the costs are reasonable. For the capital expenditure analysis, we used the capital expenditures for 2012 for NAICS 2111, 213111 and 213112 as reported in the U.S. Census data, which we believe are representative of the production segment. The total capital cost for complying with the proposed standards for pneumatic pumps is 0.02 percent of the total capital expenditures, which is well below the percentage capital increase that courts have previously upheld as reasonable as discussed in Section VIII. A.. For the total revenue analysis, we used the revenues for 2012 for NAICS 211111, 211112 and 213112, which we believe are representative of the production segment. The total annualized costs for complying with the proposed standards is 0.001 percent of the total revenues, which is also very low.

For all types of affected facilities in the production segment, the total capital costs for complying with the proposed standards is 0.16 percent of the capital expenditures, and the total annualized costs for complying with the proposed standards is 0.13 percent of the total revenues, which is also very low.

In light of the above, we find that the BSER for reducing methane and VOC emissions from natural gas-driven piston and diaphragm pumps in the production and transmission and storage segments to be the same, which is to route the emissions to an existing control device or route the emissions to a process. As discussed above, this option results in a 95 percent reduction of emissions for both methane and VOC.

We find that the BSER for reducing methane and VOC emissions from natural gas-driven piston and diaphragm pumps at gas processing plants is to use an instrument air system in place of natural gas to drive the pumps. This option results in a 100 percent reduction of emissions for both methane and VOC.

We are, therefore, proposing to require 95 percent methane and VOC control from all natural gas-driven pneumatic pumps in the production and transmission and storage segments. For gas processing plants, we are proposing to require 100 percent methane and VOC control from all pneumatic pumps.

As discussed above in this section, solar-powered, electrically-powered and air-driven pumps cannot be employed in all applications. However, we encourage operators to use other than natural gas-driven pneumatic pumps where their use is technically feasible. To incentivize the use of such alternatives, we propose that ''pneumatic pump affected facility'' be defined in § 60.5365(h) to include only natural gas-driven pumps. As a result, pumps which are driven by means other than natural gas would not be affected facilities subject to the pneumatic pump provisions of the proposed NSPS.

Public and peer review comments on the white paper noted that, in addition to piston injection pumps and diaphragm pumps, gas assist glycol dehydrator pumps are used to pump lean glycol through glycol dehydrator systems. The glycol dehydrator pumps tend to be more complex because they ''scavenge'' energy from the high pressure (rich) glycol flowing from the contactor to the regenerator to provide the bulk of the energy needed to pump the lean glycol into the contactor. These types of pumps are used continuously when the glycol dehydrator is in use. Emissions from gas assist pumps are a function of the lean glycol circulation rate, the pressure of the contactor, and the model of the pump. Commenters of the white paper indicate that the emissions profile of all three types of pumps are very different. Commenters note that data for the EPA/GRI report for gas assisted glycol pumps is calculated based on two assumptions of process conditions, water removal, and information from the pump manufacturer which result in significant limitations for the calculated emission factor derived in the report. Furthermore, commenters discuss the NEI have activity factors and emissions separated from the glycol process emissions for gas assist lean glycol pumps, however commenters believe that it is not clear whether the estimate is valid.[75] Our understanding is that emissions from glycol dehydrator pumps are not separately quantified because these emissions are released from the same stack as the rest of the emissions from the dehydrator system, which are regulated under the NESHAP at 40 CFR part 63 HH and HHH. It is also our understanding from commenters that replacing the natural gas in gas-assisted lean glycol pumps with instrument air is not feasible and would create significant safety concerns. Commenters state that the only option for these types of pumps are to replace them with electric motor driven pumps however, solar and battery systems large enough to power these types of pumps are not feasible. The EPA is requesting comment and additional information on the level of uncontrolled emissions from these pumps, how these pumps are vented through the dehydrator system, and the amount and characteristics of VOC and methane emissions from uncontrolled glycol dehydrators.

[75] June 13, 2014, API comments on EPA's white paper on oil and natural gas sector pneumatic devices.

F. Proposed Standards for Well Completions

For the 2012 NSPS and this action, we have identified two subcategories of hydraulically fractured wells: (1) Non-exploratory and non-delineation wells, also known as development wells; and (2) exploratory (also known as wildcat wells) and delineation wells. An exploratory well is the first well drilled to determine the presence of a producing reservoir and the well's commercial viability. A delineation well is a well drilled to determine the boundary of a field or producing reservoir. In the 2012 NSPS analysis, we determined that the emissions profile for subcategory 2 wells is the same as subcategory 1 wells as described above. In our review of white paper comments and other information for this action, we found no information that would indicate this conclusion is not still valid.

1. Proposed Standards for Hydraulically Fractured Non-Wildcat and Non-Delineation Wells (Subcategory 1 Wells)

In the 2012 NSPS, we established VOC standards for subcategory 1 hydraulically fractured gas well completions and recompletions in the oil and natural gas source category. In this action, we are proposing VOC standards for subcategory 1 oil well completions and recompletions and methane standards for all subcategory 1 well completions and recompletions in the oil and natural gas source category. Based on the analysis below, the proposed VOC and methane standards are the same as the gas well completion standards currently in the NSPS.

As explained in the 2012 NSPS, well completions with hydraulic fracturing are a significant source of VOC and methane emissions, which occur when natural gas and non-methane hydrocarbons are vented to the atmosphere during flowback of a hydraulically fractured well. Flowback emissions are short-term in nature and occur over a period of several days following fracturing or refracturing of a well. Well completions include multiple steps after the well bore hole has reached the target depth. These steps include inserting and cementing-in well casing, perforating the casing at one or more producing horizons, and often hydraulically fracturing one or more zones in the reservoir to stimulate production. Hydraulic fracturing is one technique for improving oil or gas production where the reservoir rock is fractured with very high pressure fluid, typically water emulsion with a proppant (generally sand) that ''props open'' the fractures after fluid pressure is reduced. Emissions are a result of the flowback of the fracture fluids and reservoir gas at high volume and velocity necessary to lift excess proppant and fluids to the surface. This multi-phase mixture is often directed to a surface impoundment or to vented tanks (''frac tanks''), where methane and VOC vapors escape to the atmosphere during the collection of water, sand and hydrocarbon liquids. For oil wells, as the fracture fluids are depleted, the flowback eventually contains more volume of crude oil from the formation.

Wells that are fractured generally have greater amounts of VOC and methane emissions than conventional wells because of the extended length of the flowback period required to purge the well of the fluids and sand that are associated with the fracturing operation. Along with the fluids and sand from the fracturing operation, the flowback period may also result in emissions of methane and VOC that would not occur in large quantities at wells that are not fractured.

There are a variety of factors that will determine the length of the flowback period and actual volume of emissions from a well completion such as the number of zones, depth, pressure of the reservoir, gas composition, etc. This variability means there will be variability in the emissions from well completions.

For the 2012 NSPS, we estimated that the emissions from an uncontrolled gas well completion were 155.5 ton of methane and 22.7 tons of VOC per completion event. We also evaluated oil well completions emissions for the 2012 NSPS; however, based on that evaluation, we found oil well completion emissions to be very low and, therefore, no standard was set for oil well completions.

For this action, we reviewed new emissions studies and information for oil well completions, as described in the 2014 white paper titled ''Oil and Natural Gas Sector Hydraulically Fractured Oil Well Completions and Associated Gas during Ongoing Production.'' [76] While there was a wide variation in the results of these studies and analyses, even in the lowest estimates the potential methane and VOC emissions from hydraulically fractured oil well completions were significant. This conclusion is consistent with the Federal Implementation Plan (FIP) for the Fort Berthold Indian Reservation (FBIR) (78 FR 17836), in which the EPA found that the emissions from oil well completions are significant. One difference identified in our review of comments from the 2014 white paper process was that the average duration of an oil well completion is on the lower end of the duration identified in our 2012 analysis, or 3 days. Therefore, for this action, based on our review of these estimates and the methodologies used and in consideration of these comments, we estimate the potential emissions from hydraulically fractured oil well completions to be 9.72 tons methane and 8.14 tons VOC per 3-day completion event. These estimates are explained in detail in the 2012 TSD and the TSD for this action which are both available in the docket.

For the 2012 NSPS, we evaluated three options for reducing methane and VOC emissions from hydraulically fractured well completions: RECs, combustion (*e.g.,* flaring), and the combination of REC with combustion. For this action, we reviewed public and peer comments on the white paper as well as state (*i.e.,* Colorado [77] and Wyoming [78]) and other federal regulations (*i.e.,* FBIR FIP). We found that the available control techniques for reducing methane and VOC emissions from well completion are the same, and they were the same as the control options we previously identified for controlling VOC emissions: use of a REC, combustion, and the combination of REC with combustion. We did not find any other available control options from our white paper process or information review.

RECs are performed by separating the flowback water, sand, hydrocarbon condensate and natural gas to reduce the portion of natural gas and VOC vented to the atmosphere, while maximizing recovery of salable natural gas and condensate and routing the salable gas to a sales line and routing the recovered condensate to a completion or storage vessel for collection. Equipment required to conduct RECs may include tankage (*e.g.,* ''frac tanks''), special gas-liquid-sand separator traps and gas dehydration.

Control by combustion is achieved through the use of a completion combustion device. Based on our review, we believe that traditional combustion control devices, (*i.e.,* flares

[76] Available at *http://www.epa.gov/airquality/oilandgas/2014papers/20140415completions.pdf.*

[77] Colorado Oil and Gas Conservation Commission (COGCC) 805 Series Rules (805.b.(3)A) at: *http://cogcc.state.co.us/* and the Colorado Code of Regulations at: *http://www.sos.state.co.us/CCR/Welcome.do.*

[78] WY BACT permitting guidance available at *http://deq.state.wy.us/aqd/Oil%20and%20Gas/September%202013%20FINAL_Oil%20and%20Gas%20Revision_UGRB.pdf.*

or enclosed combustion control devices), are infeasible for use on completion emissions because the flowback following hydraulic fracturing consists of liquids, gases and sand in a high-volume, multiphase slug flow.

We evaluated RECs, completion combustion devices and the combination of RECs with completion combustion devices in order to determine the BSER for subcategory 1 wells. See the 2012 TSD and the TSD for this action, available in the docket, for further details on this evaluation. Our evaluation indicates that REC alone provides for a 90 percent control of emissions where gas emitted from the well is of suitable quality to be routed to a gathering line. However, in some cases, the initial gas produced from the well does not meet quality specifications for entering gathering lines, and as a result, the gas must be either vented or combusted. Due to the potential for gas to be emitted, even during the use of a REC, we determined that the use of a REC alone, would not be the BSER for control of emissions from well completions. Our evaluation of REC combined with a completion combustion device indicated that this option resulted in a 95 percent control of both methane and VOC emissions. We believe this option maximizes gas recovery and minimizes venting to the atmosphere.

Under the last option, combustion, we determined that a completion combustion device would achieve a 95 percent reduction in both methane and VOC emissions. However, we determined that combustion alone would not represent the BSER for well completions because, although the emissions reduction would be equal to the REC and completion combustion device combination (*i.e.,* 95 percent control), the opportunity to realize gas recovery would be minimized and the generation of secondary combustion-related emissions would be increased.

Based on the 95 percent emission reduction of a REC combined with a combustion device, in the 2012 NSPS, the emission reductions for a hydraulically fractured gas well completion event were estimated to be 147.4 tons of methane per completion.[79] In this analysis, we estimate the emission reductions for a hydraulically fractured oil well completion event to be 9.23 tons of methane and 7.73 tons of VOC per completion based on a 3-day completion event.

Equipment costs associated with RECs will vary from well to well. Costs of performing REC are projected to be between $700 and $6,500 per day, varying based on if key pieces of equipment are readily available on site or temporarily brought on site. Based on the 2012 NSPS evaluation, the average cost of a REC combined with completion combustion device for a 7-day completion event was $33,327. Under our evaluation in this action, we estimate the cost for a REC combined with a completion combustion device for a 3-day completion event to be $17,183. However, in both cases, there are savings associated with the use of RECs because the gas recovered can be incorporated into the production stream and sold. With the consideration of gas savings, the cost of a REC combined with a completion combustion device for a 7-day completions event for a gas well was estimated to have a net savings. With the consideration of gas savings, the cost of a REC combined with a completion combustion device for a 3-day completions event for an oil well was estimated to be $13,586.

We determined that the completion combustion device option for well completions also reduces both methane and VOC emissions by 95 percent. Therefore, the emissions reductions would be the same as those cited above for the REC combined with a completion combustion device. The annual cost for a completion combustion device alone was estimated be $3,523 for the 2012 NSPS for gas wells and $3,723 under this action for oil wells.

For purposes of this action, we have identified in section VIII.A two approaches (single pollutant approach and multipollutant approach) for evaluating whether the cost of a multipollutant control is reasonable. As explained in that section, we believe that both approaches are appropriate for assessing the reasonableness of the multipollutant controls considered in this action. Therefore, we find the cost of control to be reasonable as long as it is such under either of these two approaches.

Under the single pollutant approach, we assign all costs to the reduction of one pollutant and zero to all other pollutants simultaneously reduced. For this approach, we would find the cost of control reasonable if it is reasonable for reducing one pollutant alone. As shown in the evaluation below, which assigns all the costs to methane reduction alone, and based on an average cost of $33,327 per completion event for a gas well,[80] a REC combined with a completion combustion device, would cost $226 per ton of methane reduced per gas well completion without cost savings.[81] As noted above, this option maximizes gas recovery and minimizes venting to the atmosphere. Thus, when the value of the natural gas recovered (approximately 1,609 Mcf of natural gas) is considered, there is a net savings realized for this option for a subcategory 1 gas well completion or recompletion. We find these costs to be reasonable for the amount of methane reduction it can achieve. Also, because all the costs have been attributed to methane reduction, the cost of the simultaneous VOC reduction is zero and therefore reasonable. Based on the $17,183 annual cost of a REC combined with a completion combustion device for a 3-day completion event for an oil well completion, with the cost attributed only to methane and zero cost attributed to VOC, the cost of control would be $1,861 per ton of methane reduced per oil well completion without considering cost savings attributable to recovery of natural gas. As noted above, this option maximizes gas recovery and minimizes venting to the atmosphere. Thus, when the value of the natural gas recovered (approximately 999 Mcf of natural gas) is considered, the cost of control would be $1,471 per ton of methane reduced. Under this approach, the cost of control with all cost attributed to VOC would be $2,222 per ton of VOC reduced without considering natural gas savings and $1,757 with savings realized from natural gas recovery. Although the cost of control for a 3-day completion event at an oil well is higher than the cost at a gas well, we believe that the emissions reductions collectively are significant to justify the cost. Furthermore, we believe that the industry can bear the cost and survive.

Under the multipollutant approach, we assign 50 percent of the cost to methane and 50 percent to VOC. The cost of a REC with completion combustion for a gas well under this approach would be $930 per ton of methane and $1,111 per ton of VOC reduced without considering natural gas savings. With consideration of natural gas savings, the cost of control is $736 per ton of methane and $879 per ton of VOC reduced. Based on this

[79] Emissions of VOC from hydraulically fractured subcategory 1 gas wells are subject to the current NSPS and are not included in this action.

[80] As was determined for the 2012 NSPS.

[81] In 2012 we already found that the cost of this control to be reasonable for reducing VOC emissions from subcategory 1 gas well completions and recompletions. We are not reopening that decision in this action. Therefore, this cost finding is relevant only to methane reduction from subcategory 1 hydraulically fractured gas well completions.

formulation, the costs for pollutant reduction are half of the estimated costs under the single pollutant approach above and therefore we believe these costs are not excessive for the same reasons discussed above.

Under the single pollutant approach, based on the $3,723 annual cost of a completion combustion device alone, with the cost attributed only to methane and zero attributed to VOC, the cost of control would be $403 per ton of methane reduced per oil well completion. Under this approach, the cost of control with cost attributed to VOC would be $481 per ton of VOC reduced. Under the multipollutant approach, we assign 50 percent of the cost to methane and 50 percent to VOC. The cost of control under this approach would be $202 per ton of methane and $241 per ton of VOC reduced. We think that these costs are reasonable.

See the TSD, available in the docket for this action, for a detailed description of the cost of control analysis.

We believe that the cost for both options, a REC combined with combustion and combustion alone, are reasonable, given the emission reduction that would be achieved. However, given that the reductions in emissions are equal between the two control options, the REC combined with combustion option provides a better environmental benefit with the recovery of natural gas and reduced secondary combustion-related emissions. Aside from the potential hazards (in some cases) associated with combustion devices, we did not identify any nonair environmental impacts, health or energy impacts associated with REC combined with combustion, therefore these impacts were not analyzed.

The use of a completion combustion device with this option would produce secondary impacts in the form of combustion-related emissions. We estimate that, for subcategory 1 oil wells completed using a combination of REC and combustion for the year 2020, the combustion control-related emissions would be approximately 26 tons of total hydrocarbons, 69 tons of carbon monoxide, 24,846 tons of carbon dioxide, and 13 tons of nitrogen oxides.[82] This is based on the assumption that 5 percent of the flowback gas is combusted for subcategory 1 oil wells (controlled with a REC combined with a completion combustion device).

We estimate that this option of control for subcategory 1 oil well completions, for the projected year 2020, will result in estimated emission reductions of 127,478 tons of methane and 106,750 tons of VOC. Thus, we believe that the benefit of the methane and VOC reductions far outweigh the secondary impacts of combustion emissions formation during use of the completion combustion operation. Further, should only combustion be considered for all oil well completions, including the subcategory 1 wells, the secondary impacts would be far greater than those shown above. Secondary impacts of combustion alone are presented in the discussion of subcategory 2 wells below in this section.

We also identified in section VIII.A two additional approaches, based on new capital expenditures and annual revenues, for evaluating whether the costs are reasonable. For the capital expenditure analysis, we used the capital expenditures for 2012 for NAICS 2111, 213111 and 213112 as reported in the U.S. Census data, which we believe are representative of the production segment. The total capital costs for complying with the proposed standards for subcategory 1 wells is 0.081 percent of the total capital expenditures, which is well below the percentage capital increase that courts have previously upheld as reasonable as discussed in Section VIII.A.. For the total revenue analysis, we used the revenues for 2012 for NAICS 211111, 211112 and 213112, which we believe are representative of the production segment. The total annualized costs for complying with the proposed standards is 0.033 percent of the total revenues, which is also very low.

For all types of affected facilities in the production segment, the total capital costs for complying with the proposed standards is 0.16 percent of the total capital expenditures, and the total annualized costs for complying with the proposed standards is 0.13 percent of the total revenues, which is also very low.

For the reasons stated above, we determine the BSER for subcategory 1 (developmental wells) is the combination of REC and the use of a completion combustion device. We considered setting a numerical performance standard; however, we determined that it is not feasible to prescribe or enforce a numerical performance standard in this case because the gas can be discharged at multiple locations along with water and sand in a multiphase slug flow during the flowback process and, therefore, may not always be emitted at the same specific location in the process or through one conveyance designed and constructed to emit or capture such pollutant. Therefore, pursuant to section 111(h)(2) of the CAA, we are proposing an operational standard for subcategory 1 wells that would require a combination of gas capture and recovery and completion combustion devices to minimize venting of gas and condensate vapors to the atmosphere, with provisions for venting in lieu of combustion for situations in which combustion would present safety hazards or for periods when the flowback gas is noncombustible.

For the purposes of these standards we have separated the flowback period into two stages, the ''initial flowback stage'' and the ''separation flowback stage.'' The initial flowback stage begins with the first flowback from the well following hydraulic fracturing or refracturing and is characterized by high volumetric flow water, containing sand, fracturing fluids and debris from the formation with very little gas being brought to the surface, usually in multiphase slug flow. Due to the high volume of the flowback and the small amounts of gas in the initial flowback, operation of a separator may be initially technically infeasible, and there may not be sufficient gas for combustion. During these conditions, the emissions cannot be controlled from the flowback. During this stage, liquids are collected and routed to completion vessels.

For the reasons explained above, during the initial flowback stage, we propose that the flowback be routed to a storage vessel or to a well completion vessel that can be a frac tank, a lined pit or any other vessel. The purpose of this requirement is to avoid having operators route the flowback to an unlined pit or onto the ground. During the initial flowback stage, there is no requirement for controlling emissions from the vessel, and any gas in the flowback during this stage may be vented. However, the operator must route the flowback to a separator unless it is technically infeasible for a separator to function. Conditions that could prevent proper operation of the separator include insufficient gas concentration, low pressure gas, and multiphase slug flow containing solids that could clog the separator. We stress that operators have the responsibility to direct the flowback to a separator as soon as conditions allow a separator to function and in accordance with the General Provision requirements to operate the affected facility in a manner consistent with good air pollution control practices for minimizing emissions.

The second stage is defined as the ''separation flowback stage.'' The point at which the separator can function

[82] Because the current NSPS requires control of gas well completions using this option, we do not include the secondary emissions for control of methane from gas well completions.

marks the beginning of the separation flowback stage. This stage is characterized by the separator operating with a gaseous phase and one or more liquid phases in the separator. The end of the separation flowback stage marks the end of the flowback period and is defined as the point at which the well is shut in and the flowback equipment is permanently disconnected from the well, or the startup of production. The end of the separation flowback stage (i.e., the end of flowback) is characterized by certain indicators. Permanent disconnection of the temporary equipment used during flowback can be an indicator of flowback having ended. For example, during flowback, skid-mounted choke manifolds are used to limit flowback and assist in directing the flow. Temporary lines laid on the ground from the wellhead to the choke manifold and to the flowback separators and frac tanks are connected with ''hammer unions'' which are pipe unions that are designed for ease of making temporary connections and are characterized by ''ears'' that allow the joint to be made up quickly by striking with a hammer. After flowback has subsided and the well has cleaned up sufficiently, the well is temporarily shut in to disconnect the temporary flowback equipment. We believe that when the operator permanently disconnects choke manifolds, temporary separators, sand traps and other equipment connected with temporary lines and hammer unions, it is a reliable indicator that flowback has ended and the well is ready for production. At that point, we believe that operators will remove these temporary equipment used during flowback to avoid incurring unnecessary charges for additional days the equipment remains onsite. The well could start production immediately or it could remain shut in until permanent equipment is installed.

During the separation flowback stage, the operator must route all salable quality natural gas from the separator to a gas flow line or collection system, re-inject the gas into the well or another well, use the gas as an on-site fuel source or use the gas for another useful purpose that a purchased fuel or raw material would serve. If, during the separation flowback stage, it is technically infeasible to route the recovered gas to a flow line or collection system, re-inject the gas or use the gas as fuel or for other useful purpose, the recovered gas must be combusted. No direct venting of recovered gas is allowed during the separation flowback stage except when combustion creates a fire or safety hazard or can damage tundra, permafrost or waterways. With regard to infeasibility of collecting the salable quality gas, we believe that owners and operators plan their operations to extract a target product and evaluate whether the appropriate infrastructure access is available to ensure their product has a viable path to market before completing a well. However, there may be cases in which, for reason(s) not within an operator's control, the well is completed and flowback occurs without a suitable flow line available. We are aware that this situation may be more common for wells that are primarily drilled to produce oil. In those instances, § 60.5375(a)(3) requires the combustion of the gas unless combustion poses an unsafe condition as described above. During the separation flowback stage, all liquids from the separator must be directed to a storage vessel or to a well completion vessel, routed to a collection system or be re-injected into the well or another well.

The proposed operational standard would be accompanied by requirements for documentation of the overall duration of the completion event, duration of recovery using REC, duration of combustion, duration of venting, and specific reasons for venting in lieu of combustion.

2. Proposed Standards for Hydraulically Fractured Exploratory and Delineation Wells (Subcategory 2 Wells)

In the 2012 NSPS, we established VOC standards for subcategory 2 hydraulically fractured exploratory and delineation gas well completions. In this action, we are proposing VOC standards for the hydraulically fractured exploratory and delineation oil well completions and we are also proposing methane standards for all hydraulically fractured exploratory and delineation well completions in the oil and natural gas source category. Based on the analysis below, the proposed VOC and methane standards described above are the same as the current standards for hydraulically fractured exploratory and delineation gas well completion standards currently in the NSPS.

As noted above, for the 2012 NSPS analysis, we determined that the emissions profile for subcategory 2 wells is the same as subcategory 1 wells as described above. In our review of white paper comment and other information for this action, we found no information that would indicated this conclusion is not still valid. Specifically, we determined the emissions from a hydraulically fractured oil well were 9.72 tons of methane and 8.14 tons of VOC per 3-day completion event.[83]

In our analysis for the 2012 NSPS, we determined that a REC is not an option for subcategory 2 wells because there is no infrastructure in place to get the recovered gas to market or further processing. Typically, these types of wells generally are not in proximity to existing gathering lines at the time the well is completed. Therefore, for these wells, the only potential control option identified (both under the 2012 NSPS and under this action) is combustion of gases using a completion combustion device, as described above. Also as explained above, because of the high-volume, multiphase slug flow nature of the flowback gas, water and sand, control by a traditional flare or other control devices, such as vapor recovery units, is infeasible, since these devices would be overcome by the erratic high-volume flow of liquids, which leaves combustion as the only available control system for subcategory 2 wells. As also discussed above, combustion can present a fire hazard or other undesirable impacts in some situations. In our review of white paper comment and other information for this action, we found no information that would indicate this conclusion is not still valid.

Based on the 95 percent emission reduction of a completion combustion device, the emission reductions for a subcategory 2 hydraulically fractured gas well completion or recompletion are estimated to be 147.4 tons of methane per completion event.[84] The emission reductions for a subcategory 2 hydraulically fractured oil well completion or recompletion event are estimated to be around 9.23 tons of methane and 7.73 tons of VOC per 3-day completion.

As noted above, for purposes of this action, we have identified in section VIII.A two approaches (single pollutant and multipollutant approaches) for evaluating whether the cost of a multipollutant control is reasonable. As explained in that section, we believe that both approaches are appropriate for assessing the reasonableness of the multipollutant controls considered in this action. Therefore, we find the cost of control to be reasonable as long as it is such under either of these two approaches.

Under the single pollutant approach, we assign all costs to the reduction of

[83] Emissions of VOC from hydraulically fractured subcategory 2 gas wells are subject to the current NSPS and are not included in this action.

[84] Emissions of VOC from hydraulically fractured subcategory 2 gas wells are subject to the current NSPS and are not included in this action.

one pollutant and zero to all other pollutants simultaneously reduced. For this approach, we would find the cost of control reasonable if it is reasonable for reducing one pollutant alone. As shown in the evaluation below, which assigns all the costs to methane reduction alone, based on an average annual cost of $3,723 per completion, the cost of control for a completion combustion device is estimated to be $24 per ton of methane for subcategory 2 gas well completion event. We find these costs to be reasonable for the amount of methane reduction it can achieve. Also, because all the costs have been attributed to methane reduction, the cost of the simultaneous VOC reduction is zero and therefore reasonable.[85] We estimate the cost of control for subcategory 2 oil wells to be $403 per ton of methane and $481 per ton of VOC per oil well completion. We consider these costs to be reasonable considering the level of emissions reductions.

We also evaluated the cost of this control under the multipollutant approach. Under this approach, the costs would be allocated based on the estimated percentage reduction expected for each pollutant. Because completion combustion devices reduces both methane and VOC by 95 percent, we attributed 50 percent of the costs to methane reduction and 50 percent of the cost to VOC reduction. The costs for methane reduction would be half of the estimated costs under the first approach above, for both gas and oil wells, which we have found to be reasonable. See the TSD, available in the docket for this action, for a detailed description of the cost of control analysis.

Aside from the potential hazards associated with use of a completion combustion device in some cases, we did not identify any nonair environmental impacts, health or energy impacts associated with completion combustion devices, therefore no analysis was completed. However, completion combustion devices would produce combustion-related air pollutants. For 870 subcategory 2 oil well completion[86] for the projected year 2020, we estimated that 66 tons of total hydrocarbons, 175 tons of carbon monoxide, 62,628 tons of carbon dioxide, 32 tons of nitrogen oxides and 1 ton of particulate matter would be produced as secondary emissions. This is based on the assumption that 95 percent of flowback gas is combusted by the combustion device. This control option is estimated to reduce emissions for the projected year 2020 by 135,516 tons of methane and 113,481 tons of VOC. Thus, we believe that the benefit of the methane and VOC reduction far outweighs the secondary impact of combustion-related pollutants as a result of completion combustion control.

We also identified in section VIII.A two additional approaches, based on new capital expenditures and annual revenues, for evaluating whether the costs are reasonable. For the capital expenditure analysis, we used the capital expenditures for 2012 for NAICS 2111, 213111 and 213112 as reported in the U.S. Census data, which we believe are representative of the production segment. The total capital cost for complying with the proposed standards for subcategory 2 wells is 0.002 percent of the capital expenditures, which is well below the percentage capital increase that courts have previously upheld as reasonable as discussed in Section VIII.A.. For the total revenue analysis, we used the revenues for 2012 for NAICS 211111, 211112 and 213112, which we believe are representative of the production segment. The total annualized cost for complying with the proposed standards is 0.001 percent of the total revenues, which is also very low.

For all types of affected facilities in the production segment, the total capital costs for complying with the proposed standards is 0.16 percent of the total capital expenditures, and the total annualized costs for complying with the proposed standards is 0.13 percent of the total revenues, which is also very low.

In light of the above, we propose to determine that the BSER for subcategory 2 wells would be use of a completion combustion device. As we explained above, the gas is discharged at multiple locations during flowback and is mixed with water and sand in multiphase slug flow and therefore we determined that it is not feasible to set a numerical performance standard.

Pursuant to CAA section 111(h)(2), we are proposing an operational standard for subcategory 2 well completions that would require minimization of venting of gas and hydrocarbon vapors during the completion operation through the use of a completion combustion device, with provisions for venting in lieu of combustion for situations in which combustion would present safety hazards or for periods when the flowback gas is noncombustible. The owners and operators of these wells also have a general duty to safely maximize resource recovery and minimize releases to the atmosphere during flowback and subsequent recovery.

As with subcategory 1 wells, for the purposes of these standards we have separated the flowback period into two stages, the ''initial flowback stage'' and the ''separation flowback stage.'' During the initial flowback stage, the requirements for the subcategory 2 wells would be the same as the subcategory 1 wells. The flowback must be routed to a storage vessel or to a well completion vessel that can be a frac tank, a lined pit or any other vessel. During the initial flowback stage, there is no requirement for controlling emissions from the vessel, and any gas in the flowback during this stage may be vented.

During the separation flowback stage, the operator must route all salable quality gas from the separator to a gas flow line or collection system, combust the gas, re-inject the gas into the well or another well, use the gas as an on-site fuel source or use the gas for another useful purpose that a purchased fuel or raw material would serve. No direct venting of recovered gas is allowed during the separation flowback stage except when combustion creates a fire or safety hazard or can damage tundra, permafrost or waterways. During the separation flowback stage, all liquids from the separator must be directed to a storage vessel or to a well completion vessel, routed to a collection system or re-injected into the well or another well.

Consistent with requirements for subcategory 1 wells, owners or operators of subcategory 2 wells would be required to document completions and provide justification for periods when gas was vented in lieu of combustion.

We estimate that these control options for these sources would reduce the total emissions from all hydraulically fractured and refractured oil well completions for the projected year 2020 by 135,516 tons of methane and 113,481 tons of VOC. Thus, we believe that the benefit of the methane and VOC reductions far outweigh the secondary impact of combustion emissions formation during use of the completion combustion operation.

Several public and peer reviewer comments on the white paper noted that these technologies are currently in regular use by industry to control oil well completion and recompletion

[85] In 2012 we already found that the cost of this control to be reasonable for reducing VOC emissions from hydraulically fractured subcategory 2 gas well completions. We are not reopening that decision in this action. Therefore, this cost finding is relevant only to methane from hydraulically fractured subcategory 2 gas well completions.

[86] Because subcategory 2 hydraulically fractured gas well completions are subject to the current NSPS, we do not consider secondary impacts for the destruction of methane under this action.

emissions.[87] In addition, these control technologies are the same as those required in the 2012 NSPS to control completion emissions from hydraulically fractured gas well completions.

The EPA is aware that oil wells cannot perform a REC if there is not sufficient well pressure or gas content during the well completion to operate the surface equipment required for a REC. In the 2012 NSPS the EPA did not require low pressure gas wells to perform REC, but operators were required to control those well completions using combustion.[88] We solicit comment on the types of oil wells that will not be capable of performing a REC or combusting completion emissions due to technical considerations such as low pressure or low gas content, or other physical characteristics such as location, well depth, length of hydraulic fracturing, or drilling direction (e.g., horizontal, vertical, directional).[89] Additionally, we solicit comment on all aspects of our proposal to regulate methane and VOC emissions from hydraulically fractured oil well completions.

As shown in the analyses presented above, the BSER for hydraulically fractured oil wells is the same as that for gas wells. Accordingly, we are proposing to apply the current requirements for hydraulically fractured gas well completions to hydraulically fractured oil well completions. It is logical that the BSER analyses would result in the same BSER determinations for hydraulically fractured gas and oil wells, because the available options for controlling emissions and their current use in the field are the same. Several public and peer reviewer comments on the white paper noted that the control technologies used for controlling emissions from hydraulically fractured oil well completions are the same as those used for completions of hydraulically fractured gas wells. The commenters further noted that in many cases it is difficult to distinguish gas wells from oil wells, because many wells produce both gas and oil. Consistent standards for completions of hydraulically fractured gas wells and completions of hydraulically fractured oil wells will remove the need for operators to distinguish a gas well completion from an oil well completion for the purposes of complying with subpart OOOO. This change will improve the implementation of the standards by providing greater certainty as to which well completions must comply with the standards.

We are requesting comment on excluding low production wells (i.e., those with an average daily production of 15 barrel equivalents or less)[90] from the standards for well completions. It is our understanding that low production wells have inherently low emissions from well completions and many are owned and operated by small businesses. We are concerned about the burden of the well completion requirement on small businesses, in particular where there is little emission reduction to be achieved. We recognize that identification of these wells prior to completion events is difficult. We believe that drilling of a low production well may be unintentional and may be infrequent, but production may nevertheless proceed due to economic reasons. We solicit comment and information on emissions associated with low production wells, characteristics of these wells and supporting information that would help owners/operators and enforcement personnel identify these wells prior to completion. In addition, we understand that a daily average of 15 barrel equivalents is representative of low production wells for some purposes, we solicit comment on the appropriateness of this threshold for applying the standards for well completions.

Further, we are proposing that wells with a gas-to-oil ratio (GOR) of less than 300 scf of gas per barrel of oil produced would not be affected facilities subject to the well completion provisions of the NSPS.[91] We solicit comment on whether a GOR of 300 is the appropriate applicability threshold, and if the GOR of nearby wells would be a reliable indicator in determining the GOR of a new or modified well. The reason for the proposed threshold GOR of 300 is that separators typically do not operate at a GOR less than 300, which is based on industry experience rather than a vetted technical specification for separator performance. Though, in theory, any amount of free gas could be separated from the liquid, the reality is that this is not practical given the design and operating parameters of separation units operating in the field.

We believe that having no threshold may create a significant burden for operators to control emissions for these wells with just a trace of gas. EIA data show that the number of ''oil only'' wells drilled from 2007–2012 was less than 20 percent.[92] The potential emission characteristic of oils with a GOR of 300 is relevant when deciding whether this is a reasonable threshold. Primarily, the concern is volatility. The threshold must be low enough that the oil produced is considered non-volatile. Non-volatile ''black oils'' (oil likely to not have gases or light hydrocarbons associated with it) are generally defined as having GOR values in the range of 200 to 900.[93] Therefore, oil wells with GORs less than 300 are at the lower end of this range, and will not likely have enough gas associated that it can be separated. Therefore, the EPA is proposing that the NSPS requirements for well completions do not apply to completions wells with hydraulic fracturing that have a GOR of less than 300 scf/barrel.

We are soliciting comment on whether the well completion provisions of the proposed rule can be implemented on the effective date of the rule in the event of potential shortage of REC equipment and, if not, how a phase in could be structured. We believe that there will be a sufficient supply of REC equipment available by the time the NSPS becomes effective. However, we request comment on whether sufficient supply of this equipment and personnel to operate it will be available to accommodate the increased number of RECs by the effective date of the NSPS. We also request specific estimates of how much time would be required to get enough equipment in operation to accommodate the full number of RECs performed annually. In the event that public comments indicate that available equipment would likely be insufficient to accommodate the increase in number of REC performed, we are considering phasing in requirements for well completions in the final rule. Such a phased in approach could be structured

[87] The EPA received six peer review comments and several submissions of technical information and data on this paper, available for review at *http://www.epa.gov/airquality/oilandgas/whitepapers.html*.

[88] Following publication of the 2012 NSPS, EPA received a joint petition for administrative reconsideration of the rule. The petitioners questioned the technical merits of the low pressure well definition and asserted that the public had not had an opportunity to comment on the definition. EPA re-proposed the definition of ''low pressure gas well,'' on March 23, 2015 (80 FR 15180), and took comment on IPAA's alternative definition. EPA has finalized this definition in a separate action.

[89] Many of these data are available in the DrillingInfo database. More information is available at: *http://info.drillinginfo.com*.

[90] For the purposes of this discussion, we define 'low production well' as a well with an average daily production of 15 barrel equivalents or less. This reflects the definition of a stripper well property in IRC 613A(c)(6)(E).

[91] On February 24, 2015, API submitted a comment to EPA stating that oil wells with GOR values less than 300 do not have sufficient gas to operate a separator. *http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2014-0831-0137*.

[92] *http://www.eia.gov/todayinenergy/detail.cfm?id=13571#*.

[93] *http://petrowiki.org/Oil_fluid_characteristics*.

to provide for control of the highest emitting wells first, with other wells being included at a later date. We solicit comment on whether GOR of the well and production level of the well should be bases for the phasing of requirements for RECs. We also solicit suggestions for other ways to address a potential short-term REC equipment shortage that may hinder operators' compliance with the proposed NSPS. Additionally, we solicit comment on what an appropriate threshold should be for low production wells.

Finally, we solicit comment on criteria that could help clarify availability of gathering lines. Availability of a gathering line is one consideration affecting feasibility of recovery of natural gas during completion of hydraulically fractured wells. There are several factors that can affect availability of a gathering line including, but not limited to, the capacity of an existing gathering line to accept additional throughput, the ability of owners and operators to obtain rights of way to cross properties, and the distance from the well to an existing gathering line. We are aware that some states require collection of gas if a gathering line is present within a specific distance from the well. For example, Montana allows gas from wells to be flared only in cases where the well is farther than one-half mile from a gas pipeline.[94] We solicit comment on whether distance from a gathering line is a valid criterion on which to base requirements for gas recovery and, if so, what would an appropriate distance for such a threshold. In addition, we solicit comment on any other factors that could be specified in the NSPS for requiring recovery of gas from well completions.

3. Use of a Separator During Flowback

For subcategory 1, subcategory 2 and low pressure gas wells, the current NSPS at § 60.5375(a) and (f) requires routing of flowback to a separator unless it is technically infeasible for a separator to function. The NSPS also provides in § 60.5375(f) that subcategory 2 and low pressure wells are required to control emissions through combustion using a completion combustion device (which can include a pit flare) rather than being required to perform a REC. It was our understanding that a separator could be used at some point during the flowback period of every well completion. Recent information indicates that some wells, because of certain characteristics of the reservoir, do not need to employ a separator. In those cases, we understand that operators direct the flowback to a pit and can combust gas contained in the flowback as it emerges from the pipe. At some point, after the well has flowed sufficiently to clean up the wellbore and the gas is of salable quality, production begins or the well is temporarily shut in. As a result of this new information, our initial understanding may not apply.

We solicit comment on (1) the role of the separator in well completions and whether a separator can be employed for every well completion; and (2) the appropriate relationship of the separator in the context of our requirements that cover a very broad spectrum of wells. We solicit further information that would help inform our consideration of this issue as we seek to ensure we have adequately established appropriate requirements for all well completions subject to the NSPS.

G. Proposed Standards for Fugitive Emissions From Well Sites and Compressor Stations

In April 2014, the EPA published the white paper titled ''Oil and Natural Gas Sector Leaks'' [95] which summarized the EPA's current understanding of fugitive emissions of methane and VOC at onshore oil and natural gas production, processing, and transmission and storage facilities. The white paper also outlined our understanding of the mitigation techniques (practices and technology) available to reduce these emissions along with the cost and effectiveness of these practices and technologies.

The detection of fugitive emissions from oil and natural gas well sites and compressor stations, which are comprised of compressors at natural gas transmission, storage, gathering and boosting stations, can be determined using several technologies. Historically, fugitive emissions were detected using sensory monitoring (*e.g.,* visual, olfactory or sound) or EPA Method 21 to determine if a leak exceeded a set threshold (*e.g.,* the leak concentration was greater than the leak definition for the component). As described in the white paper, we found that many fugitive emission surveys are now conducted using OGI in the oil and natural gas source category, a technology that provides a visible image of gas emissions or leaks to the atmosphere. The OGI instrument works by using spectral wavelength filtering and an array of infrared detectors to visualize the infrared absorption of hydrocarbons and other gaseous compounds. As the gas absorbs radiant energy at the same waveband that the filter transmits to the detector, the gas and motion of the gas is imaged. The OGI instrument can be used for monitoring a large array of components at a facility and is an effective means of detecting fugitive emissions when the technology is used appropriately.

Several studies in the white paper estimated that OGI can monitor 1,875–2,100 components per hour. In comparison, the average screening rate using a Method 21 instrument (*e.g.,* organic vapor analyzer, flame ionization detector, flow measurement devices) is roughly 700 components per day. However, the EPA's recent work with OGI instruments suggests these studies underestimate the amount of time necessary to thoroughly monitor components for fugitive emissions using OGI instruments. Even though the amount of time may be underestimated, we believe the use of OGI can reduce the amount of time necessary to conduct fugitive emissions monitoring since multiple fugitive emissions components can be surveyed simultaneously, thus reducing the cost of identifying fugitive emissions in upstream oil and natural gas facilities when compared to using a handheld TVA or OVA, which requires a manual screening of each fugitive emissions component.

1. Fugitive Emissions From Well Sites

Fugitive emissions may occur for many reasons at well sites such as when connection points are not fitted properly, thief hatches are not properly weighted or sealed or when seals and gaskets start to deteriorate. Changes in pressure or mechanical stresses can also cause fugitive emissions. Potential sources of fugitive emissions, fugitive emissions components, include agitator seals, connectors, pump diaphragms, flanges, instruments, meters, open-ended lines, pressure relief devices, pump seals, valves or open thief hatches or holes in storage vessels, pressure vessels, separators, heaters and meters. For purposes of this proposed rule, fugitive emissions do not include venting emissions from devices that vent as part of normal operations, such as gas-driven pneumatic controllers or gas-driven pneumatic pumps.

Based on our review of the public and peer review comments on the white paper and the Colorado and Wyoming state rules, we believe that there are two options for reducing methane and VOC fugitive emissions at well sites: (1) A

[94] Administrative Rules of Montana (ARM) Title 17 Chapter 8 Air Quality Subchapter 16—Emission Control Requirements for Oil and Gas Well Facilities Operating Prior to Issuance of a Montana Air Quality Permit. Emission Control Requirements, 17.8.1603 Available at: *http://www.deq.mt.gov/dir/legal/Chapters/Ch08-toc.mcpx.*

[95] Available at *http://www.epa.gov/airquality/oilandgas/2014papers/20140415leaks.pdf.*

fugitive emissions monitoring program based on individual component monitoring using EPA Method 21 for detection combined with repairs, or (2) a fugitive emissions monitoring program based on the use of OGI detection combined with repairs. Several public and peer reviewer comments on the white paper noted that these technologies are currently used by industry to reduce fugitive emissions from the production segment in the oil and natural gas industry.

Each of these control options are evaluated below based on varying the frequency of conducting the survey and fugitive emissions repair threshold (*e.g.,* the specified concentration when using Method 21 or visible identification of methane or VOC when an OGI instrument is used). For our analysis, we considered quarterly, semiannual and annual survey frequency. For Method 21 monitoring and repair, we considered 10,000 ppm, 2,500 ppm and 500 ppm fugitive repair thresholds. The leak definition concentrations for other NSPS referencing Method 21 range from 500–10,000 ppm. Therefore, we selected 500 ppm, 2,500 ppm and 10,000 ppm. For OGI, we considered visible emissions as the fugitive repair threshold (*i.e.,* emissions that can be seen using OGI instrumentation). EPA's recent work with OGI indicates that fugitive emissions at a concentration of 10,000 ppm are generally detectable using OGI instrumentation provided that the right operating conditions (*e.g.,* wind speed and background temperature) are present. Work is ongoing to determine the lowest concentration that can be reliably detected using OGI.[96]

In order to estimate fugitive methane and VOC emissions from well sites, we used fugitive emissions component counts from the GRI/EPA report[97] for natural gas production well sites, and fugitive emissions component counts from the GHG inventory and API for oil production well sites. The types of production equipment located at natural gas production well pads include: Gas wellheads, separators, meters/piping, heaters, and dehydrators. The types of oil well production equipment include: Oil well heads, separators, headers and heater/treaters. The types of fugitive emissions components that are associated with both oil and natural gas wells include but are not limited to: Valves, connectors, open-ended lines and valves (OEL), and pressure relief device (PRD). Fugitive emissions component counts for each piece of equipment in the gas production segment were calculated using the average fugitive emissions component counts in the Eastern U.S. and the Western U.S. from the EPA/GRI report. These data were used to develop a natural gas well site model plant. Fugitive emissions components counts for these equipment types in the oil production segment were obtained from an American Petroleum Institute (API) workbook.[98] These data were used to develop an oil production well site model plant.

Since we have emission factors for only a subset of the components which are possible sources for fugitive emissions, our emission estimates are believed to be lower than the emissions profile for the entire set of fugitive emissions components that would typically be found at a well site.

The fugitive emission factors from AP–42,[99] which provided a single source of total organic compounds (TOC) emission factors that include non-VOCs, such as methane and ethane, were used to estimate emissions and evaluate the cost of control of a fugitive emissions program for oil and natural gas production well sites. Using the AP–42 factors, the methane and VOC fugitive emissions from a natural gas well site are estimated to be 4.5 tpy and 1.3 tpy, respectively. For an oil production well site, the estimated fugitive methane and VOC emissions are 1.1 tpy and 0.3 tpy, respectively. The calculation of these emission estimates are explained in detail in the background TSD for this proposal available in the docket.

Information in the white paper related to the potential emission reductions from the implementation of an OGI monitoring program varied from 40 to 99 percent. The causes for this range in reduction efficiency were the frequency of monitoring surveys performed and different assumptions made by the study authors. According to the calculations, which are based on uncontrolled emission factors for well pads contained within the EPA Oil and Natural Gas Sector Technical Support Document (2011), the Colorado Air Quality Control Commission, *Initial Economic Impact Analysis for Proposed Revisions to Regulation Number 7 (5 CCR 1001–9)* and the *FINAL ECONOMIC IMPACT ANALYSIS For Industry's Proposed Revisions to Colorado Air Quality Control Commission Regulation Number 3, 6, and 7 (5 CCR 1001–9)* (January 30, 2014), a quarterly monitoring program in combination with a repair program can reasonably be expected to reduce fugitive methane and VOC emissions at well sites by 80 percent. Although information in the white paper indicated emission reductions as high as 99 percent may be achievable with OGI, we do not believe such levels can be consistently achieved for all of types of components that may be subject to a fugitive emissions monitoring program. Therefore, using engineering judgement and experience obtained through our existing programs for finding and repairing leaking components, we selected 80 percent as an emission reduction level that can reasonably be expected to be achieved with a quarterly monitoring program. Due to the increased amount of time between each monitoring survey and subsequent repair, we believe that the level of emissions reduction achieved by less frequent monitoring surveys will be reduced from this level. Therefore, we assigned an emission reduction of 60 percent to semiannual monitoring survey and repair frequency and 40 percent to annual frequency, consistent with the reduction levels used by the Colorado Air Quality Control Commission in their initial and final economic impacts analyses. We solicit comment on the appropriateness of the percentage of emission reduction level that can be reasonably expected to be achieved with quarterly, semiannual, and annual monitoring program frequencies.

For Method 21, we estimated emissions reductions using The EPA Equipment Leaks Protocol document, which provides emissions factor data based on leak definition and monitoring frequencies primarily for the Synthetic Organic Chemical Manufacturing Industry (SOCMI) and Petroleum Refining Industry along with the emissions rates contained within the Technology Review for Equipment Leaks document.[100] We used these data along with the monitoring frequency (*e.g.,* annual, semiannual, and quarterly) at fugitive repair thresholds at 500, 2,500 and 10,000 ppm to determine uncontrolled emissions. Using this information we calculated an expected

[96] Draft Technical Support Document Appendices, Optical Gas Imaging Protocol (40 CFR part 60, Appendix K), August 11, 2015.

[97] Gas Research Institute/U.S. Environmental Protection Agency, Research and Development, Methane Emission Factors from the Natural Gas Industry, Volume 8, Equipment Leaks, June 1996 (EPA–600/R–96–080h).

[98] API Workbook 4638, 1996.

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

[100] Memorandum to Jodi Howard, EPA/OAQPS from Cindy Hancy, RTI International, Analysis of Emission Reduction Techniques for Equipment Leaks, December 21, 2011. EPA–HQ–OAR–2002–0037–0180.

emissions reduction percentage for each of the combinations of monitoring frequency and repair threshold.

We also looked at the costs of a monitoring and repair program under various monitoring frequencies and repair thresholds (for Method 21), including the cost of OGI monitoring survey, repair, monitoring plan development, and the cost-effectiveness of the various options.[101] For purposes of this action, we have identified in section VIII.A two approaches (single and multipollutant approaches) for evaluating the cost-effectiveness of a multipollutant control, such as the fugitive emissions monitoring and repair programs identified above for reducing both methane and VOC emissions. As explained in that section, we believe that both the single and multipollutant approaches are appropriate for assessing the reasonableness of the multipollutant controls considered in this action. Therefore, we find the cost of control to be warranted as long as it is such under either of these two approaches.

Under the first approach (single pollutant approach), we assign all costs to the reduction of one pollutant and zero to all other pollutants simultaneously reduced. Under the second approach (multipollutant approach), we allocate the annualized cost across the pollutant reductions addressed by the control option in proportion to the relative percentage reduction of each pollutant controlled. In the multipollutant approach, since methane and VOC emissions are controlled proportionally equal, half the cost is apportioned to the methane emission reductions and half the cost is apportioned to the VOC emission reductions. In this evaluation, we evaluated both approaches across the range of identified monitoring survey options: OGI monitoring and repair performed quarterly, semiannually and annually; and Method 21 performed quarterly, semiannually and annually, with a fugitive emissions repair threshold of 500, 2,500 and 10,000 ppm at each frequency. The calculation of the costs, emission reductions, and cost of control for each option are explained in detail in the TSD. As shown in the TSD, while the costs for repairing components that are found to have fugitive emissions during a fugitive monitoring survey remain the same, the annual repair costs will differ based on monitoring frequency.

As shown in our TSD, both OGI and Method 21 monitoring survey methodologies costs generally increase with increasing monitoring frequency (i.e., quarterly monitoring has a higher cost of control than annual monitoring). For EPA Method 21 specifically, the cost also increases with decreasing fugitive emissions repair threshold (i.e., 500 ppm results in a higher cost of control than 10,000 ppm). However, as shown in the TSD, the cost of control based on the OGI methodology for annual, semiannual, and quarterly monitoring frequencies for a model well site are estimated to be more cost-effective than Method 21 for those same monitoring frequencies.[102] We therefore focus our BSER analysis based on the use of OGI.

For the reasons stated below, we find that the control cost based on quarterly monitoring using OGI may not be cost-effective based on the information available. As shown in the TSD, under the single pollutant approach, if all costs are assigned to methane and zero to VOC reduction, the cost is $3,753 per ton of methane reduced, and $3,521 per ton if savings of the natural gas recovered is taken into account. If all costs are assigned to VOC and zero to methane reduction, the cost is $13,502 per ton of VOC reduced, and $12,668 per ton if savings of the natural gas recovered is taken into account. Under the multipollutant approach, the cost of control for VOC based on quarterly monitoring is $6,751 per ton, and $6,334 per ton of VOC reduced if savings are considered. In a previous NSPS rulemaking [72 FR 64864 (November 16, 2007)], we had concluded that a VOC control option was not cost-effective at a cost of $5,700 per ton. In light of the above, we find that the cost of monitoring/repair based on quarterly monitoring at well sites using OGI is not cost-effective for reducing VOC and methane emissions under either approach. Having found the control cost using OGI based on quarterly monitoring not to be cost-effective, we now evaluate the control cost based on annual and semi-annual monitoring using OGI. As shown in the TSD, the costs between annual and semi-annual monitoring are comparable. Because semi-annual monitoring achieves greater emissions reduction, we focus our analysis on the cost based on semi-annual monitoring.

While the cost appears high under the single pollutant approach, we find the costs to be reasonable under the multipollutant approach for the following reasons. As shown in the TSD, for VOC reduction, the cost is $4,979 per ton; when savings of the natural gas recovered are taken into account, the cost is reduced to $4,562 per ton. For methane reduction, the control cost is $1,384 per ton; when cost savings of the natural gas recovered is taken into account, the cost is reduced to $1,268 per ton. As explained above, we believe that we have underestimated the emissions from these well sites; therefore, we believe the use of OGI is more cost-effective than the amount presented here. Furthermore, while being used to survey fugitive components at a well site, the OGI may potentially help an owner and operator detect and repair other sources of visible emissions not covered by the NSPS. One example would be an intermittently acting pneumatic controller that is stuck open. The OGI could help the owner and operator detect and address and reduce such inadvertent emissions, resulting in more cost saving from more natural gas recovered.

We also identified in section VIII.A two additional approaches, based on new capital expenditures and annual revenues, for evaluating whether the costs are reasonable. For monitoring and repair of fugitive emissions at well sites, we believe that the total revenue analysis is more appropriate than the capital expenditure analysis and therefore we did not perform the capital expenditure analysis. For the total revenue analysis, we used the revenues for 2012 for NAICS 211111, 211112 and 213112, which we believe are representative of the production segment. The total annualized costs for complying with the proposed standards is 0.085 percent of the total revenues, which is very low.

For all types of affected facilities in the production, the total annualized costs for complying with the proposed standards is 0.13 percent of the total revenues, which is also very low.

For the reasons stated above, we find the cost of monitoring and repairing fugitive emissions at well sites based on semi-annual monitoring using OGI to be reasonable. To ensure that no fugitive emissions remain, a resurvey of the repaired components is necessary. We expect that most of the repair and resurveys are conducted at the same time as the initial monitoring survey while OGI personnel are still on-site. However, there may be some components that cannot not be repaired right away and in some instances not until after the initial OGI personnel are no longer on site. In that event, resurvey with OGI would require rehiring OGI personnel, which would make the resurvey not cost effective. On the other hand, as shown in TSD, the cost of conducting resurvey using Method 21 is $2 per component, which is reasonable.

[101] See pages 68–69 of the TSD.

[102] See the 2015 TSD for full comparison.

We did not find any nonair quality health and environmental impacts, or energy requirements associated with the use of OGI or Method 21 for monitoring, repairing and resurvey fugitive components at well sites. Based on the above analysis, we believe that the BSER for reducing fugitive methane and VOC emissions at well sites is a monitoring and repair standard based on semi-annual monitoring using OGI and resurvey using Method 21.

As mentioned above, OGI monitoring requires trained OGI personnel and OGI instruments. Many owners and operators, in particular small businesses, may not own OGI instruments or have staff who are trained and qualified to use such instruments; some may not have the capital to acquire the OGI instrument or provide training to their staff. While our cost analysis takes into account that owners and operators may need to hire contractors to perform the monitoring survey using OGI, we do not have information on the number of available contractors and OGI instruments. In light of our estimated 20,000 active wells in 2012 and that the number will increase annually, we are concerned that some owners and operators, in particular small businesses, may have difficulty securing the requisite OGI contractors and/or OGI instrumentation to perform monitoring surveys on a semi-annual basis. Larger companies, due to the economic clout they have by offering the contractors more work due to the higher number of wells they own, may preferentially retain the services of a large portion of the available contractors. This may result in small businesses experiencing a longer wait time to obtain contractor services. In light of the potential concern above, we are co-proposing monitoring survey on an annual basis at the same time soliciting comment and supporting information on the availability of trained OGI contractors and OGI instrumentation to help us evaluate whether owners and operators would have difficulty acquiring the necessary equipment and personnel to perform a semi-annual monitoring and, if so, whether annual monitoring would alleviate such problems.

Recognizing that additional data may be available, such as emissions from super emitters that may have higher emission factors than those considered in this analysis, we are also taking comment on requiring monitoring survey on a quarterly basis.

CAA section 111(h)(1) states that the Administrator may promulgate a work practice standard or other requirements, which reflects the best technological system of continuous emission reduction when it is not feasible to enforce an emission standard. CAA section 111(h)(2) defines the phrase ''not feasible to prescribe or enforce an emission standard'' as follows:

> [A]ny situation in which the Administrator determines that (A) a hazardous air pollutant or pollutants cannot be emitted through a conveyance designed and constructed to emit or capture such pollutant, or that any requirement for, or use of, such a conveyance would be inconsistent with any Federal, State, or local law, or (B) the application of measurement methodology to a particular class of sources is not practicable due to technological and economic limitations.

The work practice standards for fugitive emissions from well sites are consistent with CAA section 111(h)(1)(A), because no conveyance to capture fugitive emissions exist for fugitive emissions components at a well site. In addition, OGI does not measure the extent the fugitive emissions from fugitive emissions components. For the reasons stated above, pursuant to CAA section 111(h)(1)(b), we are proposing work practice standards for fugitive emissions from the collection of fugitive emission components at well sites.

The proposed work practice standards include details for development of a fugitive emissions monitoring plan, repair requirements and recordkeeping and reporting requirements. The fugitive emissions monitoring plan includes operating parameters to ensure consistent and effective operation for OGI such as procedures for determining the maximum viewing distance and wind speed during monitoring. The proposed standards would require a source of fugitive emissions to be repaired or replaced as soon as practicable, but no later than 15 calendar days after detection of the fugitive emissions. We have historically allowed 15 days for repair/resurvey in LDAR programs, which appears to be sufficient time. Further, in light of the number of components at a well site and the number that would need to be repaired, we believe that 15 days is also sufficient for conducting the required repairs under the proposed fugitive emission standards.[103] That said, we are also soliciting comment on whether 15 days is an appropriate amount of time for repair of sources of fugitive emissions at well sites.[104]

Many recent studies have shown a skewed distribution for emissions related to leaks, where a majority of emissions come from a minority of sources.[105] Commenters on the white papers agreed that emissions from equipment leaks exhibit a skewed distribution, and pointed to other examples of data sets in which the majority of fugitive methane and VOC emissions come from a minority of components (e.g., gross emitters). Based on this information, we solicit comment on whether the fugitive emissions monitoring program should be limited to ''gross emitters.''

We believe that a properly maintained facility would likely detect very little to no fugitive emissions at each monitoring survey, while a poorly maintained facility would continue to detect fugitive emissions. As shown in our TSD, we estimate the number of fugitive emission components at a well site to be around 700. We believe that a facility with proper operation would likely find one to three percent of components to have fugitive emissions. To encourage proper maintenance, we are proposing that the owner or operator may go to annual monitoring if the initial two consecutive semiannual monitoring surveys show that less than one percent of the collection of fugitive emissions components at the well site has fugitive emissions. For the same reason, we are proposing that the owner or operator conduct quarterly monitoring if the initial two semi-annual monitoring surveys show that more than three percent of the collection of fugitive emissions components at the well site has fugitive emissions. We believe the first year to be the tune-up year to allow owners and operators the opportunity to refine the requirements of their monitoring/repair plan. After that initial year, the required monitoring frequency would be annual if a monitoring survey shows less than one percent of components to have fugitive emissions; semi-annual if one to three percent of total components have fugitive emissions; and quarterly if over three percent of total components have fugitive emissions. We solicit comment on this approach, including the percentage used to adjust the monitoring frequency. We also solicit comment on the appropriateness of performance based monitoring frequencies. We also solicit comment on the appropriateness of triggering different monitoring frequencies based on the percentage of components with fugitive emissions. Under the proposed standards, the affected facility would be

[103] In our TSD we estimate the number of fugitive emissions components to be around 700 and of those components we estimate that about 1 percent would need to be repaired.

[104] This timelines is consistent with the timeline originally established in 1983 under 40 CFR part 60 subpart VV.

[105]

defined as the collection of fugitive emissions components at a well site. To clarify which components are subject to the fugitive emissions monitoring provisions, we propose to add a definition to § 60.5430 for ''fugitive emissions component'' as follows:

Fugitive emissions component means any component that has the potential to emit fugitive emissions of methane or VOC at a well site or compressor station site, including but not limited to valves, connectors, pressure relief devices, open-ended lines, access doors, flanges, closed vent systems, thief hatches or other openings on a storage vessels, agitator seals, distance pieces, crankcase vents, blowdown vents, pump seals or diaphragms, compressors, separators, pressure vessels, dehydrators, heaters, instruments, and meters. Devices that vent as part of normal operations, such as a natural gas-driven pneumatic controllers or natural gas-driven pumps, are not fugitive emissions components, insofar as the natural gas discharged from the device's vent is not considered a fugitive emission. Emissions originating from other than the vent, such as the seals around the bellows of a diaphragm pump would be considered fugitive emissions.

Thus, all fugitive emissions components at the affected facility would be monitored for fugitive emissions of methane and VOC.

For the reasons stated in section VII.G.1, for purposes of the proposed standards for fugitive emissions at well sites, modification of a well site is defined as when a new well is drilled or a well at the well site (where collection of fugitive emissions components are located) is hydraulically fractured or refractured. As explained in that section, other than these events, we are not aware of any other physical change to a well site that would result in an increase in emissions from the collection of fugitive components at such well site. To clarify and ease implementation, we propose to define ''modification'' to include only these two events for purposes of the fugitive emissions provisions at well sites.

In the 2012 NSPS, we provided that completion requirements do not apply to refracturing of an existing well that is completed responsibly (i.e. green completions). Building on the 2012 NSPS, the EPA intends to continue to encourage corporate-wide voluntary efforts to achieve emission reductions through responsible, transparent and verifiable actions that would obviate the need to meet obligations associated with NSPS applicability, as well as avoid creating disruption for operators following advanced responsible corporate practices. It has come to our attention that some owners and operators may already have in place, and are implementing, corporate-wide fugitive emissions monitoring and repair programs at their well sites that are equivalent to, or more stringent than our proposed standards. Such corporate efforts present the potential to further the development of LDAR technologies. To encourage companies to continue such good corporate policies and encourage advancement in the technology and practices, we solicit comment on criteria we can use to determine whether and under what conditions well sites operating under corporate fugitive monitoring programs can be deemed to be meeting the equivalent of the NSPS standards for well site fugitive emissions such that we can define those regimes as constituting alternative methods of compliance or otherwise provide appropriate regulatory streamlining. We also solicit comment on how to address enforceability of such alternative approaches (i.e., how to assure that these well sites are achieving, and will continue to achieve, equal or better emission reduction than our proposed standards). We recognize that meeting an NSPS performance level should not, standing alone, be a basis for a source not becoming an affected facility.

For the reasons stated above, we are also soliciting comments on criteria we can use to determine whether and under what conditions all new or modified well sites operating under corporate fugitive monitoring programs can be deemed to be meeting the equivalent of the NSPS standards for well sites fugitive emissions such that we can define those regimes as constituting alternative methods of compliance or otherwise provide appropriate regulatory streamlining. We also solicit comment on how to address enforceability of such alternative approaches (i.e., how to assure that these well sites are achieving, and will continue to achieve, equal or better emission reduction than our proposed standards).

We are requesting comment on whether the fugitive emissions requirements should apply to all fugitive emissions components at modified well sites or just to those components that are connected to the fractured, refractured or added well. For some modified well sites, the fractured or refractured or added well may only be connected to a subset of the fugitive emissions components on site. We are soliciting comment on whether the fugitive emission requirements should only apply to that subset. However, we are aware that the added complexity of distinguishing covered and non-covered sources may create difficulty in implementing these requirements. However, we note that it may be advantageous to the operator from an operational perspective to monitor all the components at a well site since the monitoring equipment is already onsite.

As explained above, Method 21 is not as cost-effective as OGI for monitoring. That said, there may be reasons why and owner and operator may prefer to use Method 21 over OGI. While we are confident with the ability of Method 21 to detect fugitive emissions and therefore consider it a viable alternative to OGI, we solicit comment on the appropriate fugitive emissions repair threshold for Method 21 monitoring surveys. As mentioned above, EPA's recent work with OGI indicates that fugitive emissions at a concentration of 10,000 ppm is generally detectable using OGI instrumentation provided that the right operating conditions (e.g., wind speed and background temperature) are present. Work is ongoing to determine the lowest concentration that can be reliably detected using OGI As mentioned above, we believe that OGI. In light of the above, we solicit comment on whether the fugitive emissions repair threshold for Method 21 monitoring surveys should be set at 10,000 ppm or whether a different threshold is more appropriate (including information to support such threshold).

While we did not identify OGI as the BSER for resurvey because of the potential cost associated with rehiring OGI personnel, there is no such additional cost for those who either own the OGI instrument or can perform repair/resurvey at the same time. Therefore, the proposed rule would allow the use either OGI or Method 21 for resurvey. When Method 21 is used to resurvey components, we are proposing that the component is repaired if the Method 21 instrument indicates a concentration less than 500 ppm above background. This has been historically used in other LDAR programs as an indicator of no detectable emissions.

The proposed standards would require that operators begin monitoring fugitive emissions components at a well site within 30 days of the initial startup of the first well completion for a new well or within 30 days of well site modification. We are proposing a 30 day period to allow owners and operators the opportunity to secure qualified contractors and equipment necessary for the initial monitoring survey. We are requesting comment on whether 30 days is an appropriate amount of time to begin conducting fugitive emissions monitoring.

We received new information indicating that some companies could experience logistical challenges with the availability of OGI instrumentation and qualified OGI technicians and operators to perform monitoring surveys and in some instances repairs. We solicit comment on both the availability of OGI instruments and the availability of qualified OGI technicians and operators to perform surveys and repairs.

We are proposing to exclude low production well sites (i.e., a low production site is defined by the average combined oil and natural gas production for the wells at the site being less than 15 barrels of oil equivalent (boe) per day averaged over the first 30 days of production) [106] from the standards for fugitives emissions from well sites. We believe the lower production associated with these wells would generally result in lower fugitive emissions. It is our understanding that fugitive emissions at low production well sites are inherently low and that such well sites are mostly owned and operated by small businesses. We are concerned about the burden of the fugitive emission requirement on small businesses, in particular where there is little emission reduction to be achieved. To more fully evaluate the exclusion, we solicit comment on the air emissions associated with low production wells, and the relationship between production and fugitive emissions. Specifically, we solicit comment on the relationship between production and fugitive emissions over time. While we have learned that a daily average of 15 barrel per day is representative of low production wells, we solicit comment on the appropriateness of this threshold for applying the standards for fugitive emission at well sites. Further, we solicit comment on whether EPA should include low production well sites for fugitive emissions and if these types of well sites are not excluded, should they have a less frequent monitoring requirement.

We are also requesting comment on whether there are well sites that have inherently low fugitive emissions, even when a new well is drilled or a well site is fractured or refractured and, if so, descriptions of such type(s) of well sites. The proposed standards are not intended to cover well sites with no fugitive emissions of methane or VOC. We are aware that some sites may have inherently low fugitive emissions due to the characteristics of the site, such as the gas to oil ratio of the wells or the specific types of equipment located on the well site. We solicit comment on these characteristics and data that would demonstrate that these sites have low methane and VOC fugitive emissions.

We are requesting comment on whether there are other fugitive emission detection technologies for fugitive emissions monitoring, since this is a field of emerging technology and major advances are expected in the near future. We are aware of several types of technologies that may be appropriate for fugitive emissions monitoring such as Geospatial Measurement of Air Pollutants using OTM–33 approaches (*e.g.,* Picarro Surveyor), passive sorbent tubes using EPA Methods 325A and B, active sensors, gas cloud imaging (*e.g.,* Rebellion photonics), and Airborne Differential Absorption Lidar (DIAL). Therefore, we are specifically requesting comments on details related to these and other technologies such as the detection capability; an equivalent fugitive emission repair threshold to what is required in the proposed rule for OGI; the frequency at which the fugitive emissions monitoring surveys should be performed and how this frequency ensures appropriate levels of fugitive emissions detection; whether the technology can be used as a stand-alone technique or whether it must be used in conjunction with a less frequent (and how frequent) OGI monitoring survey; the type of restrictions necessary for optimal use; and the information that is important for inclusion in a monitoring plan for these technologies.

2. Fugitive Emissions From Compressor Stations

Fugitive emissions at compressor stations in the oil and natural gas source category may occur for many reasons (*e.g.,* when connection points are not fitted properly, or when seals and gaskets start to deteriorate). Changes in pressure and mechanical stresses can also cause fugitive emissions. Potential sources of fugitive emissions include agitator seals, distance pieces, crank case vents, blowdown vents, connectors, pump seals or diaphragms, flanges, instruments, meters, open-ended lines, pressure relief devices, valves, open thief hatches or holes in storage vessels, and similar items on glycol dehydrators (*e.g.,* pumps, valves, and pressure relief devices). Equipment that vents as part of normal operations, such as gas driven pneumatic controllers, gas driven pneumatic pumps or the normal operation of blowdown vents are not considered to be sources of fugitive emissions.

Based on our review of the public and peer review comments on the white paper and the Colorado and Wyoming state rules, we believe that there are two options for reducing methane and VOC fugitive emissions at compressor stations: (1) A fugitive emissions monitoring program based on individual component monitoring using EPA Method 21 for detection combined with repairs, or (2) a fugitive emissions monitoring program based on the use of OGI detection combined with repairs. Several public and peer reviewer comments on the white paper noted that these technologies are currently used by industry to reduce fugitive emissions from the production segment in the oil and natural gas industry.

Each of these control options are evaluated below based on varying the frequency of conducting the monitoring survey and fugitive emissions repair threshold (*e.g.,* the specified concentration when using Method 21 or visible identification of methane or VOC when an OGI instrument is used). For our analysis, we considered quarterly, semiannual and annual monitoring frequencies. For Method 21, we considered 10,000 ppm, 2,500 ppm and 500 ppm fugitive repair thresholds. The leak definitions for other NSPS referencing Method 21 range from 500–10,000 ppm. Therefore, we selected 500 ppm, 2,500 ppm and 10,000 ppm. For OGI, we considered visible emissions as the fugitive repair threshold (*i.e.,* emissions that can be seen using OGI). EPA's recent work with OGI indicate that fugitive emissions at a concentration of 10,000 ppm are generally detectable using OGI instrumentation, provided that the right operating conditions (*e.g.,* wind speed and background temperature) are present. Work is ongoing to determine the lowest concentration that can be reliably detected using OGI.[107]

In order to estimate fugitive emissions from compressor stations, we used component counts from the GRI/EPA report [108] for each of the compressor station segments. Fugitive emission factors from AP–42 [109] were used to estimate emissions from gathering and boosting stations in the production

[106] For the purposes of this discussion, we define 'low production well' as a well with an average daily production of 15 barrel equivalents or less. This reflects the definition of a stripper well property in IRC 613A(c)(6)(E).

[107] Draft Technical Support Document Appendices, Optical Gas Imaging Protocol (40 CFR part 60, Appendix K), August 11, 2015.

[108] Gas Research Institute/U.S. Environmental Protection Agency, Research and Development, Methane Emission Factors from the Natural Gas Industry, Volume 8, Equipment Leaks, June 1996 (EPA–600/R–96–080h).

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

segment and emission factors from the GRI/EPA report were used to estimate fugitive emission from transmission and storage compressor stations and evaluate the cost of control for these segments.

Since we have emission factors for only a subset of the components which are possible sources for fugitive emissions, our emission estimates are believed to be lower than the emissions profile for the entire set of components that would typically be found at a compressor station.

The fugitive emission factors from AP–42,[110] which provided a single source of TOC emission factors that include non-VOCs, such as methane and ethane, were used to estimate emissions and evaluate the cost of control of a fugitive emissions program for compressor stations. Using the GRI/EPA and AP–42 data, fugitive emissions from gathering and boosting stations were estimated to be 35.1 tpy of methane and 9.8 tpy of VOC. Fugitive emissions from natural gas transmission stations were estimated to be 62.4 tpy of methane and 1.7 tpy of VOC. Fugitive emissions from natural gas storage facilities were estimated to be 164.4 tpy of methane and 4.6 tpy of VOC. The calculation of these emission estimates are explained in detail in the TSD available in the docket.

Information in the white paper related to the potential emission reductions from the implementation of an OGI monitoring program varied from 40 to 99 percent. The causes for this range in reduction efficiency were the frequency of monitoring surveys performed and different assumptions made by the study authors. According to the calculations, which are based on uncontrolled emission factors for well pads contained within the EPA Oil and Natural Gas Sector Technical Support Document (2011), the Colorado Air Quality Control Commission, *Initial Economic Impact Analysis for Proposed Revisions to Regulation Number 7 (5 CCR 1001–9) and the FINAL ECONOMIC IMPACT ANALYSIS For Industry's Proposed Revisions to Colorado Air Quality Control Commission Regulation Number 3, 6, and 7 (5 CCR 1001–9)* (January 30, 2014), a -quarterly monitoring program in combination with a repair program can reasonably be expected to reduce fugitive methane and VOC emissions at well sites by 80 percent. Although information in the white paper indicated emission reductions as high as 99 percent may be achievable with OGI, we do not believe such levels can be consistently achieved for all of types of components that may be subject to a fugitive emissions monitoring program. Therefore, using engineering judgement and experience obtained through our existing programs for finding and repairing leaking components, we selected 80 percent as an emission reduction level that can reasonably be expected to be achieved with a quarterly monitoring program. Due to the increased amount of time between each monitoring survey and subsequent repair, we believe that the level of emissions reduction achieved by less frequent monitoring surveys will be reduced from this level. Therefore, we assigned an emission reduction of 60 percent to semiannual monitoring survey and repair frequency and 40 percent to annual frequency, consistent with the reduction levels used by the Colorado Air Quality Control Commission in their initial and final economic impacts analyses. We solicit comment on the appropriateness of the percentage of emission reduction level that can be reasonably expected to be achieved with quarterly, semiannual, and annual monitoring program frequencies.

For Method 21, we estimated emissions reductions using The EPA Equipment Leaks Protocol document, which provides emissions factor data based on leak definition and monitoring frequencies primarily for the Synthetic Organic Chemical Manufacturing Industry (SOCMI) and Petroleum Refining Industry along with the emissions rates contained within the Technology Review for Equipment Leaks document.[111] We used these data along with the monitoring frequency (*e.g.*, annual, semiannual, and quarterly) at fugitive repair thresholds at 500, 2,500 and 10,000 ppm to determine uncontrolled emissions. Using this information we calculated an expected emissions reduction percentage for each of the combinations of monitoring frequency and repair threshold which range from.

We also looked at the costs of a monitoring and repair program under various monitoring frequencies and repair thresholds (for Method 21), including the cost of OGI monitoring survey, repair, monitoring plan development, and the cost-effectiveness of the various options.[112] For purposes of this action, we have identified in section VIII.A two approaches (single pollutant and multipollutant approaches) for evaluating whether the cost of a multipollutant control, such as the fugitive emissions monitoring and repair programs identified above, is reasonable. As explained in that section, we believe that both approaches are appropriate for assessing the reasonableness of the multipollutant controls considered in this action. Therefore, we find the cost of control to be reasonable as long as it is such under either of these two approaches.

Under the first approach (single pollutant approach), we assign all costs to the reduction of one pollutant and zero to all other pollutants simultaneously reduced. Under the second approach (multipollutant approach), we apportion the annualized cost across the pollutant reductions addressed by the control option in proportion to the relative percentage reduction of each pollutant controlled. In the multipollutant approach, since methane and VOC are controlled equally, half the cost is apportioned to the methane emission reductions and half the cost is apportioned to the VOC emission reductions. In this evaluation, we evaluated both approaches across the range of identified monitoring survey options: OGI monitoring and repair performed quarterly, semiannually and annually; and Method 21 monitoring performed quarterly, semiannually and annually, with a fugitive emissions repair threshold of 500, 2,500 and 10,000 ppm at each frequency. The calculation of the costs, emission reductions, and cost of control for each option are explained in detail in the TSD. As shown in the TSD, while the costs for repairing components that are found to have fugitive emissions during a fugitive monitoring survey remain the same, the annual repair costs will differ based on monitoring frequency.

As shown in our TSD, both OGI and Method 21 monitoring survey methodologies costs generally increase with increasing monitoring frequency (*i.e.*, quarterly monitoring has a higher cost of control than annual monitoring). For EPA Method 21 specifically, the cost also increases with decreasing fugitive emissions repair threshold (*i.e.*, 500 ppm results in a higher cost of control than 10,000 ppm). However, as shown in the TSD, the cost of control based on the OGI methodology for annual, semiannual, and quarterly monitoring frequencies are estimated to be more cost-effective than Method 21 for those same monitoring

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

[111] Memorandum to Jodi Howard, EPA/OAQPS from Cindy Hancy, RTI International, Analysis of Emission Reduction Techniques for Equipment Leaks, December 21, 2011. EPA–HQ–OAR–2002–0037–0180

[112] See pages 68–69 of the TSD.

frequencies.[113] We therefore focus our BSER analysis based on the use of OGI.

As shown in the TSD, the costs are comparable for all three monitoring frequencies using OGI. For the reasons explained below, we find the monitoring/repair program using OGI at compressor stations to be cost-effective for all three monitoring frequencies. Under the single pollutant approach, if we assign all control costs to VOC and zero to methane reduction, the costs range from $3,110 to $4,273 per ton of VOC reduced ($2,338 to $3,502 with gas saving) and zero for methane, which indicate that the control is cost-effective. Even if we assign all of the costs to methane and zero to VOC reduction, the costs, which range from $686 to $930 per ton of methane reduced ($471 to $715 per ton with gas savings), are well below our cost-effectiveness estimates for the semi-annual monitoring and repair option for reducing fugitive emissions at compressor stations, which we find to be reasonable for the reasons stated above. Under the multipollutant approach, the costs for VOC reduction range from $1,555 to $2,136 ($1,169 to $1,751 with gas saving). The costs for methane reduction range from $343 to $465 per ton ($236 to $358 per ton with gas savings). Again these cost estimates for methane reductions are well below our estimates for the monitoring/repair program at compressor stations using OGI based on semiannual monitoring, which we find to be reasonable for the reasons stated above. Further, as previously explained, we believe the emission reduction values used in these calculations underestimate the actual emission reductions that would be achieved by a fugitives monitoring and repair program, so these cost of control values likely represent a high end cost assumption. Therefore, we believe the use of OGI is more cost-effective than the amounts presented here. The calculation of the costs, emission reductions, and cost of control calculations for each option are explained in detail in the TSD for this action available in the docket.

While the costs are comparable for all three monitoring frequencies using OGI, for the reasons stated below, we have concerns with the potential compliance burdens, in particular on small businesses, associated with quarterly monitoring, and we believe that semi-annual monitoring could achieve meaningful reduction without such potential issues.

Further practical aspects we considered for the methodology of each monitoring survey include the likeliness that many owners and operators will hire a contractor to conduct the monitoring survey due to the cost of the specialized equipment needed to perform the monitoring survey and the training necessary to properly operate the OGI equipment. We also believe that small businesses are most likely to hire such contractors because they are less likely to have excess capital to purchase monitoring equipment and train operators. We are concerned that the limited supply of qualified contractors to perform monitoring surveys may lead to disadvantages for small businesses. Larger businesses, due to the economic clout they have by offering the contractors more work due to the higher number of compressor stations they own, may preferentially retain the services of a large portion of the available contractors. This may result in small businesses experiencing a longer wait time to obtain contractor services.

Specifically for conducting OGI monitoring surveys, we believe that many operators will hire OGI contractors to conduct the OGI surveys. The proposed fugitive emissions monitoring plan requires that operators verify the capability of OGI instrumentation, determine viewing distance, and determine the maximum wind speed. Additionally, there are specific requirements for conducting the survey such as how to operate OGI in adverse monitoring conditions or how to deal with interferences such as steam. Each corporate-wide plan will need to include these requirements and will require OGI contractors and operators to be trained to meet these requirement. The monitoring plan requirements will also cause the surveys to take more time, thus affecting the availability of OGI equipment and contractors. Therefore, if we specify quarterly monitoring surveys, we are concerned that the available supply of qualified contractors and OGI instruments may not be sufficient for small businesses to obtain timely monitoring surveys. For the reasons stated above, we have concerns with the potential compliance burdens, in particular on small businesses, associated with quarterly monitoring, and we believe that semi-annual monitoring could achieve meaningful reduction without such potential issues.

We also identified in section VIII.A two additional approaches, based on new capital expenditures and annual revenues, for evaluating whether the costs are reasonable. For monitoring and repair of fugitive emissions at compressor stations, we believe that the total revenue analysis is more appropriate than the capital expenditure analysis and therefore we did not perform the capital expenditure analysis. For the total revenue analysis, we used the revenues for 2012 for NAICS 486210, which we believe is representative of the production segment. The total annualized costs for complying with the proposed standards is 0.103 percent of the total revenues, which is very low.

For all types of affected facilities in the transmission and storage segment, the total annualized costs for complying with the proposed standards is 0.13 percent of the total revenues, which is also very low.

For the reasons stated above, we find the cost of monitoring and repairing fugitive emissions at compressor stations based on semi-annual monitoring using OGI to be reasonable. To ensure that no fugitive emissions remain, a resurvey of the repaired components is necessary. We expect that most of the repair and resurveys are conducted at the same time as the initial monitoring survey while OGI personnel are still on-site. However, there may be some components that cannot be repaired right away and in some instances not until after the initial OGI personnel are no longer on site. In that event, resurvey with OGI would require rehiring OGI personnel, which would make the resurvey not cost effective. On the other hand, as shown in the TSD, the cost of conducting a resurvey using Method 21 is $2 per component, which is reasonable.

We did not find any nonair quality health and environmental impacts, or energy requirements associated with the use of OGI or Method 21 for monitoring, repairing and resurveying fugitive emissions components at compressor stations. Based on the above analysis, we believe that the BSER for reducing fugitive methane and VOC emissions at compressor stations is a monitoring and repair standard based on semi-annual monitoring using OGI and resurvey using Method 21.

Although we identified OGI with semiannual monitoring as the BSER, we acknowledge that some states have promulgated rules that allow for annual monitoring of fugitive emission sources. In addition, EPA regulates GHGs in 40 CFR part 98 subpart W and requires annual fugitive emissions surveys for emissions reporting. As previously discussed we believe that we have underestimated our baseline fugitive emissions estimate for well sites and compressors and the emission reductions may be greater than we have estimated. However, because we continue to support efforts by states to

[113] See the 2015 TSD for full comparison.

establish fugitive emissions monitoring programs and to establish efficiencies across programs, we solicit comment on an alternate option for the fugitive emission monitoring program based on setting the initial monitoring frequency to an annual or quarterly frequency.

CAA section 111(h)(1) states that the Administrator may promulgate a work practice standard or other requirements, which reflects the best technological system of continuous emission reduction when it is not feasible to enforce an emission standard. CAA section 111(h)(2) defines the phrase ''not feasible to prescribe or enforce an emission standard'' as follows:

> [A]ny situation in which the Administrator determines that (A) a hazardous air pollutant or pollutants cannot be emitted through a conveyance designed and constructed to emit or capture such pollutant, or that any requirement for, or use of, such a conveyance would be inconsistent with any Federal, State, or local law, or (B) the application of measurement methodology to a particular class of sources is not practicable due to technological and economic limitations.

The work practice standards for fugitive emissions from compressor stations are consistent with CAA section 111(h)(1)(A), because no conveyance to capture fugitive emissions exist for fugitive emissions components. In addition, OGI does not measure the extent the fugitive emissions from fugitive emissions components. For the reasons stated above, pursuant to CAA section 111(h)(1)(b), we are proposing work practice standards for fugitive emissions from compressor stations.

The proposed work practice standards include details for development of a fugitive emissions monitoring plan, repair requirements and recordkeeping and reporting requirements. The fugitive emissions monitoring plan includes operating parameters to ensure consistent and effective operation for OGI such as procedures for determining the maximum viewing distance and wind speed during monitoring. The proposed standards would require a source of fugitive emissions to be repaired or replaced as soon as practicable, but no later than 15 calendar days after detection of the fugitive emissions. We have historically allowed 15 days for repair/resurvey in LDAR programs, which appears to be sufficient time. Further, in light of the number of components at a compressor station and the number that would need to be repaired, we believe that 15 days is also sufficient for conducting the required repairs under the proposed fugitive emission standards. That said, we are also soliciting comment on whether 15 days is an appropriate amount of time for repair of sources of fugitive emissions at compressor stations.[114]

Many recent studies have shown a skewed distribution for emissions related to leaks, where a majority of emissions come from a minority of sources.[115] Commenters on the white papers agreed that emissions from equipment leaks exhibit a skewed distribution, and pointed to other examples of data sets in which the majority of methane and VOC fugitive emissions come from a minority of components (*e.g.*, gross emitters). Based on this information, we solicit comment on whether the fugitive emissions monitoring program should be limited to ''gross emitters.''

We believe that a properly maintained facility would likely detect very little to no fugitive emissions at each monitoring survey, while a poorly maintained facility would continue to detect fugitive emissions. We believe that a facility with proper operation would likely find one to three percent of components to have fugitive emissions. To encourage proper maintenance, we are proposing that the owner or operator may go to annual monitoring if the initial two consecutive semiannual monitoring surveys show that less than one percent of the collection of fugitive emissions components at the compressor station has fugitive emissions. For the same reason, we are proposing that the owner or operator conduct quarterly monitoring if the initial two semi-annual monitoring surveys show that more than three percent of the collection of fugitive emissions components at the compressor station has fugitive emissions. We believe the first year to be the tune-up year to allow owners and operators the opportunity to refine the requirements of their monitoring/repair plan. After that initial year, the required monitoring frequency would be annual if a monitoring survey shows less than one percent of components to have fugitive emissions; semi-annual if one to three percent of total components have fugitive emissions; and quarterly if over three percent of total components have fugitive emissions. We solicit comment on this approach, including the percentage used to adjust the monitoring frequency. We also solicit comment on the appropriateness of performance based monitoring frequencies. We also solicit comment on the appropriateness of triggering different monitoring frequencies based on the percentage of components with fugitive emissions.

Under the proposed standards, the affected facility would be defined as the collection of fugitive emissions components at a compressor station. To clarify which components are subject to the fugitive emissions monitoring provisions, we propose to add a definition to § 60.5430 for ''fugitive emissions component'' as follows:

> Fugitive emissions component means any component that has the potential to emit fugitive emissions of methane or VOC at a well site or compressor station site, including but not limited to valves, connectors, pressure relief devices, open-ended lines, access doors, flanges, closed vent systems, thief hatches or other openings on a storage vessels, agitator seals, distance pieces, crankcase vents, blowdown vents, pump seals or diaphragms, compressors, separators, pressure vessels, dehydrators, heaters, instruments, and meters. Devices that vent as part of normal operations, such as a natural gas-driven pneumatic controller or a natural gas-driven pump, are not fugitive emissions components, insofar as the natural gas discharged from the device's vent is not considered a fugitive emission. Emissions originating from other than the vent, such as the seals around the bellows of a diaphragm pump, would be considered fugitive emissions.

Thus, all fugitive emissions components at the affected facility would be monitored for fugitive emissions of methane and VOC.

For the reasons stated in section VII.G.2, for purposes of the proposed standards for fugitive emission at compressor stations, we propose that a modification occurs only when a compressor is added to the compressor station or when physical change is made to an existing compressor at a compressor station that increases the compression capacity of the compressor station. As explained in that section, since fugitive emissions at compressor stations are from compressors and their associated piping, connections and other ancillary equipment, expansion of compression capacity at a compressor station, either through addition of a compressor or physical change to the an existing compressor, would result in an increase in emissions to the fugitive emissions components. Other than these events, we are not aware of any other physical change to a compressor station that would result in an increase in emissions from the collection of fugitive components at such compressor station. To provide clarity and ease of implementation, for the purposes of the proposed standards for fugitive emissions at compressor stations, we are proposing to define modification as the

[114] This timeline is consistent with the timeline originally established in 1983 under 40 CFR part 60 subpart VV.

[115] See 2015 TSD.

addition of a compressor at an existing compressor station or when a physical change is made to an existing compressor at a compressor station that increases the compression capacity of the compressor station.

To encourage broadly applied fugitive emissions monitoring, we are also soliciting comments on criteria we can use to determine whether and under what conditions all new or modified compressor stations operating under corporate fugitive monitoring programs can be deemed to be meeting the equivalent of the NSPS standards for compressor stations fugitive emissions such that we can define those regimes as constituting alternative methods of compliance or otherwise provide appropriate regulatory streamlining. We also solicit comment on how to address enforceability of such alternative approaches (*i.e.*, how to assure that these compressor stations are achieving, and will continue to achieve, equal or better emission reduction than our proposed standards).

We are requesting comment on whether the fugitive emissions requirements should apply to all of the fugitive emissions sources at the compressor station for modified compressor stations or just to fugitive sources that are connected to the added compressor. For some modified compressor stations, the added compressor may only be connected to a subset of the fugitive emissions sources on site. We are soliciting comment on whether the fugitive emission requirements should only apply to that subset. However, we are aware that the added complexity of distinguishing covered and non-covered sources may create difficulty in implementing these requirements. However, we note that it may be advantageous to the operator from an operational perspective to monitor all the components at a compressor station since the monitoring equipment is already onsite.

As explained above, Method 21 is not as cost-effective as OGI for monitoring. That said, there may be reasons why and owner and operator may prefer to use Method 21 over OGI. While we are confident with the ability of Method 21 to detect fugitive emissions and therefore consider it a viable alternative to OGI, we solicit comment on the appropriate fugitive emissions repair threshold for Method 21 monitoring surveys. As mentioned above, EPA's recent work with OGI indicates that fugitive emissions at a concentration of 10,000 ppm is generally detectable using OGI instrumentation provided that the right operating conditions (*e.g.*, wind speed and background temperature) are present. Work is ongoing to determine the lowest concentration that can be reliably detected using OGI As mentioned above, we believe that OGI. In light of the above, we solicit comment on whether the fugitive emissions repair threshold for Method 21 surveys should be set at 10,000 ppm or whether a different threshold is more appropriate (including information to support such threshold).

While we did not identify OGI as the BSER for resurvey because of the potential cost associated with rehiring OGI personnel, there is no such additional cost for those who either own the OGI instrument or can perform repair/resurvey at the same time. Therefore, the proposed rule would allow the use either OGI or Method 21 for resurvey. When Method 21 is used to resurvey components, we are proposing that the component is repaired if the Method 21 instrument indicates a concentration of less than 500 ppm above background. This has been historically used in other LDAR programs as an indicator of no detectable emissions.

The proposed standards would require that operators begin monitoring fugitive emissions components at compressor stations with 30 days of the initial startup of a new compressor station or within 30 days of a modification of a compressor station. We are proposing 30 day period to allow owners and operators the opportunity to secure qualified contractors and equipment necessary for the initial monitoring survey. We are requesting comment on whether 30 days is an appropriate amount of time to begin conducting fugitive emissions monitoring.

We received new information indicating that some companies could experience logistical challenges with the availability of OGI instrumentation and qualified OGI personnel to perform monitoring surveys and in some instances repairs. We solicit comment on both the availability of OGI instruments and the availability of qualified OGI personnel to perform monitoring surveys and repairs.

We are requesting comment on whether there are other fugitive emission detection technologies for fugitive emissions monitoring, since this is a field of emerging technology and major advances are expected in the near future. We are aware of several types of technologies that may be appropriate for fugitive emissions monitoring such as Geospatial Measurement of Air Pollutants using OTM–33 approaches (*e.g.,* Picarro Surveyor), passive sorbent tubes using EPA Methods 325A and B, active sensors, gas cloud imaging (*e.g.,* Rebellion photonics), and Airborne Differential Absorption Lidar (DIAL). Therefore, we are specifically requesting comments on details related to these and other technologies such as the detection capability; an equivalent fugitive emission repair threshold to what is required in the proposed rule for OGI; the frequency at which the fugitive emissions monitoring survey should be performed and how this frequency ensures appropriate levels of fugitive emissions detection; whether the technology can be used as a stand-alone technique or whether it must be used in conjunction with a less frequent (and how frequent) OGI monitoring survey; the type of restrictions necessary for optimal use; and the information that is important for inclusion in a monitoring plan for these technologies.

H. Proposed Standards for Equipment Leaks at Natural Gas Processing Plants

In the 2012 NSPS, we established VOC standards for equipment leaks at onshore natural gas processing plants in the oil and natural gas source category. In this action, we are proposing methane standards for onshore natural gas processing plants. Based on the analysis below, the proposed methane standards are the same as the VOC standards currently in the NSPS.

Natural gas is primarily made up of methane. However, whether natural gas is associated gas from oil wells or non-associated gas from gas or condensate wells, it commonly exists in mixtures with other hydrocarbons. These hydrocarbons are often referred to as natural gas liquids (NGL). They are sold separately and have a variety of different uses. The raw natural gas often contains water vapor, H_2S, CO_2, helium, nitrogen and other compounds. Natural gas processing consists of separating certain hydrocarbons and fluids from the natural gas to produced ''pipeline quality'' dry natural gas. While some of the processing can be accomplished in the production segment, the complete processing of natural gas takes place in the natural gas processing segment. Natural gas processing operations separate and recover NGL or other nonmethane gases and liquids from a stream of produced natural gas through components performing one or more of the following processes: Oil and condensate separation, water removal, separation of NGL, sulfur and CO_2 removal, fractionation of natural gas liquid and other processes, such as the capture of CO_2 separated from natural gas streams for delivery outside the facility.

In the analysis for the 2012 NSPS, we estimated nationwide methane emissions from equipment leaks at onshore natural gas processing plants to be 51.4 tpy. We identified four control options for reducing methane emissions from these equipment leaks in the 2012 TSD: (1) Subpart VVa level of control; (2) monthly survey using optical gas imaging (OGI) and an annual Method 21 survey; (3) monthly OGI survey without the annual Method 21 survey; and (4) annual OGI survey.

In April 2014, the EPA published the white paper titled ''Oil and Natural Gas Sector Leaks''[116] which summarized the EPA's current understanding of fugitive emissions of methane and VOC at onshore oil and natural gas production, processing, and transmission and storage facilities. The white paper also outlined our understanding of the available mitigation techniques (practices and equipment) available to reduce these emissions along with the cost and effectiveness of these practices and technologies. Based on our review of the public and peer review comments on the white paper and our additional research, we did not identify any additional control options beyond those that we identified for the 2012 NSPS.

For purposes of this action, we have identified two approaches in section VIII.A for evaluating whether the cost of a multipollutant control, such as the leak detection and repair programs described above, is reasonable. As explained in that section above, we believe that both approaches are appropriate for assessing the reasonableness of the multipollutant controls considered in this action. Therefore, we find the cost of control to be reasonable as long as it is such under either of these two approaches.

Under the first approach (single pollutant approach), which assigns all costs to the reduction of one pollutant and zero to all other pollutants simultaneously reduced, we find the cost of control reasonable if it is reasonable for reducing one pollutant alone. The annualized costs for option 1 (subpart VVa level of control) is $45,160 without considering the cost savings of the recovered natural gas, and $33,915 considering the cost savings. We estimate the cost of reducing methane emissions from equipment leaks at natural gas processing plants under this option to be $931 per ton. The annualized costs for option 2 (monthly survey using OGI and annual Method 21 survey) is $87,059 without considering the cost savings of the recovered natural gas, and $75,813 considering the cost savings. We estimate the cost of reducing methane emissions from equipment leaks at natural gas processing plants under this option to be $1,795 per ton. At the time of the analysis for the 2012 NSPS, we were unable to estimate the methane emission reduction of options 3 (monthly OGI survey) and 4 (annual OGI survey-only programs) since OGI currently does not have the capability to quantify emissions.

We find the costs for methane emission reductions for option 1 (subpart VVa level of control) to be reasonable for the amount of methane emissions it can achieve. Also, because all of the costs have been attributed to methane reduction, the cost of simultaneous VOC reduction is zero and therefore reasonable.[117]

Although we propose to find the cost of control to be reasonable because it is reasonable under the above approach, we also evaluated the cost of option 1 (subpart VVa level of control) under the second approach (multipollutant approach). Under the second approach, we apportion the annualized cost across the pollutant reductions addressed by the control option in proportion to the relative percentage reduction of each pollutant controlled. In this case, since methane and VOC are controlled equally, half the cost is apportioned to the methane emission reductions and half the cost is apportioned to the VOC emission reductions. Under this approach, the costs are allocated based on the percentage reduction expected for each pollutant. Because option 1 (subpart VVa level of control) reduces the fugitive emission of natural gas from equipment components, emissions of methane and VOC will be reduced equally. Therefore, we attribute 50 percent of the costs to methane reduction and 50 percent to VOC reduction. Based on this formulation, the costs for methane reduction are half of the estimated costs under the first approach above and are therefore reasonable.

With option 1 (subpart VVa level of control) there would be no secondary air impacts, therefore no impacts were assessed. Also, we did not identify any nonair quality or energy impacts associated with this control technique, therefore no impacts were assessed.

In light of the above, we find that the BSER for reducing methane emissions from equipment leaks at natural gas processing plants is a leak detection and repair program at the subpart VVa level of control, and we are proposing to require such a program at natural gas processing plants. As described above, the proposed methane standard would be the same as the current VOC standard for natural gas processing plants in the NSPS.

I. Liquids Unloading Operations

Liquids unloading is an operation that is conducted at natural gas wells to remove accumulated liquids that can impede or even halt production of natural gas due to insufficient gas flow within the wellbore. Fluid accumulation is a common problem in both aging and newer natural gas wells. The typical industry practices used to accomplish liquids unloading include using plunger lifts, beam pumps, remedial treatments, or venting the well to atmosphere (also referred to as blowing down the well). The emissions from liquids unloading result from the intentional venting of gas from the wellbore during activities conducted on or near equipment associated with the removal of accumulated fluids. The volume of gas vented is presumed to be the total volume of gas in the casing and tubing minus the volume of water accumulated in the well. Wells can require multiple unloading events per year; however, the number and frequency of unloading events and volume of emissions generated vary widely. Some wells conduct liquids unloading without venting, through use of closed-loop systems and other technologies.

Based on the information and data available to the EPA during development of the 2012 NSPS, the EPA conducted a preliminary screening of emissions sources with the goal of maximizing emission reductions for new sources. At the time, there was not sufficient data available to determine whether liquids unloading was an issue for hydraulically fractured wells, which represent the majority of projected future production and new sources. In petitions on the 2012 NSPS, some petitioners asserted that the EPA should have regulated the methane and VOC emissions from liquids unloading operations because these emissions are significant and there are data that demonstrate that cost-effective mitigation technologies are available to address the emissions.

Data on liquids unloading operations supplied to the EPA subsequent to the 2012 rule finalization provided significantly better insight into emissions from liquids unloading. Data were provided in a study conducted by members of the American Petroleum

[116] Available at *http://www.epa.gov/airquality/oilandgas/2014papers/20140415leaks.pdf.*

[117] In 2012 we already found that the cost of this control to be reasonable for reducing VOC emissions from natural gas processing plants. We are not reopening that decision in this action.

Institute (API) and America's Natural Gas Alliance (ANGA) and published in a report titled ''*Characterizing Pivotal Sources of Methane Emissions from Natural Gas Production, Summary and Analysis of API and ANGA Survey Responses'',* hereafter referred to the API/ANGA study, available in the docket. These data demonstrate that venting for liquids unloading can and does result in significant increases in emissions for the well in comparison to wells that do not vent for liquids unloading operations. In addition, data reported to the GHGRP show emissions from venting for liquids unloading similar in magnitude to those calculated using API/ANGA study data.

The 2014 white paper on liquids unloading discussed the most recent information and data available for the analysis of emissions (including the API/ANGA survey and GHGRP data) and industry practices or control technologies available to address these emissions. Commenters on the white paper noted that venting for liquids unloading is a significant source of emissions and that these emissions are highly skewed, with a minority of sources being responsible for a large fraction of total emissions. As a result, commenters urged the EPA to further study these operations and that regulation of those operations at this time would be premature.

Since publication of the white paper, additional data have become available on liquids unloading emissions from Allen et al., 2014. The Allen *et al.* data confirm the findings of previous studies, that venting for liquids unloading is a significant source of emissions and that emissions are highly skewed. Data reviewed also show that liquids unloading events are highly variable and often well-specific. Furthermore, questions remain concerning the difficulty of effective control for these high-emitting events in many cases and the applicability and limitations of specific control technologies such as plunger lift systems for supporting a new source performance standard. For analysis conducted in the development of this proposal, we revised our estimate of methane and VOC emissions from liquids unloading based on the API/ANGA study data and Allen *et al.* Based on the emissions data discussed in the white paper, and on new data available from Allen *et al.,* we believe that the emissions from liquids unloading operations are significant. However, as noted in section VII.I, the EPA does not have sufficient information to propose standards for liquids unloading. The EPA is continuing to study this issue and is soliciting information and data on control technologies or practices for reducing these emissions.

Specifically, we are soliciting comment on the level of methane and VOC emissions per unloading event, the number of unloading events per year, and the number of wells that perform liquids unloading. In addition, we solicit comment on (1) characteristics of the well that play a role in the frequency of liquids unloading events and the level of emissions, (2) demonstrated techniques to reduce the emissions from liquids unloading events, including the use of smart automation, and the effectiveness and cost of these techniques, (3) whether there are demonstrated techniques that can be employed on new wells that will reduce the emissions from liquids unloading events in the future, and (4) whether emissions from liquids unloading can be captured and routed to a control device and whether this has been demonstrated in practice.

IX. Implementation Improvements

A. Storage Vessel Control Device Monitoring and Testing Provisions

We are proposing regulatory text changes that address performance testing and monitoring of control devices used for new storage vessel installations and centrifugal compressor emissions, specifically relating to in-field performance testing of enclosed combustors. Industry reconsideration petitioners assert that the compliance demonstration and monitoring requirements finalized in the 2012 NSPS were overly complex and stringent given the large number of affected storage vessels each year and the remoteness of the well sites at which they are installed. The petitioners argue that the well sites are unmanned for periods of time up to a month. The additional information provided by petitioners raised significant concerns that the compliance monitoring provisions and field testing provisions of the 2012 NSPS may not have been appropriate for the large number of affected storage vessels, which was much greater than we had expected, and of which many are in remote locations.

In the reconsideration of the NSPS that was finalized in 2013, we streamlined certain monitoring and continuous compliance demonstration requirements, while we more fully evaluated the proper requirements. Instead of the detailed Method 21 monitoring requirements, the revised requirements included monthly sensory (*i.e.,* OVA) inspections of: (1) Closed-vent system joints, seams and other sealed connections (*e.g.,* welded joints); (2) other closed-vent system components such as peak pressure and vacuum valves; and (3) the physical integrity of tank thief hatches, covers, seals and pressure relief devices. Instead of the continuous parameter monitoring system (CPMS) requirements, the revised requirements included the following inspection requirements: (1) Monthly observation for visible smoke emissions employing section 11 of EPA Method 22 for a 15 minute period; (2) monthly visual inspection of the physical integrity of the control device; and (3) monthly check of the pilot flame and signs of improper operations. Lastly, instead of the field performance testing requirements in § 60.5413, we required that, where controls are used to reduce emissions, sources use control devices that by design can achieve 95 percent or more emission reduction and operate such devices according to the manufacturer's instructions, procedures and maintenance schedule, including appropriate sizing of the combustor for the application.

After evaluating these streamlined requirements and other potential options, we believe that performance testing of enclosed combustors is necessary to assure that they are achieving the required 95 percent control. However, petitioners also assert that the previous performance testing requirements were unreasonably strenuous for a control device needing to demonstrate 95 percent control efficiency. They assert that in order for an enclosed combustor to meet a requirement of 20 parts per million volume (ppmv) it would have to be achieving greater than the required 95 percent control. After an evaluation of the requirement we agree with the comment and are proposing to revise this requirement from 20 ppmv to 600 ppmv; a value that more appropriately reflects 95 percent control of VOC inflow to these control devices. The EPA solicits comment on the appropriateness of this level of control and invites commenters to provide data that demonstrates the VOC composition of field gas from a variety of oil and gas field well sites across the nation.

As proposed, initial and ongoing performance testing will be required for any enclosed combustors used to comply with the emissions standard for an affected facility and whose make and model are not listed on the EPA Oil and Natural Gas Web site (*http://www.epa.gov/airquality/oilandgas/implement.html*) as those having already met a Manufacturer's Performance Test demonstration. Performance testing of combustors not listed at the above site would also be conducted on an ongoing basis, every 60 months of service, and monthly monitoring of visible emissions from each unit is also required.

We are proposing amendments to make the requirements for monitoring of visible emissions consistent for all enclosed combustion units. Currently enclosed combustors that have met the Manufacturer's Performance Test requirement must conduct quarterly observation for visible smoke emissions employing section 11 of EPA Method 22 for a 60 minute period. 40 CFR 60.5413(e)(3). Certain petitioners have suggested it may ease implementation to adjust the frequency and duration to monthly 15 minute EPA Method 22 tests, which is currently required for continuous monitoring of enclosed combustors that are not manufacturer tested. 40 CFR 60.5417(h)(1). If this change were made then all enclosed combustors would have the same monitoring requirements which could potentially make compliance easier for owners and operators. Because both monitoring requirements assure compliance of the enclosed combustors, and having the same requirement would ease implementation burden, we propose to amend 40 CFR 60.5413(e)(3) to require monthly 15 minute-period observation using EPA Method 22 Test, as suggested by the petitioner.

B. Other Improvements

Following publication of the 2012 NSPS and the 2013 storage vessel amendments, we subsequently determined, following review of reconsideration petitions and discussions with affected parties, that the final rule warrants correction and clarification in certain areas. Each of these areas is discussed below.

1. Initial Compliance Requirements for Bypass Devices

Initial compliance requirements in § 60.5411(c)(3)(i)(A) for a bypass device that could divert an emission stream away from a control device were previously amended to allow for initiating a notification via remote alarm to the nearest field office indicating that the bypass device was activated. However, the previous amendments did not address parallel requirements for continuous compliance in § 60.5416. In order to maintain consistency with the previously amended § 60.5411, we are proposing to amend § 60.5416(c)(3)(i) to include notification via remote alarm to the nearest field office. We are proposing to require both an alarm at the bypass device and a remote alarm. This is important in this source category due to the great number of unmanned sites, especially well sites. Previously, the only option was an alarm at the device location. We believe this change will ensure that personnel will be alerted to a potential uncontrolled emissions release whether they are in the vicinity of the bypass device when it is activated or at a remote monitoring location. Finally, we are proposing similar amendments to parallel requirements at § 60.5411(a)(3)(i)(A) for closed vent systems used with reciprocating compressors and centrifugal compressor wet seal degassing systems.

2. Recordkeeping Requirements

Petitioners noted that the recordkeeping requirements of § 60.5420(c) do not include the repair logs for control devices failing a visible emissions test required by § 60.5413(c). We agree that these recordkeeping requirements should be listed and are proposing to add them at § 60.5420(c)(14).

3. Due Date for Initial Annual Report

Petitioners pointed out that the preamble to the 2013 final rule stated that the initial annual report is due on January 15, 2014; however, § 60.5420(b) states that initial annual report is due 90 days after the end of the initial compliance period. The petitioners correctly contend that this equates to a due date of January 13, 2014. Although we inadvertently stated a date three months after the end of the initial compliance period (rather than 90 days after) in the preamble, we are not proposing to amend the rule at this time. Rather, we will consider any initial annual report submitted no later than January 15, 2014 to be a timely submission. All subsequent annual reports must be submitted by the correct date of January 13 of the year.

4. Flare Design and Operation Standards

The petitioners requested that the EPA clarify the regulatory compliance requirements for storage vessel affected facilities with respect to flares. Currently subpart OOOO contains conflicting references to the NSPS general provisions that obscures the EPA's intent to require compliance with the requirements for the design and operation of flares under § 60.18 of the General Provisions. To clarify EPA's intent, the EPA is proposing to remove the provision of Table 3 in subpart OOOO that exempts flares from complying with the requirements for the design and operation of flares under 40 CFR 60.18 of the General Provisions. By removing the exemption from the General Provisions from subpart OOOO, this clarifies that flares used to comply with subpart OOOO are subject to the design and operation requirements in the general provisions.

It has recently come to EPA's attention that that there may be affected facilities which use pressure assisted-flares (e.g., sonic flares) to control emissions during periods of startup, shutdown, emergency and/or maintenance activities. While compliance with the NSPS emission limits can be achieved using such flares, when designed and operated properly, it is EPA's understanding that pressure-assisted flares cannot meet the maximum exit velocity of 400 feet per second as required by 40 CFR 60.18(b). Pressure-assisted flares are designed to operate with a high velocities up to sonic velocity conditions (*e.g.*, 700 to 1,400 feet per second) for common hydrocarbon gases.

In order to evaluate the use of pressure-assisted flares by the oil and natural gas industry and determine whether to develop operating parameters for pressure-assisted flares for purposes of subparts OOOO (and subpart OOOOa should it be finalized), the EPA is soliciting comment on where in the source category, under what conditions (*e.g.*, maintenance), and how frequently pressure-assisted flares are used to control emissions from an affected facility, as defined within this subpart. In addition, we request information on: (1) The importance of, and assessment of flame stability; (2) the importance of, and ranges of the heat content of flared gas; (3) the importance and ranges of gas pressure and flare tip pressure; (4) the importance of and examples of appropriate flare head design; (5) a cross-country review of waste gas composition; (6) and appropriate methodology to measure the resultant flare destruction efficiency. The EPA also requests comment on the appropriate parameters to monitor to ensure continuous compliance. This information is critical for the potential development of operating parameters for pressure-assisted flares given the limited to no information currently available for this type of flare in the oil and natural gas industry.

5. Exemption to Notification Requirement for Reconstruction

The petitioners asked for the EPA to consider whether a single remaining notification of reconstruction required under § 60.15(d) of the General Provisions was necessary, given that the EPA had already provided an exemption to parallel requirements for construction, startup, and modification. The EPA agrees with the petitioner that the notification of reconstruction requirements under § 60.15(d) is unnecessary. The EPA considers it unnecessary because subpart OOOO specifies notification of reconstruction for affected unit pneumatic controllers, centrifugal compressors, and storage vessels under § 60.5410 and § 60.5420 in lieu of the general notification requirement in § 60.15(d). The EPA, therefore, proposes to add in Table 3 that § 60.15(d) does not apply to affected facility pneumatic controllers, centrifugal compressors, and storage vessels subject to subpart OOOO.

6. Disposal of Carbon From Control Devices

We are re-proposing the provisions for management of waste from spent carbon canisters that were finalized in § 60.5412(c)(2) of the 2012 NSPS to allow for comment. Petitioners assert that the requirements for RCRA-level management of waste from spent carbon canisters are unnecessary and overly burdensome. Further, they assert that those provisions were not in the proposal which excluded them from review and comment. We do not agree that these provisions are overly burdensome because RCRA hazardous waste units are not the only options made available to manage the spent carbon. In the scenario where the carbon is to be burned, the EPA sought a means to assure that sufficient precaution was taken to assure complete destruction of the carbon and adsorbed compounds. These same requirements apply to spent carbon from units subject to NESHAP subpart HH in oil and natural gas production, further supporting our decision to seek consistent and appropriate levels of control for burning spent carbon from an adsorption system. We are re-proposing the provisions here to allow for review and comment. Petitioners may submit alternatives that would allow for consistent treatment of spent carbon from the oil and natural gas sector, and that assure destruction of the compounds adsorbed in carbon adsorption control units.

7. Definition of Capital Expenditure

Petitioners requested that the EPA clarify the definition of ‘‘capital expenditure’’ in subpart OOOO. The term is used in section § 60.5365(f), which describes the applicability of the equipment leaks provisions for onshore natural gas processing plants. Specifically, 40 CFR 60.5365(f)(1) states that ‘‘addition or replacement of equipment for the purpose of process improvement that is accomplished without a capital expenditure shall not by itself be considered a modification under this subpart.’’ Subpart OOOO does not define ‘‘capital expenditure’’ but states in 40 CFR 60.5430 (definition section) that ‘‘all terms not defined herein shall have the meaning given them in the Act, in subpart A or subpart VVa of part 60.’’ The term ‘‘capital expenditure’’ is defined in the General Provisions subpart A, as well as in subpart VVa. However, this definition in subpart VVa is currently stayed. The EPA agrees with the commenter that this capital expenditure approach applies to onshore natural gas processing plants that are subject to subpart OOOO. The EPA had previously adopted this method for determining modification in subpart KKK. In fact, the capital expenditure provision in subpart OOOO, 40 CFR 60.5365(f)(1) was carried over from subpart KKK 40 CFR 60.630(c). Subpart KKK does not specifically define ‘‘capital expenditure;’’ it states in 40 CFR 60.631 that ‘‘as used in this subpart, all terms not defined herein shall have the meaning given them in the Act, in subpart A or subpart VV of part 60. . .’’ This means that the definition of capital expenditure in subpart KKK is the current definition in VV.

In conducting the EPA’s 8-year review of subpart KKK, the EPA promulgated subpart OOOO, which includes certain revisions to subpart KKK. The EPA revised the existing NSPS requirements for LDAR to reflect the procedures and leak definition established by 40 CFR part 60, subpart VVa (77 FR 49498). Specifically, the revision to subpart KKK, which is codified in subpart OOOO, includes a lower leak definitions for valves and pumps and requires monitoring of connectors.

The EPA’s 8-year review and revision of subpart KKK did not include any change to the capital expenditure provision as it applies to oil and natural gas processing plants. This means that the technique used to determine whether there is a modification based on capital expenditure under OOOO remains the same technique as in subpart KKK (*i.e.*, based on the definition of ‘‘capital expenditure’’ in subpart VV).

However, as the petitioner correctly noted, the year that is the basis for calculating Y (the percent of replacement cost) is designed to reflect the year of the proposed standards for the relevant subpart at issue; as such, the definition of ‘‘capital expenditure’’ in subpart VV does not reflect the year subpart OOOO was proposed (*i.e.*, 2011) and is therefore inaccurate for application to subpart OOOO as is. To address this issue, the EPA is proposing to provide in subpart OOOO a definition for ‘‘capital expenditure’’ that essentially mirrors [118] the definition in subpart VV but with the year revised to reflect the year subpart OOOO was proposed (*i.e.*, 2011).

The EPA disagrees with the petitioner that the appropriate applicable basic annual asset guideline repair allowance, designated ‘‘B’’ in the formula, is 12.5, which is the B value for Subpart VVa. Since ‘‘capital expenditure’’ method was not among the updates the EPA made in its review of the subpart KKK (and subpart OOOO is the updated version of KKK), the allowance in KKK (*i.e.*, 4.5 according to subpart VV) remains applicable to onshore gas affected facilities. Further, B values are based on the annual asset guideline repair allowance specified in IRS Revenue Procedure 83–35. The specified allowance value is 4.5 for exploration and production of petroleum and natural gas deposits. Also, as evident from the ‘‘capital expenditure’’ definitions in both subparts VV and VVa, the B values are subpart-specific and therefore the EPA has promulgated specific B values for different subparts. Whereas subpart VV includes a specific B value for natural gas processing plants covered by subpart KKK (natural gas processing plants), there is no such value in subpart VVa referencing subpart KKK. For the reasons stated above, the EPA clarifies that the B value for purposes of subpart OOOO is 4.5; it is not 12.5, as the petitioner suggests.

In sum, to provide clarity the EPA is proposing to specifically define the term ‘‘capital expenditure’’ in subpart OOOO. In this proposed definition, EPA is updating the formula to reflect the calendar year that subpart OOOO was proposed, as well as specifying that the B value for subpart OOOO is 4.5. These updates are necessary for proper calculation of capital expenditure under subpart OOOO.

8. Initial Compliance Clarification

An issue was raised in an administrative petition that EPA did not adequately respond to a comment on the 2011 proposed NSPS regarding compliance period for the LDAR requirements for On-Shore Natural Gas Processing Plants. The comment at issue [119] requested that EPA include in

[118] The proposed definition does not include B values listed in subpart VV for other subparts because those values are irrelevant to subpart OOOO.

[119] Comments of the Gas Processors Association Regarding the Proposed Rule, Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air

Continued

subpart OOOO a provision similar to subpart KKK, 40 CFR 60.632(a), which allows a compliance period of up to 180 days after initial start-up. The commenter was ''concerned that a modification at an existing facility or a subpart KKK regulated facility could subject the facility to Subpart OOOO LDAR requirements without adequate time to bring the whole process unit into compliance with the new regulation.'' [120]

We clarify that subpart OOOO, as promulgated in 2012, already includes a provision similar to subpart KKK, § 60.632(a), as requested in the comment. Specifically, § 60.5400(a) requires compliance with 40 CFR 60.482–1a(a), which provides that ''[e]ach owner or operator subject to the provisions of this subpart shall demonstrate compliance . . . within 180 days of initial startup.'' This provision applies to all new, modified, and reconstructed sources. With respect to modification, which was of specific concern to the commenter, a change to a unit sufficient to trigger a modification and thus application of the subpart OOOO LDAR requirements for on-shore natural gas processing plants would be followed by startup, which would mark the beginning of the 180 day compliance period provided in 40 CFR 60.482–1a(a) (incorporated by reference in subpart OOOO § 60.5400(a)).

9. Tanks Associated With Water Recycling Operations

In many cases, flowback water from well completions and water produced during ongoing production is collected, treated and recycled to reduce the volume of potable water withdrawn from wells or other sources. Large, non-earthen tanks are used to collect the water for recycling following separation to remove crude oil, condensate, intermediate hydrocarbon liquids and natural gas. These collection tanks used for water recycling are very large vessels having capacities of 25,000 barrels or more, with annual throughput of millions of barrels of water. In contrast, industry standard storage vessels commonly found in well site tank batteries and used to contain crude oil, condensate, intermediate hydrocarbon liquids and produced water typically have capacities in the 500 barrel range.

In the 2012 NSPS, we had envisioned the storage vessel provisions as regulating the vessels in well site tank batteries and not these large tanks primarily used for water recycling. It was never our intent to cover these large water recycling tanks. It recently came to our attention that these water recycling tanks could be inadvertently subject to the NSPS due to the extremely low VOC content combined with the millions of barrels of throughput each year, which could result in a potential to emit VOC exceeding the NSPS storage vessel threshold of 6 tpy.[121] The EPA encourages efforts on the part of owners and operators to maximize recycling of flowback and produced water. We are concerned that the inadvertent coverage of these tanks under the NSPS could discourage recycling. It is our understanding that, due to the size and throughput of these tanks, combined with the trace amounts of VOC emissions that are difficult to control, that operators may choose to discontinue recycling to avoid noncompliance with the NSPS.

As a result, we are considering changes in the final rule to remove tanks that are used for water recycling from potential NSPS applicability. We solicit comment on approaches that could be taken to amend the definition of ''storage vessel'' or other changes to the NSPS that would resolve this issue without excluding storage vessels appropriately covered by the NSPS. In addition, we solicit comment on location, capacity or other criteria that would be appropriate for such purpose.

X. Next Generation Compliance and Rule Effectiveness

A. Independent Third-Party Verification

The EPA is taking comment on establishing a third-party verification program as discussed below. Third-party verification is when an independent third-party verifies to a regulator that a regulated entity is meeting one or more of its compliance obligations. The regulator retains the ultimate responsibility to monitor and enforce compliance but, as a practical matter, gives significant weight to the third-party verification provided in the context of a regulatory program with effective standards, procedures, transparency and oversight. While requiring regulated entities to monitor and report should improve compliance by establishing minimum requirements for a regulated entity's employees and managers, well-structured third-party compliance monitoring and reporting may further improve compliance.

The third-party verification program would be designed to ensure that the third-party reviewers are competent, independent, and accredited, apply clear and objective criteria to their design plan reviews, and report appropriate information to regulators. Additionally, there would need to be mechanisms to ensure regular and effective oversight of third-party reviewers by the EPA and/or states which may include public disclosure of information concerning the third parties and their performance and determinations, such as licensing or registration.

The EPA is considering a broad range of possible design features for such a program under the following two scenarios: (A) Third-Party Verification of Closed Vent System Design and (B) Third-Party Verification of IR Camera Fugitives Monitoring Program. These include those discussed or included in the following articles, rules, and programs:

(1) Lesley K. McAllister, Regulation by Third-Party Verification, 53 B.C. L. REV. 1, 22–23 (2012);

(2) Lesley K. McAllister, THIRD–PARTY PROGRAMS FINAL REPORT (2012) (prepared for the Administrative Conference of the United States), available at *http://www.acus.gov/report/third-party-programs-final-report;*

(3) Esther Duflo *et al.,* Truth-Telling By Third-Party Auditors and the Response of Polluting Firms: Experimental Evidence From India, 128 Q. J. OF ECON. 4 at 1499–1545 (2013);

(4) EPA CAA Renewable Fuel Standard (RFS) program: The RFS regulations include requirements for obligated parties to, in relevant part, submit independent third-party engineering reviews to the EPA before generating Renewable Identification Numbers (RINs).[122]

(5) Massachusetts Underground Storage Tank (UST) third-party inspection program: The owners/operators of most underground storage tanks in Massachusetts are required to have their USTs inspected by third-party inspectors every three years. While the third-party inspectors are hired directly by the tank owners and operators, they report to the Massachusetts Department of Environmental Protection (MassDEP). The third parties conduct and document detailed inspections of USTs and piping systems, review facility recordkeeping to ensure it meets UST program requirements, and submit reports on their findings electronically to MassDEP.[123]

Pollutants Reviews, 76 FR 52738 (Aug. 23, 2011). Pp. 3, 32–33.

[120] Comments of the Gas Processors Association Regarding the Proposed Rule, Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews, 76 FR 52738 (Aug. 23, 2011). Pp. 33.

[121] Letter from Obie O'Brien, Vice President—Government Affairs/Corporate Outreach, Apache Corporation, to EPA Docket, Docket ID Number EPA–HQ–OAR–2010–4755, April 20, 2015. Similar letters from Rockwater Energy Solutions (EPA–HQ–OAR–2010–4756) and Permian Basin Petroleum Association (EPA–HQ–OAR–2010–4757).

[122] EPA, Renewable Fuel Standards (RFS), *http://www.epa.gov/OTAQ/fuels/renewablefuels/.*

[123] MassDEP, Third-Party Underground Storage Tank (UST) Inspection Program, *http://*

(6) Massachusetts licensed Hazardous Waste Site Cleanup Professional program: Private parties who are financially responsible under Massachusetts law for assessing and cleaning up confirmed and suspected hazardous waste sites must retain a licensed Hazardous Waste Site Cleanup Professional (commonly called a ''Licensed Site Professional'' or simply an ''LSP'') to oversee the assessment and cleanup work.[124]

We have identified one potential area for third-party verification under this rule.

Professional Engineer Certification of Closed Vent System and Control Device Design and Installation

When produced liquids from oil and natural gas operations are routed from the separator to the condensate storage tank, a drop in pressure from operating pressure to atmospheric pressure occurs. This results in ''flash emissions'' as gases are liberated from the condensate stream due to the change in pressure. The magnitude of flash emissions can dwarf normal working and breathing losses of a storage tank. If the control system (closed vent system and control device, including pressure relief devices and thief hatches on storage vessels) cannot accommodate the peak instantaneous flow rate of flash emissions, working losses, breathing losses and any other additional vapors, this may cause pressure relief devices and thief hatches to ''pop'' and they may not properly reseat, resulting in immediate and potentially continuing excess emissions. Through our energy extraction enforcement initiative, we have seen this to be the case, due in large part to undersized control systems that may have been inadequately designed to accommodate only working and breathing losses of a storage tank. We have worked in conjunction with states, including Colorado, in conducting inspection campaigns associated with storage vessels. In two inspection campaigns, in two different regions, we recorded venting from thief hatches or other parts of the control system at over 60 percent of the tank batteries inspected. Another inspection campaign resulted in a much higher leak rate, with 23 of 25 tank batteries experiencing fugitive emissions.

One potential remedy for the inadequate design and sizing of the closed vent system would be to require an independent third-party (independent of the well site owner/operator and control device manufacturer), such as a professional engineer, to review the design and verify that it is designed to accommodate all emissions scenarios, including flash emissions episodes. Another element of the professional engineer verification could be that the professional engineer verifies that the control system is installed correctly and that the design criteria is properly utilized in the field.

Another approach to detecting overpressure in a closed vent system would be to require a continuous pressure monitoring device or system, located on the thief hatches, pressure relief devices and other bypasses from the closed vent system. Through our inspections, we have seen thief hatch pressure settings below the pressure settings of the storage tanks to which they are affixed. This results in emissions escaping from the thief hatch and not making it to the control device.

The EPA requests comment on these approaches. Specifically, we request comment as to whether we should specify criteria by which the PE verifies that the closed vent system is designed to accommodate all streams routed to the facility's control system, or whether we might cite to current engineering codes that produce the same outcome. We also request comment as to what types of cost-effective pressure monitoring systems can be utilized to ensure that the pressure settings on relief devices is not lower than the operating pressure in the closed vent to the control device and what types of reporting from such systems should be required, such as through a supervisory control and data acquisition (SCADA) system.

B. Fugitives Emissions Verification

As discussed in sections VII.G and VIII.G, the EPA is proposing the use of OGI as a low cost way to find leaks. While we believe we are proposing a robust method to ensure that OGI surveys are done correctly, we have ample experience from our enhanced leak detection and repair (LDAR) efforts under our Air Toxics Enforcement Initiative, that even when methods are in place, routine monitoring for fugitives may not be as effective in practice as in design. Similar to the audits included as part of consent decrees under the Initiative (*See U.S. et. Al.* v. *BP Products North America Inc.),* we are soliciting comment on an audit program of the collection of fugitive emissions components at well sites and compressor stations.

For this rule, we are anticipating a structure in which the facilities themselves are responsible for determining and documenting that their auditors are competent and independent pursuant to specified criteria. The Agency seeks comment as to whether this approach is appropriate for the type of auditing we describe below, or whether an alternative approach, such as requiring auditors to have accreditation from a recognized auditing body or EPA, or other potentially relevant and applicable consensus standards and protocols (*e.g.*, American National Standards Institute (ANSI), ASTM International (ASTM), European Committee for Standardization (CEM), International Organization for Standardization (ISO), and National Institute of Standards and Technology (NIST) standards), would be preferable.

In order to ensure the competence and independence of the auditor, certain criteria should be met. Competence of the auditor can include safeguards such as licensing as a Professional Engineer (PE), knowledge with the requirements of rule and the operation of monitoring equipment (*e.g.*, optical gas imaging), experience with the facility type and processes being audited and the applicable recognized and generally accepted good engineering practices, and training or certification in auditing techniques.

Independence of the auditor can be ensured by provisions and safeguards in the contracts and relationships between the owner and operator of the affected facility with auditors. These can include: The auditor and its personnel must not have conducted past research, development, design, construction services, or consulting for the owner or operator within the last 3 years; the auditor and its personnel must not provide other business or consulting services to the owner or operator, including advice or assistance to implement the findings or recommendations in the Audit report, for a period of at least 3 years following the Auditor's submittal of the final Audit report; and all auditor personnel who conduct or otherwise participate in the audit must sign and date a conflict of interest statement attesting the personnel have met and followed the auditors' policies and procedures for competence, impartiality, judgment, and operational integrity when auditing under this section; and must receive no financial benefit from the outcome of the Audit, apart from payment for the auditing services themselves. In addition, owners or operators cannot provide future employment to any of the auditor's personnel who conducted or otherwise participated in the Audit for a period of at least 3 years following the Auditor's submittal of its final Audit report and must be empowered to direct

www.mass.gov/eea/agencies/massdep/toxics/ust/third-party-ust-inspection-program.html.

[124] *http://www.mass.gov/eea/agencies/massdep/cleanup/licensed-site-professionals.html.*

their auditors to produce copies of any of the audit-related reports and records specified in those sections. Both the owners and operators and their auditors should sign supporting certifications statements. To further minimize audit bias, an audit structure might require that audit report drafts and final audit reports be submitted to EPA at the same time, or before, they are provided to the owners and operators. Furthermore, the audits conducted by the auditors under this rule should not be claimed as a confidential attorney work products even if the auditors are themselves, or managed by or report to, attorneys.

There may be other options, in addition to the approaches above, that may increase owner or operator flexibility, but these options also present risks of introducing bias into the program, resulting in less robust and effective audit reports. EPA invites comment on the structure above as well as alternative auditor/auditing approaches with less rigorous independence criteria. For example, EPA could, in the final rule, allow for audits to be performed by auditors with some potential conflicts of interest (*e.g.*, employees of parent company, affiliates, vendors/contractors that participated in developing source master plan(s) and/or site-specific plan(s), etc.) and/or allow a person at the facility itself who is a registered PE or who has the requisite training in conducting optical gas imaging monitoring to conduct the audit. If such approaches are adopted in the final rule, the Agency could seek to place appropriate restrictions on auditors and auditing with less than full independence from their client facilities in an effort to increase confidence that the auditors will act accurately when performing their activities under the rule. Such provisions could include ones addressed to ensuring that auditor personnel who assess a facility's compliance with the fugitives monitoring requirements do not receive any financial benefit from the outcome of their auditing decisions, apart from their basic salaries or remuneration for having conducted the audits.

Additional examples of the types of restrictions that could be placed on such self-auditing to potentially improve auditor impartiality and auditing outcomes appear in the U.S. and CARB v. Hyundai Motor Company, et al. Consent Decree (CD). Until the CDs corrective measures are fully implemented, the defendants must audit their fleets to ensure that vehicles sold to the public conform to the vehicles' certification. The CD provides that the audit team will be in the United States, will be independent from the group that performed the original certification work, and must perform their audits without access to or knowledge of the defendants' original certification test data which the CD-required audits are intended to backcheck. EPA seeks comment as to whether similar restrictions could be effective for any potential enhanced self-auditing conducted under the rule.

Finally, EPA seeks comment on whether, and to what extent, the public should have access to the compliance reports, portions or summaries of them and/or any other information or documentation produced pursuant to the auditing provisions. EPA is also considering the approach it should take to balance public access to the audits and the need to protect Confidential Business Information (CBI). To balance these potentially competing interests, EPA is reviewing a variety of approaches that may include limiting public access to portions of the audits and/or posting public audit grades or scores to inform the public of the auditing outcomes without compromising confidential or sensitive information. EPA seeks comment on these transparency and public access to information issues in the context of the proposed auditing provisions.

A suggested structure which incorporates concepts from the discussion above, and relevant to an audit of the fugitives monitoring program of the collection of fugitive emissions components at well sites and compressor stations could include the following structure:

Within the first year of applicability to the rule, an OGI trained auditor, experienced with the facility type and processes being audited and the applicable recognized and generally accepted good engineering practices, and trained or certified in auditing techniques, and who has not:

a. served as a fugitive emissions monitoring technician at the source,

b. conducted past research, development, design, construction services, or consulting for the owner or operator within the last 3 years or;

c. provided other business or consulting services to the owner or operator, including advice or assistance to implement the findings or recommendations in the Audit report, for a period of at least 3 years following the Auditor's submittal of the final Audit report;

shall:

a. Verify that the source has established a master and site specific monitoring plan;

b. Verify that the master and site specific monitoring plan includes the elements described in the rule;

c. Verify that the fugitive components were monitored in accordance with the master and site specific monitoring plan and at the appropriate frequency under the plan(s) and the rule;

d. Verify that proper documentation and sign offs have been recorded for all fugitive components placed on the delay of repair list;

e. Ensure that repairs have been performed in the required periods under the rule;

f. Review monitoring data for feasibility (*e.g.*, do the survey results reflect a feasible timeframe in which to conduct the monitoring survey) and unusual trends;

g. Verify that proper calibration records and monitoring instrument maintenance information are maintained;

h. Verify that other fugitives emissions monitoring records are maintained as required; and

i. Observe in the field each technician who is conducting fugitive emissions monitoring to ensure that monitoring is being conducted as described in the rule and the master and site specific plan;

j. Submit a report to the EPA and the facility outlining the findings of the audit with deficiencies and corrective actions provided.

k. Sign a certification statement that the report was prepared by the auditor conducting the audit (or under his/her direction or supervision), that the report is true, accurate, and complete, that the Audit was prepared pursuant to, and meets the requirements of, 40 CFR part 60 subpart OOOOa, and any other applicable auditing, competency, and independence/impartiality/conflict of interest standards and protocols.

Upon the receipt of the auditor's report, the source should correct any deficiencies detected or observed within four months. The source would be required to maintain a record that: (i) Records the auditor's report; and (ii) describes the nature and timing of any corrective actions taken. The source would be required to submit in their periodic compliance report, a summary of the findings of the auditor's report and a description and timing of any corrective actions taken. EPA envisions that the audit would be repeated with some frequency and requests comment on the appropriate frequency, and any actions, trends or compliance triggers which might require or allow deviation from the frequency.

C. Third-Party Information Reporting

Third-party information reporting occurs when a third-party reports information on a regulated source's performance, directly to the regulator. To promote improved compliance, third-party information reporting reduces information asymmetries between what the regulated entities know about themselves and the regulators' knowledge about the entities.

An example of third-party information reporting involves federal income tax law where certain income must be independently reported to the Internal Revenue Service (IRS) by payers of the income. Because the information is required to be identical to that reported by taxpayers, the government can compare the dual disclosures for consistency. Taxpayers know this and are deterred from failing to report or underreporting.

We outlined a potential third-party information reporting structure for oil and natural gas in our 2013 proposed amendments. We continue to believe that application of such a reporting structure is a natural outgrowth for implementation of the manufacturer performance testing requirements under subpart OOOO and subparts HH/HHH. As previously discussed in the 2013 proposal, an owner or operator that purchases a specific model of control device that the manufacturer has demonstrated achieves the combustion control device performance requirements in NSPS subpart OOOO (a ''listed device'') is exempt from conducting their own performance test and submitting performance test results. To provide further incentive to use such a listed device, the EPA can ''level the playing field'' by ensuring that exemption claims are valid. Using the framework of third-party information reporting, the owner or operator would demonstrate initial compliance by providing proof of purchase of the listed device, reporting certain information, such as device model, serial number, geospatial coordinates and date of installation in their annual report following the end of the compliance period during which the device was installed. In the final rule, the EPA could conceivably supplement the owner/operator reporting requirement with a manufacturer reporting requirement providing the names of entities that had purchased the listed device. The manufacturer report to the EPA could be very simple, such as a ''notice and go'' or ''post card'' type report. This could allow a simple cross check of the owner's or operator's report with the manufacturer's sales confirmation, making compliance checks easy and provide assurance to the Agency that the source has in fact purchased and installed a manufacturer performance tested device, improving compliance with the rule.

As noted above, we have currently evaluated and posted 15 enclosed combustor models, allaying concerns that it would take ''years of work'' to avoid compliance complications with the process. The EPA continues to encourage the option to use listed devices and believe that operators have an incentive to do so, in lessened initial and on-going compliance demonstration costs. Third-party information reporting could lessen any lingering concerns with implementation and potential compliance complications. However, we understand the issues for this sector, with making the ''postcard'' model work as we envisioned. One of the issues is related to the granularity of the reporting by the manufacturer as compared to the reporting by the source to the EPA or delegated authority. For example, the manufacturer may only know that they sold 500 units of a particular control device, but may not know where it is actually installed. Lack of a unique ''user ID'' being reported by both sides can limit the utility of the postcard model in this instance. We solicit comment on potential third-party approaches such as the ''post card'' reporting described above that could be implemented to streamline and enhance compliance.

As stated above, a primary concern is that an owner or operator would install a control device, and not conduct a performance test, claiming that they installed a device listed on the Oil and Gas page. We believe that we can build on the success of GIS imbedded digital photos for green completions (''REC PIX''), already in the rule, by developing a similar requirement for installed manufacturer tested control devices. Enhancing the records and reports by requiring specifics of the control device (make, model and serial number) and requiring the digital picture, will allow us to match a particular control device at a specific location with control device models listed on the Oil and Gas page.[125] Having this information electronically reported to CEDRI will further enhance our ability to evaluate compliance with the rule.

While we are soliciting comment on third-party reporting by combustor vendors directly to the EPA, we propose to require that owners or operators include information regarding purchase of a pre-tested combustor model in their Notice of Compliance Status as part of the first annual report following the compliance period in which the combustor commences operation. The information would include (1) make, model and serial number of the purchased device; (2) date of purchase; (3) inlet gas flow rate; (4) latitude and longitude of the emission source being controlled by the combustor; (5) digital GIS and date stamp-imbedded photo of the combustor once it is installed; and (6) certification of continuous compliance. The owner or operator would be required to submit information to CEDRI in lieu of a field performance test.

D. Electronic Reporting and Transparency

1. Include Robust Federal Reporting With Easy Access to Information

We have the opportunity to expand transparency by making the information we have today more accessible, and making new information, obtained from advanced emissions monitoring and electronic reporting, publicly available. This approach will empower communities to play an active role in compliance oversight and improve the performance of both the government and regulated entities. On September 30, 2013, the EPA established that the default assumption for all new EPA rules is to use e-reporting, absent a compelling reason to use paper reporting.[126] Current reporting requirements in most rules and permits direct regulated entities to submit paper reports and forms to the EPA, states, and tribes. Under electronic, or e-reporting, paper reporting is replaced by standardized, Internet-based, electronic reporting to a central repository using specifically developed forms, templates and tools. E-reporting is not simply a regulated entity emailing an electronic copy of a document (*e.g.*, a PDF file) to the government, but also a means to make collected information easily accessible to the public and other stakeholders.

On March 20, 2015, the EPA proposed the ''Electronic Reporting and Recordkeeping Requirements for New Source Performance Standards'' (80 FR 15099, March 20, 2015). If adopted, the rule would revise the part 60 General Provisions and various NSPS subparts in part 60 of title 40 of the Code of Federal Regulations (CFR) to require affected facilities to submit specified air emissions data reports to the EPA electronically and to allow affected facilities to maintain electronic records of these reports. This proposed rule focuses on the submission of electronic reports to the EPA that provide direct measures of air emissions data such as summary reports, excess emission reports, performance test reports and performance evaluation reports.

Subpart OOOO is one of the rules potentially affected by this rulemaking. When promulgated, § 60.5420(c)(9) would be amended to require the submittal of reports to the EPA via the CEDRI. (CEDRI can be accessed through the EPA's CDX (*https://cdx.epa.gov/*).) The owner or operator would be

[125] See *www.epa.gov/oilandgas.*

[126] EPA, Policy Statement on E-Reporting in EPA Regulations (September 30, 2013).

required to use the appropriate electronic report in CEDRI for this subpart or an alternate electronic file format consistent with the extensible markup language (XML) schema listed on the CEDRI Web site (*http://www.epa.gov/ttn/chief/cedri/index.html*). If the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, the owner or operator would submit the report to the Administrator at the appropriate address listed in § 60.4 of the General Provisions. The owner or operator must begin submitting reports via CEDRI no later than 90 days after the form becomes available in CEDRI. The EPA is currently working to develop the form for subpart OOOO.

2. Potential To Enhance Public Transparency Through Web Site Posting on Company Maintained Web Site

The public disclosure of compliance information by regulated entities to customers, ratepayers, or stakeholders has been shown to reduce pollution and improve compliance. This disclosure will empower communities and other stakeholders to play an active role in compliance oversight and improve the performance of both the government and regulated entities. A study of the Safe Drinking Water Act's (SDWA) Consumer Confidence Reports (CCR) requirements linked direct disclosures of compliance information to drinking water customers to statistically significant compliance improvements and reduced pollution.[127] Additional studies have linked public information disclosure to pollution reductions,[128] improved water pollution control practices,[129] reduced air emissions and improved environmental regulatory compliance,[130] and health and safety improvements in the automobile and restaurant markets.

A 2014 study specific to the oil and natural gas industry [131] relied solely on publicly available information that companies provide on their Web sites, or in publicly released financial statements or other reports linked from their Web sites. The report focused on promoting improved operational practices among oil and natural gas companies engaged in horizontal drilling and hydraulic fracturing. According to the report, ''[f]ollowing the maxim of what gets measured, gets managed,'' this report encourages oil and natural gas companies to increase disclosures about their use of current best practices to minimize the environmental risks and community impacts of their ''fracking'' activities. A key finding of the report was that across the industry, ''companies are failing to provide investors and other key stakeholders with quantitative, play-by-play disclosure of operational impacts and best management practices'' (while noting an increase in any level of reporting over 2013).

The EPA solicits comment on requiring owners and operators of affected facilities to report quantitative environmental results on their corporate maintained Web sites. Such results might include monitoring data (including fugitives), quantification of excess emissions and corrective actions, results of performance tests, affected facility status with respect to a standard contained in a rule, and third-party certifications. The EPA requests comment on whether all owner and operators should be required to do this, or only a subset (e.g., based on size of entity, complexity or number of operations, web presence, etc.) and what data we should require them to report; keeping in mind that monitoring and reporting requirements that may be sufficient for government regulators may be insufficient for the public. Government regulators may be satisfied with a regulation that requires a facility to monitor specified parameters (e.g., operating temperature) to generally assure that the facility is operating properly, and to perform a formal compliance test (e.g., measuring actual smokestack emissions) only upon the government's request.

3. Potential to Promote Advances in Data Capture (*e.g.,* ''Check-In App'' With Location and Photos)

One of the advances of the digital age is the ability to ''check-in'' with geospatial accuracy at any location. For example, in the 2012 NSPS, we provided a mechanism by which owners and operators could streamline annual reporting of well completions by using a digital camera to document that a well completion was performed in compliance with the NSPS. In lieu of submitting voluminous hard copies of well completion records in their annual report, the owner or operator could document the completions with a digital photograph of the REC equipment in use, with the date and geospatial coordinates shown on the photographs. These photographs would be submitted digitally or in hard copy form with the next annual report, along with a list of well completions performed with identifying information for each well completed. This option has been referred to as ''REC PIX.'' Building on the success of REC PIX, the EPA would like to explore this opportunity as it relates to advances in data capture to ensure that other compliant practices are in effect. For example, pictures of storage vessels could provide visual evidence of staining related to excess emissions events. As discussed previously, digital pictures and frame captures can help ensure that optical gas imaging for fugitive emissions is being performed properly. The EPA requests

[127] Lori S. Bennear and Sheila M. Olmstead, *Impacts of the ''Right to Know'': Information Disclosure and the Violation of Drinking Water Standards,* 56 J. ENVT'L ECON. & MGMT. 117 (2008) (finding that when larger utilities were required to mail annual Consumer Confidence Reports on water-supplier compliance pursuant to the 1998 Safe Drinking Water Act amendments, those utilities' total violations were reduced by 30–44% and more severe health violations by 40–57%).

[128] Using a micro-level data set linking Toxic Release Inventory (TRI) releases to plant-level Census data, one researcher found, among other things, that state and local government use of TRI disclosures helped induce firms to become cleaner. Linda T.M. Bui, *Public Disclosure of Private Information as a Tool for Regulating Environmental Emissions: Firm-Level Responses by Petroleum Refineries to the Toxics Release Inventory* (Brandeis Univ. Working Paper Series, Working Paper No. 05–13, 2005), available at *ftp://ftp2.census.gov/ces/wp/2005/CES-WP-05-13.pdf.* See also, Shameek Komar & Mark A. Cohen, *Information As Regulation: The Effect of Community Right to Know Laws on Toxic Emissions,* 32 J. ENVT'L ECON. & MGMT. 109 (1997), available at *http://www.sciencedirect.com/science/article/pii/S0095069696909559* (finding that the top 40 firms with the largest drop in stock price following their disclosure of TRI emissions subsequently reduced their average emissions more than other firms in their industry, including the top 40 firms with the largest TRI emissions per thousand dollars in revenue [TRI/$]; these firms both significantly reduced their average emissions and made significant attempts to improve their environmental performance by reducing the frequency and severity of chemical and oil spills).

[129] DAVID WHEELER, WORLD BANK REPORT NO. 16513–BR, INFORMATION IN POLLUTION MANAGEMENT: THE NEW MODEL 14 (1997), available at *http://web.worldbank.org/archive/website01004/WEB/IMAGES/BRAZILIN.PDF* (finding that Indonesia's Program for Pollution Control, Evaluation and Rating improved the studied facilities' ratings pursuant to a color-coded scheme).

[130] In 1990, the Ministry of Environment, Lands and Parks of British Columbia, Canada (MOE) employed a public disclosure strategy releasing a list of industrial operations that were not in compliance with their waste management permits or were deemed to be a potential pollution concern. Simultaneously, the Government of British Columbia introduced revised regulations to its pulp and paper regulations setting stricter standards and also increasing the maximum amount of fines under the Waste Management Act. Results indicated that the public disclosure strategy had a larger impact on both emissions levels and compliance status than traditional enforcement strategies, including fines, orders, and penalties. The results also indicated that the adoption of stricter standards and higher penalties also had a significant impact on decreasing emissions levels. Jérôme Foulon et al., *Incentives for Pollution Control: Regulation and Public Disclosure* 5 (World Bank Pol'y Res., Working Paper No. 2291, 2000), available at *http://papers.ssrn.com/sol3/papers.cfm?abstract_id=629138.*

[131] Richard Liroff, D. F. (2014). *Disclosing the Facts: Transparency and Risk in Hydraulic Fracturing.*

comments on viability and benefits of this approach, and to which areas it might be expanded.

XI. Impacts of This Proposed Rule

A. What are the air impacts?

For this action, the EPA estimated the emission reductions that will occur due to the implementation of the proposed emission limits. The EPA estimated emission reductions based on the control technologies proposed as the BSER. This analysis estimates regulatory impacts for the analysis years of 2020 and 2025. The analysis of 2020 is assumed to represent the first year the full suite of proposed standards is in effect and thus represents a single year of potential impacts. We estimate impacts in 2025 to illustrate how new and modified sources accumulate over time under the proposed NSPS. The regulatory impact estimates for 2025 include sources newly affected in 2025 as well as the accumulation of affected sources from 2020 to 2024 that are also assumed to be in continued operation in 2025, thus incurring compliance costs and emissions reductions in 2025.

While the EPA is proposing an exclusion from fugitive emission requirements for low production well sites, there is uncertainty in how many well sites this exclusion might affect in the future. As a result, the analysis in this RIA presents a ''low'' impact case and ''high'' impact case for fugitive emissions requirements at well sites. The low impact case excludes from analysis an estimate of low production sites, based on the first month of production data from wells newly completed or modified in 2012. The high impact case includes these well sites. National-level results for the proposed NSPS, then, are presented as ranges.

In 2020, we have estimated that the proposed NSPS would reduce about 170,000 to 180,000 tons of methane emissions and 120,000 tons of VOC emissions from affected facilities. In 2025, we have estimated that the proposed NSPS would reduce about 340,000 to 400,000 tons of methane emissions and 170,000 to 180,000 tons of VOC emissions from affected facilities. The NSPS is also expected to concurrently reduce about 310 to 400 tons HAP in 2020 and 1,900 to 2,500 tons HAP in 2025.

As described in the TSD and RIA for this proposal, the EPA projected affected facilities using a combination of historical data from the U.S. GHG Inventory, and projected activity levels, taken from the Energy Information Administration (EIA's) Annual Energy Outlook (AEO). The EPA also considered state regulations with similar requirements to the proposed NSPS in projecting affected sources for impacts analyses supporting this proposed rule. The EPA solicits comments on these projection methods as well as solicits information that would improve our estimate of the turnover rates and rates of modification of relevant sources and the number of wells on multi-well well sites.

B. What are the energy impacts?

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

The proposed NSPS encourages the use of emission controls that recover hydrocarbon products, such as methane that can be used on-site as fuel or reprocessed within the production process for sale. We estimated that the proposed standards will result in a total cost of about $150 to $170 million in 2020 and $320 to $420 million in 2025 (in 2012 dollars).

C. What are the compliance costs?

The EPA estimates the total capital cost of the proposed NSPS will be $170 to $180 million in 2020 and $280 to $330 million in 2025. The estimate of total annualized engineering costs of the proposed NSPS is $180 to $200 million in 2020 and $370 to $500 million in 2025. This annual cost estimate includes the cost of capital, operating and maintenance costs, and monitoring, reporting, and recordkeeping costs. This estimated annual cost does not take into account any producer revenues associated with the recovery of salable natural gas. The EPA estimates that about 8 million Mcf in 2020 and 16 to 19 million Mcf of natural gas in 2025 will be recovered by implementing the proposed NSPS. In the engineering cost analysis, we assume that producers are paid $4 per thousand cubic feet (Mcf) for the recovered gas at the wellhead. After accounting for these revenues, the estimate of total annualized engineering costs of the proposed NSPS are estimated to be $150 to $170 million in 2020 and $320 to $420 million in 2025. The price assumption is influential on estimated annualized engineering costs. A simple sensitivity analysis indicates $1/Mcf change in the wellhead price causes a change in estimated engineering compliance costs of about $8 million in 2020 and $16 to $19 million in 2025.

D. What are the economic and employment impacts?

The EPA used the National Energy Modeling System (NEMS) to estimate the impacts of the proposed rule on the United States energy system. The NEMS is a publically-available model of the United States energy economy developed and maintained by the Energy Information Administration of the DOE and is used to produce the Annual Energy Outlook, a reference publication that provides detailed forecasts of the United States energy economy.

The EPA modeled the high impact case of the proposed NSPS with respect the low production exemption from the well site fugitive emissions requirements. As such the NEMS-based estimates of energy system impacts are likely high end estimates.

The NEMS-based analysis estimates natural gas and crude oil production levels remain essentially unchanged under the proposed rule in 2020, while slight declines are estimated for 2025 for both natural gas (about 4 billion cubic feet (bcf) or about 0.01 percent) and crude oil production (about 2,000 barrels per day or 0.03 percent). Wellhead natural gas prices for onshore lower 48 production are not estimated to change in 2020 under the proposed rule, but are estimated to increase about $0.007 per Mcf or 0.14 percent in 2025. Meanwhile, well crude oil prices for onshore lower 48 production are not estimated to change, despite the incidence of new compliance costs from the proposed NSPS. Meanwhile, net imports of natural gas are estimated to decline slightly in 2020 (by about 1 bcf or 0.05 percent) and in 2025 (by about 3 bcf or 0.09 percent). Crude oil imports are estimated to not change in 2020 and increase by about 1,000 barrels per day (or 0.02 percent) in 2025.

Executive Order 13563 directs federal agencies to consider the effect of regulations on job creation and employment. According to the Executive Order, ''our regulatory system must protect public health, welfare, safety, and our environment while promoting economic growth, innovation, competitiveness, and job creation. It must be based on the best available science.'' (Executive Order 13563, 2011) Although standard benefit-cost analyses have not typically included a separate analysis of regulation-induced employment impacts, we typically conduct employment analyses. During the current economic recovery, employment impacts are of particular concern and questions may arise about their existence and magnitude.

EPA estimated the labor impacts due to the installation, operation, and maintenance of control equipment, control activities, and labor associated with new reporting and recordkeeping requirements. We estimated up-front and continual, annual labor requirements by estimating hours of labor required for compliance and converting this number to full-time equivalents (FTEs) by dividing by 2,080 (40 hours per week multiplied by 52 weeks). The up-front labor requirement to comply with the proposed NSPS is estimated at about 50 to 70 FTEs in 2020 and 50 to 70 FTEs in 2025. The annual labor requirement to comply with proposed NSPS is estimated at about 470 to 530 FTEs in 2020 and 1,100 to 1,400 FTEs in 2025.

We note that this type of FTE estimate cannot be used to identify the specific number of people involved or whether new jobs are created for new employees, versus displacing jobs from other sectors of the economy.

E. What are the benefits of the proposed standards?

The proposed rule is expected to result in significant reductions in emissions. In 2020, the proposed rule is anticipated to reduce 170,000 to 180,000 tons of methane (a GHG and a precursor to global ozone formation), 120,000 tons of VOC (a precursor to both PM (2.5 microns and less) ($PM_{2.5}$) and ozone formation), and 310 to 400 tons of HAP. In 2025, the proposed rule is anticipated to reduce 340,000 to 400,000 tons of methane, 170,000 to 180,000 tons of VOC, and 1,900 to 2,500 tons of HAP. These pollutants are associated with substantial health effects, climate effects, and other welfare effects.

The proposed standards are expected to reduce methane emissions annually by about 3.8 to 4.0 million metric tons CO_2 Eq. in 2020 and by about 7.7 to 9.0 million metric tons CO_2 Eq. in 2025. The methane reductions represent about 2 percent in 2020 and 4 to 5 percent in 2025 of the baseline methane emissions for this sector reported in the U.S. GHG Inventory for 2013 (about 182 million metric tons CO_2 Eq. when petroleum refineries and petroleum transportation are excluded because these sources are not examined in this proposal). However, it is important to note that the emission reductions are based upon predicted activities in 2020 and 2025; the EPA did not forecast sector-level emissions in 2020 and 2025 for this rulemaking.

Methane is a potent GHG that, once emitted into the atmosphere, absorbs terrestrial infrared radiation that contributes to increased global warming and continuing climate change. Methane reacts in the atmosphere to form tropospheric ozone and stratospheric water vapor, both of which also contribute to global warming. When accounting for the impacts changing methane, tropospheric ozone, and stratospheric water vapor concentrations, the Intergovernmental Panel on Climate Change (IPCC) 5th Assessment Report (2013) found that historical emissions of methane accounted for about 30 percent of the total current warming influence (radiative forcing) due to historical emissions of GHGs. Methane is therefore a major contributor to the climate change impacts described previously. In 2013, total methane emissions from the oil and natural gas industry represented nearly 29 percent of the total methane emissions from all sources and account for about 3 percent of all CO_2-equivalent emissions in the United States, with the combined petroleum and natural gas systems being the largest contributor to U.S. anthropogenic methane emissions.

We calculated the global social benefits of methane emission reductions expected from the proposed NSPS standards for oil and natural gas sites using estimates of the social cost of methane (SC-CH_4), a metric that estimates the monetary value of impacts associated with marginal changes in methane emissions in a given year. The SC-CH_4 estimates applied in this analysis were developed by Marten et al. (2014) and are discussed in greater detail below.

A similar metric, the social cost of CO_2 (SC-CO_2), provides important context for understanding the Marten et al. SC-CH_4 estimates.[132] The SC-CO_2 is a metric that estimates the monetary value of impacts associated with marginal changes in CO_2 emissions in a given year. Similar to the SC-CH_4, it includes a wide range of anticipated climate impacts, such as net changes in agricultural productivity, property damage from increased flood risk, and changes in energy system costs, such as reduced costs for heating and increased costs for air conditioning. Estimates of the SC-CO_2 have been used by the EPA and other federal agencies to value the impacts of CO_2 emissions changes in benefit cost analysis for GHG-related rulemakings since 2008.

The SC-CO_2 estimates were developed over many years, using the best science available, and with input from the public. Specifically, an interagency working group (IWG) that included EPA and other executive branch agencies and offices used three integrated assessment models (IAMs) to develop the SC-CO_2 estimates and recommended four global values for use in regulatory analyses. The SC-CO_2 estimates were first released in February 2010 and updated in 2013 using new versions of each IAM. The 2010 SC-CO_2 Technical Support Document (2010 TSD) provides a complete discussion of the methods used to develop these estimates and the current SC-CO_2 TSD presents and discusses the 2013 update (including recent minor technical corrections to the estimates).[133]

The SC-CO_2 TSDs discuss a number of limitations to the SC-CO_2 analysis, including the incomplete way in which the IAMs capture catastrophic and non-catastrophic impacts, their incomplete treatment of adaptation and technological change, uncertainty in the extrapolation of damages to high temperatures, and assumptions regarding risk aversion. Currently, IAMs do not assign value to all of the important physical, ecological, and economic impacts of climate change recognized in the climate change literature due to a lack of precise information on the nature of damages and because the science incorporated into these models understandably lags behind the most recent research. Nonetheless, these estimates and the discussion of their limitations represent the best available information about the social benefits of CO_2 reductions to inform benefit-cost analysis. EPA and other agencies continue to engage in research on modeling and valuation of climate impacts with the goal to improve these estimates, and continue to consider feedback on the SC-CO_2 estimates from stakeholders through a range of channels, including public comments on Agency rulemakings a separate recent OMB public comment solicitation, and through regular interactions with stakeholders and research analysts implementing the SC-CO_2 methodology. See the RIA of this rule for additional details.

A challenge particularly relevant to this proposal is that the IWG did not estimate the social costs of non-CO_2 GHG emissions at the time the SC-CO_2

[132] Previous analyses have commonly referred to the social cost of carbon dioxide emissions as the social cost of carbon or SCC. To more easily facilitate the inclusion of non-CO_2 GHGs in the discussion and analysis the more specific SC-CO_2 nomenclature is used to refer to the social cost of CO_2 emissions.

[133] Both the 2010 SC-CO_2 TSD and the current TSD are available at: *https://www.whitehouse.gov/omb/oira/social-cost-of-carbon.*

estimates were developed. In addition, the directly modeled estimates of the social costs of non-CO_2 GHG emissions previously found in the published literature were few in number and varied considerably in terms of the models and input assumptions they employed[134] (EPA 2012). As a result, benefit-cost analyses informing U.S. federal rulemakings to date have not fully considered the monetized benefits associated with CH_4 emissions mitigation. To understand the potential importance of monetizing non-CO_2 GHG emissions changes, EPA has conducted sensitivity analysis in some of its past regulatory analyses using an estimate of the GWP of CH_4 to convert emission impacts to CO_2 equivalents, which can then be valued using the SC-CO_2 estimates. This approach approximates the social cost of methane (SC-CH_4) using estimates of the SC-CO_2 and the GWP of CH_4.[135]

The published literature documents a variety of reasons that directly modeled estimates of SC-CH_4 are an analytical improvement over the estimates from the GWP approximation approach. Specifically, several recent studies found that GWP-weighted benefit estimates for methane are likely to be lower than the estimates derived using directly modeled social cost estimates for these gases.[136] The GWP reflects only the relative integrated radiative forcing of a gas over 100 years in comparison to CO_2. The directly modeled social cost estimates differ from the GWP-scaled SC-CO_2 because the relative differences in timing and magnitude of the warming between gases are explicitly modeled, the non-linear effects of temperature change on economic damages are included, and rather than treating all impacts over a hundred years equally, the modeled damages over the time horizon considered (2300 in this case) are discounted to present value terms. A detailed discussion of the limitations of the GWP approach can be found in the RIA.

In general, the commenters on previous rulemakings strongly encouraged the EPA to incorporate the monetized value of non-CO_2 GHG impacts into the benefit cost analysis. However they noted the challenges associated with the GWP approach, as discussed above, and encouraged the use of directly modeled estimates of the SC-CH_4 to overcome those challenges.

Since then, a paper by Marten et al. (2014) has provided the first set of published SC-CH_4 estimates in the peer-reviewed literature that are consistent with the modeling assumptions underlying the SC-CO_2 estimates.[137][138] Specifically, the estimation approach of Marten et al. used the same set of three IAMs, five socioeconomic and emissions scenarios, equilibrium climate sensitivity distribution, three constant discount rates, and aggregation approach used by the IWG to develop the SC-CO_2 estimates.

The SC-CH_4 estimates from Marten et al. (2014) are presented below in Table 6. More detailed discussion of the SC-CH_4 estimation methodology, results and a comparison to other published estimates can be found in the RIA and in Marten et al.

TABLE 6—SOCIAL COST OF CH_4, 2012–2050[a]

[In 2012$ per metric ton] (Source: Marten et al., 2014[b])

Year	SC-CH_4			
	5% Average	3% Average	2.5% Average	3% 95th Percentile
2012	$430	$1000	$1400	$2800
2015	490	1100	1500	3000
2020	580	1300	1700	3500
2025	700	1500	1900	4000
2030	820	1700	2200	4500
2035	970	1900	2500	5300
2040	1100	2200	2800	5900
2045	1300	2500	3000	6600
2050	1400	2700	3300	7200

Notes:

[a] There are four different estimates of the SC-CH_4, each one emissions-year specific. The first three shown in the table are based on the average SC-CH_4 from three integrated assessment models at discount rates of 5, 3, and 2.5 percent. The fourth estimate is the 95th percentile of the SC-CH_4 across all three models at a 3 percent discount rate. See RIA for details.

[b] The estimates in this table have been adjusted to reflect the minor technical corrections to the SC-CO_2 estimates described above. See the Corrigendum to Marten et al. (2014), *http://www.tandfonline.com/doi/abs/10.1080/14693062.2015.1070550*.

The application of these directly modeled SC-CH_4 estimates from Marten et al. (2014) in a benefit-cost analysis of a regulatory action is analogous to the use of the SC-CO_2 estimates. In addition, the limitations for the SC-CO_2 estimates discussed above likewise apply to the SC-CH_4 estimates, given the consistency in the methodology.

The EPA recently conducted a peer review of the application of the Marten et al. (2014) non-CO_2 social cost estimates in regulatory analysis and received responses that supported this application. See the RIA for a detailed discussion.

In light of the favorable peer review and past comments urging the EPA to

[134] U.S. EPA. 2012. Regulatory Impact Analysis Final New Source Performance Standards and Amendments to the National Emissions Standards for Hazardous Air Pollutants for the Oil and Natural Gas Industry. Office of Air Quality Planning and Standards, Health and Environmental Impacts Division. April. *http://www.epa.gov/ttn/ecas/regdata/RIAs/oil_natural_gas_final_neshap_nsps_ria.pdf.* Accessed March 30, 2015.

[135] For example, see (1) U.S. EPA. (2012). ''Regulatory impact analysis supporting the 2012 U.S. Environmental Protection Agency final new source performance standards and amendments to the national emission standards for hazardous air pollutants for the oil and natural gas industry.'' Retrieved from *http://www.epa.gov/ttn/ecas/regdata/RIAs/oil_natural_gas_final_neshap_nsps_ria.pdf* and (2) U.S. EPA. (2012). ''Regulatory impact analysis: Final rulemaking for 2017-2025 light-duty vehicle greenhouse gas emission standards and corporate average fuel economy standards.'' Retrieved from *http://www.epa.gov/otaq/climate/documents/420r12016.pdf.*

[136] See Waldhoff et al. (2011); Marten and Newbold (2012); and Marten et al. (2014).

[137] Marten et al. (2014) also provided the first set of SC-N_2O estimates that are consistent with the assumptions underlying the IWG SC-CO_2 estimates.

[138] Marten, A.L., E.A. Kopits, C.W. Griffiths, S.C. Newbold & A. Wolverton (2014, online publication; 2015, print publication). Incremental CH_4 and N_2O mitigation benefits consistent with the U.S. Government's SC-CO_2 estimates, Climate Policy, DOI: 10.1080/14693062.2014.912981.

value non-CO_2 GHG impacts in its rulemakings, the Agency has used the Marten et al. (2014) SC-CH_4 estimates to value methane impacts expected from this proposed rulemaking and has included those benefits in the main benefits analysis. The EPA seeks comments on the use of these directly modeled estimates, from the peer-reviewed literature, for the social cost of non-CO_2 GHGs in today's rulemaking.

The methane benefits calculated using Marten et al. (2014) are presented for years 2020 and 2025. Applying this approach to the methane reductions estimated for the NSPS proposal, the 2020 methane benefits vary by discount rate and range from about $88 million to approximately $550 million; the mean SC-CH_4 at the 3-percent discount rate results in an estimate of about $200 to $210 million in 2020. The methane benefits increase in the 2025, ranging from $220 million to $1.4 billion, depending on discount rate used; the mean SC-CH_4 at the 3-percent discount rate results in an estimate of about $460 to $550 million in 2025.

TABLE 7—ESTIMATED GLOBAL BENEFITS OF METHANE REDUCTIONS

[In millions, 2012$]

Discount rate and statistic	Year	
	2020	2025
Million metric tonnes of methane reduced	0.15 to 0.16	0.31 to 0.36.
Million metric tonnes of CO_2 Eq.	3.8 to 4.0	7.7 to 9.0.
5% (average)	$88 to $93	$220 to $250.
3% (average)	$200 to $210	$460 to $550.
2.5% (average)	$260 to $280	$600 to $700.
3% (95th percentile)	$520 to $550	$1,200 to $1,400.

In addition to the limitation discussed above, and the referenced documents, there are additional impacts of individual GHGs that are not currently captured in the IAMs used in the directly modeled approach of Marten et al. (2014), and therefore not quantified for the rule. For example, in addition to being a GHG, methane is a precursor to ozone. The ozone generated by methane has important non-climate impacts on agriculture, ecosystems, and human health. The RIA describes the specific impacts of methane as an ozone precursor in more detail and discusses studies that have estimated monetized benefits of these methane generated ozone effects. The EPA continues to monitor developments in this area of research and seeks comment on the potential inclusion of health impacts of ozone generated by methane in future regulatory analysis.

With the data available, we are not able to provide credible health benefit estimates for the reduction in exposure to HAP, ozone and $PM_{2.5}$ for these rules, due to the differences in the locations of oil and natural gas emission points relative to existing information and the highly localized nature of air quality responses associated with HAP and VOC reductions. This is not to imply that there are no benefits of the rules; rather, it is a reflection of the difficulties in modeling the direct and indirect impacts of the reductions in emissions for this industrial sector with the data currently available.[139] In addition to health improvements, there will be improvements in visibility effects, ecosystem effects and climate effects, as well as additional product recovery.

Although we do not have sufficient information or modeling available to provide quantitative estimates for this rulemaking, we include a qualitative assessment of the health effects associated with exposure to HAP, ozone and $PM_{2.5}$ in the RIA for this rule. These qualitative effects are briefly summarized below, but for more detailed information, please refer to the RIA, which is available in the docket. One of the HAPs of concern from the oil and natural gas sector is benzene, which is a known human carcinogen. VOC emissions are precursors to both $PM_{2.5}$ and ozone formation. As documented in previous analyses (U.S. EPA, 2006,[140] U.S. EPA, 2010,[141] and U.S. EPA, 2014 [142]), exposure to $PM_{2.5}$ and ozone is associated with significant public health effects. $PM_{2.5}$ is associated with health effects, including premature mortality for adults and infants, cardiovascular morbidity such as heart attacks, and respiratory morbidity such as asthma attacks, acute bronchitis, hospital admissions and emergency room visits, work loss days, restricted activity days and respiratory symptoms, as well as visibility impairment.[143] Ozone is associated with health effects, including hospital and emergency department visits, school loss days and premature mortality, as well as injury to vegetation and climate effects.[144]

Finally, the control techniques to meet the standards are anticipated to have minor secondary emissions impacts, which may partially offset the direct benefits of this rule. The magnitude of these secondary air pollutant impacts is small relative to the

[139] Previous studies have estimated the monetized benefits-per-ton of reducing VOC emissions associated with the effect that those emissions have on ambient $PM_{2.5}$ levels and the health effects associated with $PM_{2.5}$ exposure (Fann, Fulcher, and Hubbell, 2009). While these ranges of benefit-per-ton estimates can provide useful context, the geographic distribution of VOC emissions from the oil and gas sector are not consistent with emissions modeled in Fann, Fulcher, and Hubbell (2009). In addition, the benefit-per-ton estimates for VOC emission reductions in that study are derived from total VOC emissions across all sectors. Coupled with the larger uncertainties about the relationship between VOC emissions and $PM_{2.5}$ and the highly localized nature of air quality responses associated with HAP and VOC reductions, these factors lead us to conclude that the available VOC benefit-per-ton estimates are not appropriate to calculate monetized benefits of these rules, even as a bounding exercise.

[140] U.S. EPA. *RIA. National Ambient Air Quality Standards for Particulate Matter,* Chapter 5. Office of Air Quality Planning and Standards, Research Triangle Park, NC. October 2006. Available on the Internet at *http://www.epa.gov/ttn/ecas/regdata/RIAs/Chapter%205-Benefits.pdf.*

[141] U.S. EPA. *RIA. National Ambient Air Quality Standards for Ozone.* Office of Air Quality Planning and Standards, Research Triangle Park, NC. January 2010. Available on the Internet at *http://www.epa.gov/ttn/ecas/regdata/RIAs/s1-supplemental_analysis_full.pdf.*

[142] U.S. EPA. *RIA. National Ambient Air Quality Standards for Ozone.* Office of Air Quality Planning and Standards, Research Triangle Park, NC. December 2014. Available on the Internet at *http://www.epa.gov/ttnecas1/regdata/RIAs/20141125ria.pdf.*

[143] U.S. EPA. *Integrated Science Assessment for Particulate Matter (Final Report).* EPA–600–R–08–139F. National Center for Environmental Assessment—RTP Division. December 2009. Available at *http://cfpub.epa.gov/ncea/cfm/recordisplay.cfm?deid=216546.*

[144] U.S. EPA. *Air Quality Criteria for Ozone and Related Photochemical Oxidants (Final).* EPA/600/R–05/004aF–cF. Washington, DC: U.S. EPA. February 2006. Available on the Internet at *http://cfpub.epa.gov/ncea/CFM/recordisplay.cfm?deid=149923.*

direct emission reductions anticipated from this rule.

In particular, EPA has estimated that an increase in flaring of methane in response to this rule will produce a variety of emissions, including 610,000 tons of CO_2 in 2020 and 750,000 tons of CO_2 in 2025. EPA has not estimated the monetized value of the secondary emissions of CO_2 because much of the methane that would have been released in the absence of the flare would have eventually oxidized into CO_2 in the atmosphere. Note that the CO_2 produced from the methane oxidizing in the atmosphere is not included in the calculation of the SC-CH_4. However, EPA recognizes that because the growth rate of the SC-CO_2 estimates are lower than their associated discount rates, the estimated impact of CO_2 produced in the future from oxidized methane would be less than the estimated impact of CO_2 released immediately from flaring, which would imply a small disbenefit associated with flaring. Assuming an average methane oxidation period of 8.7 years, consistent with the lifetime used in IPCC AR4, the disbenefits associated with destroying one ton of methane and releasing the CO_2 emissions in 2020 instead of being released in the future via the methane oxidation process is estimated to be $6 to $25, depending on the SC-$CO_2$ value or 0.7 percent to 1.0 percent of the SC-CH_4 estimates for 2020. The analogous estimates for 2025 are $7 to $34 or 0.8 percent to 1.0 percent of the SC-CH_4 estimates for 2025. While EPA is not accounting for the CO_2 disbenefits at this time, we request comment on the appropriateness of the monetization of such impacts using the SC-CO_2 and aspects of the calculation. See RIA for further details about the calculation.

XII. Statutory and Executive Order Reviews

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

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

This action is an economically significant regulatory action that was submitted to the OMB for review. Any changes made in response to OMB recommendations have been documented in the docket. The EPA prepared an analysis of the potential costs and benefits associated with this action.

In addition, the EPA prepared a Regulatory Impact Analysis (RIA) of the potential costs and benefits associated with this action. The RIA available in the docket describes in detail the empirical basis for the EPA's assumptions and characterizes the various sources of uncertainties affecting the estimates below. Table 8 shows the results of the cost and benefits analysis for these proposed rules.

TABLE 8—SUMMARY OF THE MONETIZED BENEFITS, SOCIAL COSTS AND NET BENEFITS FOR THE PROPOSED OIL AND NATURAL GAS NSPS IN 2020 AND 2025

[Millions of 2012$]

	2020	2025
Total Monetized Benefits [1]	$200 to $210 million	$460 to $550 million.
Total Costs [2]	$150 to $170 million	$320 to $420 million.
Net Benefits [3]	$35 to $42 million	$120 to $150 million.
Non-monetized Benefits	Non-monetized climate benefits. Health effects of $PM_{2.5}$ and ozone exposure from 120,000 tons of VOC in 2020 and 170,000 to 180,000 tons of VOC in 2025. Health effects of HAP exposure from 310 to 400 tons of HAP in 2020 and 1,900 to 2,500 tons of HAP in 2025. Health effects of ozone exposure from 170,000 to 180,000 tons of methane in 2020 and 340,000 to 400,000 tons methane in 2025. Visibility impairment. Vegetation effects.	

[1] We estimate methane benefits associated with four different values of a one ton CH_4 reduction (model average at 2.5 percent discount rate, 3 percent, and 5 percent; 95th percentile at 3 percent). For the purposes of this table, we show the benefits associated with the model average at 3 percent discount rate, however we emphasize the importance and value of considering the full range of social cost of methane values. We provide estimates based on additional discount rates in preamble section XI and in the RIA. Also, the specific control technologies for the proposed NSPS are anticipated to have minor secondary disbenefits. The net CO_2-equivalent (CO_2 Eq.) methane emission reductions are 3.8 to 4.0 million metric tons in 2020 and 7.7 to 9.0 million metric tons in 2025.

[2] The engineering compliance costs are annualized using a 7 percent discount rate and include estimated revenue from additional natural gas recovery as a result of the NSPS. When rounded, the cost estimates are the same for the 3 percent discount rate as they are for the 7 percent discount rate cost estimates, so rounded net benefits do not change when using a 3 percent discount rate.

[3] Figures may not sum due to rounding.

B. Paperwork Reduction Act (PRA)

The Office of Management and Budget (OMB) has previously approved the information collection activities contained in 40 CFR part 60, subpart OOOO under the PRA and has assigned OMB control number 2060–0673 and ICR number 2437.01; a summary can be found at 77 FR 49537. The information collection requirements in today's proposed rule titled, Standards of Performance for Crude Oil and Natural Gas Facilities for Construction, Modification, or Reconstruction (40 CFR part 60 subpart OOOOa) have been submitted for approval to the OMB under the PRA. The ICR document prepared by the EPA has been assigned EPA ICR Number 2523.01. You can find a copy of the ICR in the docket for this rule, and is briefly summarized below.

The information to be collected for the proposed NSPS is based on notification, performance tests, recordkeeping and reporting requirements which will be mandatory for all operators subject to the final standards. Recordkeeping and reporting requirements are specifically authorized by section 114 of the CAA (42 U.S.C. 7414). The information will be used by the delegated authority (state agency, or Regional Administrator if there is no delegated state agency) to ensure that the standards and other requirements are being achieved. Based on review of the recorded information at the site and the reported information, the delegated permitting authority can identify facilities that may not be in compliance and decide which facilities, records, or processes may need inspection. All information submitted to the EPA pursuant to the recordkeeping and reporting requirements for which a claim of confidentiality is made is safeguarded according to Agency policies set forth in 40 CFR part 2, subpart B.

Potential respondents under subpart OOOOa are owners or operators of new, modified or reconstructed oil and natural gas affected facilities as defined under the rule. None of the facilities in the United States are owned or operated by state, local, tribal or the Federal government. All facilities are privately owned for-profit businesses. The requirements in this action result in industry recording keeping and reporting burden associated with review of the requirements for all affected entities, gathering relevant information, performing initial performance tests and repeat performance tests if necessary, writing and submitting the notifications and reports, developing systems for the purpose of processing and maintaining information, and train personnel to be able to respond to the collection of information.

The estimated average annual burden (averaged over the first 3 years after the effective date of the standards) for the recordkeeping and reporting requirements in subpart OOOOa for the 2,552 owners and operators that are subject to the rule is 92,658 labor hours, with an annual average cost of $3,163,699. The annual public reporting and recordkeeping burden for this collection of information is estimated to average 3.9 hours per response. Respondents must monitor all specified criteria at each affected facility and maintain these records for 5 years. Burden is defined at 5 CFR 1320.3(b).

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

Submit your comments on the Agency's need for this information, the accuracy of the provided burden estimates and any suggested methods for minimizing respondent burden to the EPA using the docket identified at the beginning of this rule. You may also send your ICR-related comments to OMB's Office of Information and Regulatory Affairs via email to *RIA_submissions@omb.eop.gov,* Attention: Desk Officer for the EPA. Since OMB is required to make a decision concerning the ICR between 30 and 60 days after receipt, OMB must receive comments no later than November 17, 2015. The EPA will respond to any ICR-related comments in the final rule.

C. Regulatory Flexibility Act (RFA)

The RFA generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small organizations, and small governmental jurisdictions.

For purposes of assessing the impacts of this rule on small entities, a small entity is defined as: (1) A small business in the oil or natural gas industry whose parent company has no more than 500 employees (or revenues of less than $7 million for firms that transport natural gas via pipeline); (2) a small governmental jurisdiction that is a government of a city, county, town, school district, or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.

Pursuant to section 603 of the RFA, the EPA prepared an initial regulatory flexibility analysis (IRFA) that examines the impact of the proposed rule on small entities along with regulatory alternatives that could minimize that impact. The complete IRFA is available for review in the docket and is summarized here.

The IRFA describes the reason why the proposed rule is being considered and describes the objectives and legal basis of the proposed rule, as well as discusses related rules affecting the oil and natural gas sector. The IRFA describes the EPA's examination of small entity effects prior to proposing a regulatory option and provides information about steps taken to minimize significant impacts on small entities while achieving the objectives of the rule.

The EPA also summarized the potential regulatory cost impacts of the proposed rule and alternatives in Section 3 of the RIA. The analysis in the IRFA drew upon the same analysis and assumptions as the analyses presented in the RIA. The IRFA analysis is presented in its entirely in Section 7.3 of the RIA.

Identifying impacts on specific entities is challenging because of the difficulty of predicting potentially affected new or modified sources at the firm level. To identify potentially affected entities under the proposed NSPS, the EPA combined information from industry databases to identify firms drilling and completing wells in 2012, as well as identified their oil and natural gas production levels for that year.

The EPA based the analysis in the IRFA on impacts estimates for the proposed requirements for hydraulically fractured and re-fractured oil well completions and well site fugitive emissions. While the IRFA does not incorporate potential impacts from other provisions of the proposed NSPS, the completions and fugitive emissions provisions represent a large majority of the estimated compliance costs of the proposed NSPS in 2020 and 2025. Note incorporating impacts from other provisions in this analysis is a limitation and underestimates impacts, but the EPA believes that detailed analysis of the two provisions impacts on small entities is illustrative of impacts on small entities from the proposed rule in its entirety.

We projected the 2012 base year estimates of incrementally affected facilities to 2020 and 2025 levels based on the same growth rates used to project future activities as described in the TSD and consistent with other analyses in the RIA. This approach assumes that no other firms perform potentially affected activities and firms performing oil and natural gas activities in 2012 will continue to do so in 2020 and 2025. While likely true for many firms, this will not be the case for all firms.

For some firms, we estimated their 2012 sales levels by multiplying 2012 oil and natural gas production levels reported in an industry database by assumed oil and natural gas prices at the wellhead. For natural gas, we assumed the $4/Mcf for natural gas. For oil prices, we estimated revenues using two alternative prices, $70/bbl and $50/bbl. In the results, we call the case using $70/bbl the ''primary scenario'' and the case using the $50/bbl as the ''low oil price scenario''.

For projected 2020 and 2025 potentially affected activities, we allocated compliance costs across entities based upon the costs estimated in the TSD and used in the RIA. The RIA and IRFA also estimates the potential implications of the proposed exclusion for low producing sites from the fugitive emission requirements. Fewer sites in the program due to this exclusion will likely lead to lower costs and emissions.

The analysis indicates about 1,200 to 2,100 small entities may be subject to the requirements for hydraulically fractured and re-fractured oil well completions and fugitive emissions requirements at well sites. The low end of this range reflects an estimate of how many entities might be excluded as a result of the low production fugitive emissions exemption. Also the cost-to-sales ratios with ratios greater than 1 percent and 3 percent increase from 2020 to 2025 as affected sources accumulate under the proposed NSPS. Cost-to-sales ratios exceeding 1 percent and 3 percent are also reduced from the case without the entities that might be excluded from fugitive emissions requirements as a result of the low production exemption.

The analysis above is subject to a number of caveats and limitations. These are discussed in detail in the IRFA, as well as in Section 3 of the RIA. As required by section 609(b) of the RFA, the EPA also convened a Small Business Advocacy Review (SBAR) Panel to obtain advice and recommendations from small entity representatives that potentially would be subject to the rule's requirements. The SBAR Panel evaluated the assembled materials and small-entity comments on issues related to elements of an IRFA. A copy of the full SBAR Panel Report is available in the rulemaking docket.

D. Unfunded Mandates Reform Act (UMRA)

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

E. Executive Order 13132: Federalism

This action does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government. These final rules primarily affect private industry and would not impose significant economic costs on state or local governments.

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

This action has tribal implications. However, it will neither impose substantial direct compliance costs on federally recognized tribal governments, nor preempt tribal law. The majority of the units impacted by this rulemaking on tribal lands are owned by private entities, and tribes will not be directly impacted by the compliance costs associated with this rulemaking. There would only be tribal implications associated with this rulemaking in the case where a unit is owned by a tribal government or a tribal government is given delegated authority to enforce the rulemaking.

The EPA consulted with tribal officials under the ''EPA Policy on Consultation and Coordination with Indian Tribes'' early in the process of developing this regulation to permit them to have meaningful and timely input into its development. Additionally, the EPA has conducted meaningful involvement with tribal stakeholders throughout the rulemaking process. We provided an update on the methane strategy on the January 29, 2015, NTAA and EPA Air Policy call. As required by section 7(a), the EPA's Tribal Consultation Official has certified that the requirements of the Executive Order have been met in a meaningful and timely manner. A copy of the certification is included in the docket for this action.

Consistent with previous actions affecting the oil and natural gas sector, there is significant tribal interest because of the growth of the oil and natural gas production in Indian country. The EPA specifically solicits additional comment on this proposed action from tribal officials.

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

This action is subject to Executive Order 13045 (62 FR 19885, April 23, 1997) because it is an economically significant regulatory action as defined by Executive Order 12866, and the EPA believes that the environmental health or safety risk addressed by this action has a disproportionate effect on children. Accordingly, the agency has evaluated the environmental health and welfare effects of climate change on children.

GHGs including methane contribute to climate change and are emitted in significant quantities by the oil and gas sector. The EPA believes that the GHG emission reductions resulting from implementation of these final guidelines will further improve children's health.

The assessment literature cited in the EPA's 2009 Endangerment Finding concluded that certain populations and life stages, including children, the elderly, and the poor, are most vulnerable to climate-related health effects. The assessment literature since 2009 strengthens these conclusions by providing more detailed findings regarding these groups' vulnerabilities and the projected impacts they may experience.

These assessments describe how children's unique physiological and developmental factors contribute to making them particularly vulnerable to climate change. Impacts to children are expected from heat waves, air pollution, infectious and waterborne illnesses, and mental health effects resulting from extreme weather events. In addition, children are among those especially susceptible to most allergic diseases, as well as health effects associated with heat waves, storms, and floods. Additional health concerns may arise in low income households, especially those with children, if climate change reduces food availability and increases prices, leading to food insecurity within households.

More detailed information on the impacts of climate change to human health and welfare is provided in Section V of this preamble.

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

Executive Order 13211 (66 FR 28355, May 22, 2001) provides that agencies will prepare and submit to the Administrator of the Office of Information and Regulatory Affairs, Office of Management and Budget, a Statement of Energy Effects for certain actions identified as ''significant energy actions.'' Section 4(b) of Executive Order 13211 defines ''significant energy actions'' as any action by an agency (normally published in the **Federal Register**) that promulgates or is expected to lead to the promulgation of a final rule or regulation, including notices of inquiry, advance notices of proposed rulemaking, and notices of proposed rulemaking: (1)(i) That is a significant regulatory action under Executive Order 12866 or any successor order, and (ii) is likely to have a significant adverse effect on the supply, distribution, or use of energy; or (2) that is designated by the Administrator of the Office of Information and Regulatory Affairs as a significant energy action.

This action is not a ''significant energy action'' as defined in Executive Order 13211 (66 FR 28355, May 22, 2001), because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy. The basis for these determinations follows.

The EPA used the National Energy Modeling System (NEMS) to estimate the impacts of the proposed rule on the United States energy system. The NEMS is a publically-available model of the United States energy economy developed and maintained by the Energy Information Administration of the DOE and is used to produce the Annual Energy Outlook, a reference publication that provides detailed forecasts of the United States energy economy.

The EPA modeled the high impact case of the proposed NSPS with respect the low production exemption from the well site fugitive emissions requirements. As such the NEMS-based estimates of energy system impacts are likely high end estimates.

The NEMS-based analysis estimates natural gas and crude oil production levels remain essentially unchanged under the proposed rule in 2020, while slight declines are estimated for 2020 for both natural gas (about 4 billion cubic feet (bcf) or about 0.01 percent) and crude oil production (about 2,000 barrels per day or 0.03 percent). Wellhead natural gas prices for onshore lower 48 production are not estimated to change in 2020 under the proposed rule, but are estimated to increase about $0.007 per Mcf or 0.14 percent in 2025. Meanwhile, well crude oil prices for onshore lower 48 production are not estimated to change, despite the incidence of new compliance costs from the proposed NSPS. Meanwhile, net imports of natural gas are estimated to decline slightly in 2020 (by about 1 bcf or 0.05 percent) and in 2025 (by about 3 bcf or 0.09 percent). Crude oil imports are estimated to not change in 2020 and increase by about 1,000 barrels per day (or 0.02 percent) in 2025.

Additionally, the NSPS establishes several performance standards that give regulated entities flexibility in determining how to best comply with the regulation. In an industry that is geographically and economically heterogeneous, this flexibility is an important factor in reducing regulatory burden. For more information on the estimated energy effects of this proposed rule, please see the Regulatory Impact Analysis which is in the docket for this proposal.

I. National Technology Transfer and Advancement Act (NTTAA) and 1 CFR Part 51

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 (NTTAA), Public Law 104–113 (15 U.S.C. 272 note) directs the EPA to use voluntary consensus standards (VCS) in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. VCS are technical standards (*e.g.*, materials specifications, test methods, sampling procedures, and business practices) that are developed or adopted by VCS bodies. NTTAA directs the EPA to provide Congress, through OMB, explanations when the Agency decides not to use available and applicable VCS.

The proposed rule involves technical standards. Therefore, the EPA conducted searches for the Oil and Natural Gas Sector: Emission Standards for New and Modified Sources through the Enhanced National Standards Systems Network (NSSN) Database managed by the American National Standards Institute (ANSI). Searches were conducted for EPA Methods 1, 1A, 2, 2A, 2C, 2D, 3A, 3B, 3C, 4, 6, 10, 15, 16, 16A, 21, 22, and 25A of 40 CFR part 60 Appendix A. No applicable voluntary consensus standards were identified for EPA Methods 1A, 2A, 2D, 21, and 22. All potential standards were reviewed to determine the practicality of the VCS for this rule. In this rule, the EPA is proposing to include in a final EPA rule regulatory text for 40 CFR part 60, subpart OOOOa that includes incorporation by reference. In accordance with requirements of 1 CFR 51.5, the EPA is proposing to incorporate by reference ASME/ANSI PTC 19–10–1981 Part 10 (2010), ''Flue and Exhaust Gas Analyses'' to be used in lieu of EPA Methods 3B, 6, 6A, 6B, 15A and 16A manual portions only and not the instrumental portion. This standard includes manual and instructional methods of analysis for carbon dioxide, carbon monoxide, hydrogen sulfide, nitrogen oxides, oxygen, and sulfur dioxide. This standard is available from the American Society of Mechanical Engineers (ASME), Three Park Avenue, New York, NY 10016–5990.

The EPA welcomes comments on this aspect of the proposed rulemaking and, specifically, invites the public to identify potentially-applicable VCS and to explain why such standards should be used in this regulation.

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

The EPA believes the human health or environmental risk addressed by this action will not have potential disproportionately high and adverse human health or environmental effects on minority, low-income or indigenous populations. The EPA has determined this because the rulemaking increases the level of environmental protection for all affected populations without having any disproportionately high and adverse human health or environmental effects on any population, including any minority, low-income or indigenous populations. The EPA has provided meaningful participation opportunities for minority, low-income, indigenous populations and tribes during the pre-proposal period by conducting community calls and webinars. Additionally, the EPA will conduct outreach for communities after the rulemaking is finalized.

List of Subjects in 40 CFR Part 60

Administrative practice and procedure, Air pollution control, Incorporation by reference, Intergovernmental relations, Reporting and recordkeeping.

Dated: August 18, 2015.

Gina McCarthy,

Administrator.

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

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

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

AUTHORITY: 42 U.S.C. 4701, et seq.

Subpart A—[Amended]

■ 2. Section 60.17 is amended by revising paragraph (f)(14)

§ 60.17 Incorporations by reference.

* * * * *

(f) * * *

(14) ASME/ANSI PTC 19.10–1981, Flue and Exhaust Gas Analyses [Part 10, Instruments and Apparatus], (Issued August 31, 1981), IBR approved for §§ 60.56c(b), 60.63(f), 60.106(e), 60.104a(d), (h), (i), and (j), 60.105a(d), (f), and (g), § 60.106a(a), § 60.107a(a), (c), and (d), tables 1 and 3 to subpart EEEE, tables 2 and 4 to subpart FFFF, table 2 to subpart JJJJ, § 60.285a(f), §§ 60.4415(a), 60.2145(s) and (t), 60.2710(s) (t), and (w), 60.2730(q), 60.4900(b), 60.5220(b), tables 1 and 2 to subpart LLLL, tables 2 and 3 to subpart MMMM, §§ 60.5406(c) and 60.5413(b), § 60.5406a(c), § 60.5407a(g), §§ 60.5413a(b) and 60.5413a(d).

Subpart OOOO—Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution for which Construction, Modification or Reconstruction Commenced after August 23, 2011, and on or before September 18, 2015

■ 3. The heading for Subpart OOOO is revised to read as set forth above.

■ 4. Section 60.5360 is revised to read as follows:

§ 60.5360 What is the purpose of this subpart?

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

■ 5. Section 60.5365 is amended by:

■ a. Revising the introductory text; and

■ b. Revising paragraph (h)(4).

The revisions read as follows:

§ 60.5365 Am I subject to this subpart?

You are subject to the applicable provisions of this subpart if you are the owner or operator of one or more of the onshore affected facilities listed in paragraphs (a) through (g) of this section for which you commence construction, modification or reconstruction after August 23, 2011, and on or before September 18, 2015.

* * * * *

(h)* * *

(4) A gas well facility initially constructed after August 23, 2011, and on or before September 18, 2015 is considered an affected facility regardless of this provision.

■ 6. Section 60.5370 is amended by adding paragraph (d) to read as follows:

§ 60.5370 When must I comply with this subpart?

* * * * *

(d) You are deemed to be in compliance with this subpart if you are in compliance with all applicable provisions of subpart OOOOa of this part.

■ 7. Section 60.5411 is amended by: revising paragraphs (a)(3)(i)(A) and (c)(3)(i)(A) to read as follows:

§ 60.5411 What additional requirements must I meet to determine initial compliance for my covers and closed vent systems routing materials from storage vessels and centrifugal compressor wet seal degassing systems?

* * * * *

(a) * * *

(3) * * *

(i) * * *

(A) You must properly install, calibrate, maintain, and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere. Set the flow indicator to trigger an audible alarm, and initiate notification via remote alarm to the nearest field office, when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere. You must maintain records of each time the alarm is activated according to § 60.5420(c)(8).

* * * * *

(c)* * *

(3)* * *

(i) * * *

(A) You must properly install, calibrate, maintain, and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere. Set the flow indicator to trigger an audible alarm and initiate notification via remote alarm to the nearest field office, when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere. You must maintain records of each time the alarm is activated according to § 60.5420(c)(8).

* * * * *

■ 8. Section 60.5412 is amended by:

■ a. Revising paragraphs (a)(1)(ii) and (d)(1) introductory text; and

■ b. Adding paragraph (d)(1)(iv).

The revisions and addition read as follows:

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

* * * * *

(a) * * *

(1) * * *

(ii) You must reduce the concentration of TOC in the exhaust gases at the outlet to the device to a level equal to or less than 600 parts per million by volume as propane on a dry basis corrected to 3 percent oxygen as determined in accordance with the requirements of § 60.5413.

* * * * *

(d) * * *

(1) Each enclosed combustion device (*e.g.*, thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) must be designed to reduce the mass content of VOC emissions by 95.0 percent or greater. You must follow the requirements in paragraphs (d)(1)(i) through (iv) of this section.

* * * * *

(iv) Each combustion control device (*e.g.*, thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) must be designed and operated in accordance with one of the performance requirements specified in paragraphs (A) through (D) of this section.

(A) You must reduce the mass content of methane and VOC in the gases vented to the device by 95.0 percent by weight or greater as determined in accordance with the requirements of § 60.5413.

(B) You must reduce the concentration of TOC in the exhaust gases at the outlet to the device to a level equal to or less than 600 parts per million by volume as propane on a dry basis corrected to 3 percent oxygen as determined in accordance with the requirements of § 60.5413.

(C) You must operate at a minimum temperature of 760°C for a control device that can demonstrate a uniform combustion zone temperature during the performance test conducted under § 60.5413.

(D) If a boiler or process heater is used as the control device, then you must introduce the vent stream into the flame zone of the boiler or process heater.

* * * * *

■ 9. Section 60.5413 is amended by revising paragraph (e)(3) to read as follows:

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

* * * * *

(e) * * *

(3) Devices must be operated with no visible emissions, except for periods not to exceed a total of 1 minute during any 15-minute period. A visible emissions test conducted according to section 11 of EPA Method 22, 40 CFR part 60, appendix A, must be performed at least once every calendar month, separated by at least 15 days between each test. The observation period shall be 15 minutes.

* * * * *

■ 10. Section 60.5415 is amended by revising paragraph (b)(2)(vii)(B) to read as follows:

§ 60.5415 How do I demonstrate continuous compliance with the standards for my gas well affected facility, my centrifugal compressor affected facility, my stationary reciprocating compressor affected facility, my pneumatic controller affected facility, my storage vessel affected facility, and my affected facilities at onshore natural gas processing plants?

* * * * *

(b) * * *

(2) * * *

(vii) * * *

(B) Devices must be operated with no visible emissions, except for periods not to exceed a total of 1 minute during any 15-minute period. A visible emissions test conducted according to section 11 of Method 22, 40 CFR part 60, appendix A, must be performed at least once every calendar month, separated by at least 15 days between each test. The observation period shall be 15 minutes.

* * * * *

■ 11. Section 60.5416 is amended by revising paragraph (c)(3)(i) to read as follows:

§ 60.5416 What are the initial and continuous cover and closed vent system inspection and monitoring requirements for my storage vessel and centrifugal compressor affected facility?

* * * * *

(c) * * *

(3) * * *

(i) You must properly install, calibrate and maintain a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere. Set the flow indicator to trigger an audible alarm, and initiate notification via remote alarm to the nearest field office, when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere. You must maintain records of each time the alarm is activated according to § 60.5420(c)(8).

* * * * *

■ 12. Section 60.5417 is amended by adding paragraph (h)(4) to read as follows:

§ 60.5417 What are the continuous control device monitoring requirements for my storage vessel or centrifugal compressor affected facility?

* * * * *

(h) * * *

(4) Conduct a periodic performance test no later than 60 months after the initial performance test as specified in § 60.5413(b)(5)(ii) and conduct subsequent periodic performance tests at intervals no longer than 60 months following the previous periodic performance test.

■ 13. Section 60.5420 is amended by:

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

■ b. Adding paragraph (c)(14).

The revision and addition reads as follows:

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

* * * * *

(c) Recordkeeping requirements. You must maintain the records identified as specified in § 60.7(f) and in paragraphs (c)(1) through (14) of this section. All records required by this subpart must be maintained either onsite or at the nearest local field office for at least 5 years.

* * * * *

(14) A log of records as specified in §§ 60.5412(d)(1)(iii) and 60.5413(e)(4) for all inspection, repair and maintenance activities for each control devices failing the visible emissions test.

■ 14. Section 60.5430 is revised by:

■ a. Adding, in alphabetical order, a definition for the term ''capital expenditure;'' and

■ b. Revising the definition for ''group 2 storage vessel.''

The addition and revision read as follows:

§ 60.5430 What definitions apply to this subpart?

* * * * *

Capital expenditure means, in addition to the definition in 40 CFR 60.2, an expenditure for a physical or operational change to an existing facility that:

(1) Exceeds P, the product of the facility's replacement cost, R, and an adjusted annual asset guideline repair allowance, A, as reflected by the following equation: $P = R \times A$, where

(i) The adjusted annual asset guideline repair allowance, A, is the product of the percent of the replacement cost, Y, and the applicable basic annual asset guideline repair allowance, B, divided by 100 as reflected by the following equation:

$A = Y \times (B \div 100)$;

(ii) The percent Y is determined from the following equation: $Y = 1.0 - 0.575 \log X$, where X is 2011 minus the year of construction; and

(iii) The applicable basic annual asset guideline repair allowance, B, is 4.5.

* * * * *

Group 2 storage vessel means a storage vessel, as defined in this section, for which construction, modification or reconstruction has commenced after April 12, 2013, and on or before September 18, 2015.

* * * * *

■ 15. Amend Table 3 to Subpart OOOO by revising entries ''§ 60.15'' and ''§ 60.18'' to read as follows:

TABLE 3 TO SUBPART OOOO OF PART 60—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART OOOO

General provisions citation	Subject of citation	Applies to subpart?	Explanation
*	*	*	* * * *
§ 60.15	Reconstruction	Yes	Except that § 60.15(d) does not apply to pneumatic controllers, centrifugal compressors or storage vessels.
*	*	*	* * * *
§ 60.18	General control device requirements.	Yes	
*	*	*	* * * *

■ 16. Add subpart OOOOa, consisting of sections 60.5360a through 60.5430a, to part 60 to read as follows:

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

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

§ 60.5360a What is the purpose of this subpart?

This subpart establishes emission standards and compliance schedules for the control of methane, volatile organic compounds (VOC) and sulfur dioxide (SO_2) emissions from affected facilities in the crude oil and natural gas source category that commence construction, modification or reconstruction after September 18, 2015. The effective date of the rule is [date 60 days after publication of final rule in the **Federal Register**].

§ 60.5365a Am I subject to this subpart?

You are subject to the applicable provisions of this subpart if you are the owner or operator of one or more of the onshore affected facilities listed in paragraphs (a) through (j) of this section for which you commence construction, modification or reconstruction after September 18, 2015.

(a) Each well affected facility, which is a single well that conducts a well completion operation following hydraulic fracturing or refracturing and has a gas-to-oil ratio of greater than 300 scf of gas per barrel of oil produced. The provisions of this paragraph do not affect the affected facility status of well sites for the purposes of § 60.5397a. The provisions of paragraphs (a)(1) through (4) of this section apply to wells that are hydraulically refractured:

(1) A well that conducts a well completion operation following hydraulic refracturing is not an affected facility, provided that the requirements of § 60.5375a(a)(1) through (4) are met. However, hydraulic refracturing of a well constitutes a modification of the well site for purposes of § 60.5397a, regardless of affected facility status of the well itself.

(2) A well completion operation following hydraulic refracturing not conducted pursuant to § 60.5375a(a)(1) through (4) is a modification to the well.

(3) Refracturing of a well does not affect the modification status of other equipment, process units, storage vessels, compressors, pneumatic pumps, or pneumatic controllers.

(4) A well initially constructed after September 18, 2015, that conducts a well completion operation following hydraulic refracturing is considered an affected facility regardless of this provision.

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

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

(d)(1) Each pneumatic controller affected facility not located at a natural gas processing plant, which is a single continuous bleed natural gas-driven pneumatic controller operating at a natural gas bleed rate greater than 6 scfh.

(2) Each pneumatic controller affected facility located at a natural gas processing plant, which is a single continuous bleed natural gas-driven pneumatic controller.

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

(1) For each new, modified or reconstructed storage vessel receiving liquids pursuant to the standards for well affected facilities in § 60.5375a, including wells subject to § 60.5375a(f), you must determine the potential for VOC emissions within 30 days after startup of production.

(2) A storage vessel affected facility that subsequently has its potential for VOC emissions decrease to less than 6 tpy shall remain an affected facility under this subpart.

(3) For storage vessels not subject to a legally and practically enforceable limit in an operating permit or other requirement established under Federal, state, local or tribal authority, any vapor from the storage vessel that is recovered and routed to a process through a VRU designed and operated as specified in this section is not required to be included in the determination of VOC potential to emit for purposes of determining affected facility status, provided you comply with the requirements in paragraphs (e)(3)(i) through (iv) of this section.

(i) You meet the cover requirements specified in § 60.5411a(b).

(ii) You meet the closed vent system requirements specified in § 60.5411a(c).

(iii) You maintain records that document compliance with paragraphs (e)(3)(i) and (ii) of this section.

(iv) In the event of removal of apparatus that recovers and routes vapor to a process, or operation that is inconsistent with the conditions specified in paragraphs (e)(3)(i) and (ii) of this section, you must determine the storage vessel's potential for VOC emissions according to this section within 30 days of such removal or operation.

(4) For each new, reconstructed, or modified storage vessel with startup, startup of production, or which is returned to service, affected facility status is determined as follows: If a storage vessel is reconnected to the original source of liquids or is used to replace any storage vessel affected facility, it is a storage vessel affected facility subject to the same requirements as before being removed from service, or applicable to the storage vessel affected facility being replaced, immediately upon startup, startup of production, or return to service.

(f) The group of all equipment, except compressors, within a process unit is an affected facility.

(1) Addition or replacement of equipment for the purpose of process improvement that is accomplished without a capital expenditure shall not by itself be considered a modification under this subpart.

(2) Equipment associated with a compressor station, dehydration unit, sweetening unit, underground storage vessel, field gas gathering system, or liquefied natural gas unit is covered by §§ 60.5400a, 60.5401a, 60.5402a, 60.5421a, and 60.5422a of this subpart if it is located at an onshore natural gas processing plant. Equipment not located at the onshore natural gas processing plant site is exempt from the provisions of §§ 60.5400a, 60.5401a, 60.5402a, 60.5421a, and 60.5422a of this subpart.

(3) The equipment within a process unit of an affected facility located at onshore natural gas processing plants and described in paragraph (f) of this section are exempt from this subpart if they are subject to and controlled according to subparts VVa, GGG or GGGa of this part.

(g) Sweetening units located at onshore natural gas processing plants that process natural gas produced from either onshore or offshore wells.

(1) Each sweetening unit that processes natural gas is an affected facility; and

(2) Each sweetening unit that processes natural gas followed by a sulfur recovery unit is an affected facility.

(3) Facilities that have a design capacity less than 2 long tons per day (LT/D) of hydrogen sulfide (H_2S) in the acid gas (expressed as sulfur) are required to comply with recordkeeping and reporting requirements specified in § 60.5423a(c) but are not required to comply with §§ 60.5405a through 60.5407a and §§ 60.5410a(g) and 60.5415a(g) of this subpart.

(4) Sweetening facilities producing acid gas that is completely reinjected into oil-or-gas-bearing geologic strata or that is otherwise not released to the atmosphere are not subject to §§ 60.5405a through 60.5407a, 60.5410a(g), 60.5415a(g), and 60.5423a of this subpart.

(h)(1) For natural gas processing plants, each pneumatic pump affected facility, which is a single natural gas-driven chemical/methanol pump or natural gas-driven diaphragm pump.

(2) For locations other than natural gas processing plants, each pneumatic pump affected facility, which is a single natural gas-driven chemical/methanol pump or natural gas-driven diaphragm pump for which a control device is located on site.

(i) Except as provided in § 60.5365a(i)(1) through (i)(2), the collection of fugitive emissions components at a well site, as defined in § 60.5430a, is an affected facility.

(1) A well site with average combined oil and natural gas production for the wells at the site being less than 15 barrels of oil equivalent (boe) per day averaged over the first 30 days of production, is not an affected facility under this subpart.

(2) A well site that only contains one or more wellheads is not an affected facility under this subpart.

(3) For purposes of § 60.5397a, a ''modification'' to a well site occurs when:

(i) A new well is drilled at an existing well site;

(ii) A well at an existing well site is hydraulically fractured; or

(iii) A well at an existing well site is hydraulically refractured.

(j) The collection of fugitive emissions components at a compressor station, as defined in § 60.5430a, is an affected facility. For purposes of § 60.5397a, a ''modification'' to a compressor station occurs when:

(1) A new compressor is constructed at an existing compressor station; or

(2) A physical change is made to an existing compressor at a compressor station that increases the compression capacity of the compressor station.

(3) Reserved

§ 60.5370a When must I comply with this subpart?

(a) You must be in compliance with the standards of this subpart no later than [date 60 days after publication of final rule in the **Federal Register**] or upon startup, whichever is later.

(b) The provisions for exemption from compliance during periods of startup, shutdown and malfunctions provided for in 40 CFR 60.8(c) do not apply to this subpart.

(c) You are exempt from the obligation to obtain a permit under 40 CFR part 70 or 40 CFR part 71, provided you are not otherwise required by law to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a). Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart.

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

If you are the owner or operator of a well affected facility, you must reduce methane and VOC emissions by complying with paragraphs (a) through (f) of this section.

(a) Except as provided in paragraph (f) of this section, for each well completion operation with hydraulic fracturing you must comply with the requirements in paragraphs (a)(1) through (4) of this section. You must maintain a log as specified in paragraph (b) of this section.

(1) For each stage of the well completion operation, as defined in § 60.5430a, follow the requirements specified in paragraphs (a)(1)(i) and (ii) of this section.

(i) During the initial flowback stage, route the flowback into one or more well completion vessels or storage vessels and commence operation of a separator unless it is technically infeasible for a separator to function. Any gas present in the initial flowback stage is not subject to control under this section.

(ii) During the separation flowback stage, route all recovered liquids from the separator to one or more well completion vessels or storage vessels, re-inject the recovered liquids into the well or another well or route the recovered liquids to a collection system. Route the recovered gas from the separator into a gas flow line or collection system, re-inject the recovered gas into the well or another well, use the recovered gas as an on-site fuel source, or use the recovered gas for another useful purpose that a purchased fuel or raw material would serve. If it is technically infeasible to route the recovered gas as required above, follow the requirements in paragraph (a)(3) of this section. If, at any time during the separation flowback stage, it is not technically feasible for a separator to function, you must comply with (a)(1)(i) of this section.

(2) All salable quality recovered gas must be routed to the gas flow line as soon as practicable. In cases where salable quality gas cannot be directed to the flow line due to technical infeasibility, you must follow the requirements in paragraph (a)(3) of this section.

(3) You must capture and direct recovered gas to a completion combustion device, except in conditions that may result in a fire hazard or explosion, or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost or waterways. Completion combustion devices must be equipped with a reliable continuous ignition source.

(4) You have a general duty to safely maximize resource recovery and minimize releases to the atmosphere during flowback and subsequent recovery.

(b) You must maintain a log for each well completion operation at each well affected facility. The log must be completed on a daily basis for the duration of the well completion operation and must contain the records specified in § 60.5420a(c)(1)(iii).

(c) You must demonstrate initial compliance with the standards that apply to well affected facilities as required by § 60.5410a.

(d) You must demonstrate continuous compliance with the standards that apply to well affected facilities as required by § 60.5415a.

(e) You must perform the required notification, recordkeeping and reporting as required by § 60.5420a.

(f)(1) For each well affected facility specified in paragraphs (f)(1)(i) and (ii) of this section, you must comply with the requirements of paragraphs (f)(2) and (3) of this section.

(i) Each well completion operation with hydraulic fracturing at a wildcat or delineation well.

(ii) Each well completion operation with hydraulic fracturing at a non-wildcat low pressure well or non-delineation low pressure well.

(2) Route the flowback into one or more well completion vessels and commence operation of a separator unless it is technically infeasible for a separator to function. Any gas present in the flowback before the separator can function is not subject to control under this section. You must capture and direct recovered gas to a completion combustion device, except in conditions that may result in a fire hazard or explosion, or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost or waterways. Completion combustion devices must be equipped with a reliable continuous ignition source. You must also comply with paragraphs (a)(4) and (b) through (e) of this section.

(3) You must maintain records specified in § 60.5420a(c)(1)(iii) for wildcat, delineation and low pressure wells.

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

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

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

(2) If you use a control device to reduce emissions, you must equip the wet seal fluid degassing system with a cover that meets the requirements of § 60.5411a(b). The cover must be connected through a closed vent system that meets the requirements of § 60.5411a(a) and the closed vent system must be routed to a control device that meets the conditions specified in § 60.5412a(a), (b) and (c). As an alternative to routing the closed vent system to a control device, you may route the closed vent system to a process.

(b) You must demonstrate initial compliance with the standards that apply to centrifugal compressor affected facilities as required by § 60.5410a(b).

(c) You must demonstrate continuous compliance with the standards that apply to centrifugal compressor affected facilities as required by § 60.5415a(b).

(d) You must perform the required notification, recordkeeping, and reporting as required by § 60.5420a.

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

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

(a) You must replace the reciprocating compressor rod packing according to either paragraph (a)(1) or (2) of this section or you must comply with paragraph (a)(3) of this section.

(1) Before the compressor has operated for 26,000 hours. The number of hours of operation must be continuously monitored beginning upon initial startup of your reciprocating compressor affected facility, or the date of the most recent reciprocating compressor rod packing replacement, whichever is later.

(2) Prior to 36 months from the date of the most recent rod packing replacement, or 36 months from the date of startup for a new reciprocating compressor for which the rod packing has not yet been replaced.

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

(b) You must demonstrate initial compliance with standards that apply to reciprocating compressor affected facilities as required by § 60.5410a.

(c) You must demonstrate continuous compliance with standards that apply to reciprocating compressor affected facilities as required by § 60.5415a.

(d) You must perform the required notification, recordkeeping, and reporting as required by § 60.5420a.

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

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

(a) The requirements of paragraph (b)(1) or (c)(1) of this section are not required if you determine that the use of a pneumatic controller affected facility with a bleed rate greater than the applicable standard is required based on functional needs, including but not limited to response time, safety and positive actuation. However, you must tag such pneumatic controller with the month and year of installation, reconstruction or modification, and identification information that allows traceability to the records for that pneumatic controller, as required in § 60.5420a(c)(4)(ii).

(b)(1) Each pneumatic controller affected facility at a natural gas processing plant must have a bleed rate of zero.

(2) Each pneumatic controller affected facility at a natural gas processing plant must be tagged with the month and year of installation, reconstruction or modification, and identification information that allows traceability to the records for that pneumatic controller as required in § 60.5420a(c)(4)(iv).

(c)(1) Each pneumatic controller affected facility at a location other than at a natural gas processing plant must have a bleed rate less than or equal to 6 standard cubic feet per hour.

(2) Each pneumatic controller affected facility constructed, modified or reconstructed on or after October 15, 2013, at a location other than at a natural gas processing plant must be tagged with the month and year of installation, reconstruction or modification, and identification information that allows traceability to the records for that controller as required in § 60.5420a(c)(4)(iii).

(d) You must demonstrate initial compliance with standards that apply to pneumatic controller affected facilities as required by § 60.5410a.

(e) You must demonstrate continuous compliance with standards that apply to pneumatic controller affected facilities as required by § 60.5415a.

(f) You must perform the required notification, recordkeeping, and reporting as required by § 60.5420a, except that you are not required to submit the notifications specified in § 60.5420a(a).

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

For each pneumatic pump affected facility you must comply with the methane and VOC standards, based on natural gas as a surrogate for methane and VOC, in either paragraph (a)(1) or (b)(1) of this section, as applicable.

(a)(1) Each pneumatic pump affected facility at a natural gas processing plant must have a natural gas emission rate of zero.

(2) Each pneumatic pump affected facility at a natural gas processing plant must be tagged with the month and year of installation, reconstruction or modification, and identification information that allows traceability to the records for that pneumatic pump as required in § 60.5420a(c)(16)(i).

(b)(1) Each pneumatic pump affected facility at a location other than a natural gas processing plant must reduce natural gas emissions by 95.0 percent, except as provided in paragraph (b)(2) of this section.

(2) You are not required to install a control device solely for the purposes of complying with the 95.0 percent reduction of paragraph (b)(1) of this section. If you do not have a control device installed on-site by the compliance date, then you must comply instead with the provisions of paragraphs (b)(2)(i) and (ii) of this section.

(i) Submit a certification in accordance with § 60.5420(b)(8)(i).

(ii) If you subsequently install a control device, you are no longer required to submit the certification in § 60.5420(b)(8)(i) and must be in compliance with the requirements of paragraph (b)(1) of this section within 30 days of installation of the control device. Compliance with this requirement should be reported in the next annual report in accordance with § 60.5420(b)(8)(iii).

(3) Each pneumatic pump affected facility at a location other than a natural gas processing plant must be tagged with the month and year of installation, reconstruction or modification, and identification information that allows traceability to the records for that pump as required in § 60.5420a(c)(16)(i).

(4) If you use a control device to reduce emissions, you must connect the pneumatic pump affected facility through a closed vent system that meets the requirements of § 60.5411a(a) and route emissions to a control device that meets the conditions specified in § 60.5412a(a), (b) and (c) and performance tested in accordance with § 60.5413a. As an alternative to routing the closed vent system to a control device, you may route the closed vent system to a process.

(c) You must demonstrate initial compliance with standards that apply to pneumatic pump affected facilities as required by § 60.5410a.

(d) You must demonstrate continuous compliance with standards that apply to pneumatic pump affected facilities as required by § 60.5415a.

(e) You must perform the required notification, recordkeeping, and reporting as required by § 60.5420a, except that you are not required to submit the notifications specified in § 60.5420a(a).

§ 60.5395a What VOC standards apply to storage vessel affected facilities?

Except as provided in paragraph (e) of this section, you must comply with the VOC standards in this section for each storage vessel affected facility.

(a) You must comply with either the requirements of paragraphs (a)(1) and (a)(2) or the requirements of paragraph (a)(3) of this section. If you choose to meet the requirements in paragraph (a)(3) of this section, you are not required to comply with the requirements of paragraph (a)(2) of this section except as provided in paragraphs (a)(3)(i) and (ii) of this section.

(1) Determine potential for VOC emissions in accordance with § 60.5365a(e).

(2) Reduce VOC emissions by 95.0 percent within 60 days after startup. For storage vessel affected facilities receiving liquids pursuant to the standards for well affected facilities in § 60.5375a, you must achieve the required emissions reductions within 60 days after startup of production as defined in § 60.5430a.

(3) Maintain the uncontrolled actual VOC emissions from the storage vessel affected facility at less than 4 tpy without considering control. Prior to using the uncontrolled actual VOC emission rate for compliance purposes, you must demonstrate that the uncontrolled actual VOC emissions have remained less than 4 tpy as determined monthly for 12 consecutive months. After such demonstration, you must determine the uncontrolled actual VOC emission rate each month. The uncontrolled actual VOC emissions must be calculated using a generally accepted model or calculation methodology, and the calculations must be based on the average throughput for the month. You must comply with paragraph (a)(2) of this section if your storage vessel affected facility meets the conditions specified in paragraphs (a)(3)(i) or (ii) of this section.

(i) If a well feeding the storage vessel affected facility undergoes fracturing or refracturing, you must comply with paragraph (a)(2) of this section as soon as liquids from the well following fracturing or refracturing are routed to the storage vessel affected facility.

(ii) If the monthly emissions determination required in this section indicates that VOC emissions from your storage vessel affected facility increase to 4 tpy or greater and the increase is not associated with fracturing or refracturing of a well feeding the storage vessel affected facility, you must comply with paragraph (a)(2) of this section within 30 days of the monthly determination.

(b) *Control requirements.* (1) Except as required in paragraph (b)(2) of this section, if you use a control device to reduce VOC emissions from your storage vessel affected facility, you must equip the storage vessel with a cover that meets the requirements of § 60.5411a(b) and is connected through a closed vent system that meets the requirements of § 60.5411a(c), and you must route emissions to a control device that meets the conditions specified in § 60.5412a(c) and (d). As an alternative to routing the closed vent system to a control device, you may route the closed vent system to a process that reduces VOC emissions by at least 95.0 percent.

(2) If you use a floating roof to reduce emissions, you must meet the requirements of § 60.112b(a)(1) or (2) and the relevant monitoring, inspection, recordkeeping, and reporting requirements in 40 CFR part 60, subpart Kb.

(c) *Requirements for storage vessel affected facilities that are removed from service or returned to service.* If you remove a storage vessel affected facility from service, you must comply with paragraphs (c)(1) through (3) of this section. A storage vessel is not an affected facility under this subpart for the period that it is removed from service.

(1) For a storage vessel affected facility to be removed from service, you must comply with the requirements of paragraph (c)(1)(i) and (ii) of this section.

(i) You must completely empty and degas the storage vessel, such that the storage vessel no longer contains crude oil, condensate, produced water or intermediate hydrocarbon liquids. A storage vessel where liquid is left on walls, as bottom clingage or in pools due to floor irregularity is considered to be completely empty.

(ii) You must submit a notification as required in § 60.5420a(b)(6)(v) in your next annual report, identifying each storage vessel affected facility removed from service during the reporting period and the date of its removal from service.

(2) If a storage vessel identified in paragraph (c)(1)(ii) of this section is returned to service, you must determine its affected facility status as provided in § 60.5365a(e).

(3) For each storage vessel affected facility returned to service during the reporting period, you must submit a notification in your next annual report as required in § 60.5420a(b)(6)(vi), identifying each storage vessel affected facility and the date of its return to service.

(d) *Compliance, notification, recordkeeping, and reporting.* You must comply with paragraphs (d)(1) through (3) of this section.

(1) You must demonstrate initial compliance with standards as required by § 60.5410a(h) and (i).

(2) You must demonstrate continuous compliance with standards as required by § 60.5415a(e)(3).

(3) You must perform the required notification, recordkeeping and reporting as required by § 60.5420a.

(e) Exemptions. This subpart does not apply to storage vessels subject to and controlled in accordance with the requirements for storage vessels in 40 CFR part 60, subpart Kb, 40 CFR part 63, subparts G, CC, HH, or WW.

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

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

(a) You must monitor all fugitive emission components, as defined in 60.5430a, in accordance with paragraphs (b) through (i) of this section. You must repair all sources of fugitive emissions in accordance with paragraph (j) of this section. You must keep records in accordance with paragraph (k) and report in accordance with paragraph (l) of this section. For purposes of this section, fugitive emissions are defined as: Any visible emission from a fugitive emissions component observed using optical gas imaging.

(b) You must develop a corporate-wide fugitive emissions monitoring plan that covers the collection of fugitive emissions components at well sites and compressor stations in accordance with paragraph (c) of this section, and you must develop a site-specific fugitive emissions monitoring plan specific to each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a compressor station in accordance with paragraph (d) of this section. Alternatively, you may develop a site-specific plan for each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a compressor station that covers the elements of both the corporate-wide and site-specific plans.

(c) Your corporate-wide monitoring plan must include the elements specified in paragraphs (c)(1) through (8) of this section, as a minimum.

(1) Frequency for conducting surveys. Surveys must be conducted at least as

frequently as required by paragraphs (f) through (i) of this section.

(2) Technique for determining fugitive emissions.

(3) Manufacturer and model number of fugitive emissions detection equipment to be used.

(4) Procedures and timeframes for identifying and repairing fugitive emissions components from which fugitive emissions are detected, including timeframes for fugitive emission components that are unsafe to repair. Your repair schedule must meet the requirements of paragraph (j) of this section at a minimum.

(5) Procedures and timeframes for verifying fugitive emission component repairs.

(6) Records that will be kept and the length of time records will be kept.

(7) Your plan must also include the elements specified in paragraphs (c)(7)(i) through (vii) of this section.

(i) Verification that your optical gas imaging equipment meets the specifications of paragraphs (c)(7)(i)(A) and (B) of this section. This verification is an initial verification and may either be performed by the facility, by the manufacturer, or by a third-party. For the purposes of complying with the fugitives emissions monitoring program with optical gas imaging, a fugitive emission is defined as any visible emissions observed using optical gas imaging.

(A) Your optical gas imaging equipment must be capable of imaging gases in the spectral range for the compound of highest concentration in the potential fugitive emissions.

(B) Your optical gas imaging equipment must be capable of imaging a gas that is half methane, half propane at a concentration of ≤10,000 ppm at a flow rate of ≥60 g/hr from a quarter inch diameter orifice.

(ii) Procedure for a daily verification check.

(iii) Procedure for determining the operator's maximum viewing distance from the equipment and how the operator will ensure that this distance is maintained.

(iv) Procedure for determining maximum wind speed during which monitoring can be performed and how the operator will ensure monitoring occurs only at wind speeds below this threshold.

(v) Procedures for conducting surveys, including the items specified in paragraphs (c)(7)(v)(A) through (C) of this section.

(A) How the operator will ensure an adequate thermal background is present in order to view potential fugitive emissions.

(B) How the operator will deal with adverse monitoring conditions, such as wind.

(C) How the operator will deal with interferences (*e.g.,* steam).

(vi) Training and experience needed prior to performing surveys.

(vii) Procedures for calibration and maintenance. Procedures must comply with those recommended by the manufacturer.

(d) Your site-specific monitoring plan must include the elements specified in paragraphs (d)(1) through (3) of this section, as a minimum.

(1) Deviations from your master plan.

(2) Sitemap.

(3) Your plan must also include your defined walking path. The walking path must ensure that all fugitive emissions components are within sight of the path and must account for interferences.

(e) Each monitoring survey shall observe each fugitive emissions component for fugitive emissions.

(f)(1) You must conduct an initial monitoring survey within 30 days of the first well completion for each collection of fugitive emissions components at a new well site or upon the date the well site begins the production phase for other wells. For a modified collection of fugitive emissions components at a well site, the initial monitoring survey must be conducted within 30 days of the well site modification.

(2) You must conduct an initial monitoring survey within 30 days of the startup of a new compressor station for each new collection of fugitive emissions components at the new compressor station. For modified compressor stations, the initial monitoring survey of the collection of fugitive emissions components at a modified compressor station must be conducted within 30 days of the modification.

(g) A monitoring survey of each collection of fugitive emissions components at a well site and collection of fugitive emissions components at a compressor station shall be conducted at least semiannually after the initial survey. Consecutive semiannual monitoring surveys shall be conducted at least 4 months apart.

(h) The monitoring frequency specified in paragraph (g) of this section shall be increased to quarterly in the event that two consecutive semiannual monitoring surveys detect fugitive emissions at greater than 3.0 percent of the fugitive emissions components at a well site or at greater than 3.0 percent of the fugitive emissions components at a compressor station.

(i) The monitoring frequency specified in paragraph (g) of this section may be decreased to annual in the event that two consecutive semiannual surveys detect fugitive emissions at less than 1.0 percent of the fugitive emissions components at a well site, or at less than 1.0 percent of the fugitive emissions components at a compressor station. The monitoring frequency shall return to semiannual if a survey detects fugitive emissions between 1.0 percent and 3.0 percent of the fugitive emissions components at the well site, or between 1.0 percent and 3.0 percent of the fugitive emissions components at the compressor station.

(j) For fugitive emissions components also subject to the repair provisions of §§ 60.5416a(b)(9) through (12) and (c)(4) through (7), those provisions apply instead to those closed vent system and covers, and the repair provisions of paragraphs (j)(1) and (2) of this section do not apply to those closed vent systems and covers.

(1) Each identified source of fugitive emissions shall be repaired or replaced as soon as practicable, but no later than 15 calendar days after detection of the fugitive emissions. If the repair or replacement is technically infeasible or unsafe to repair during operation of the unit, the repair or replacement must be completed during the next scheduled shutdown or within 6 months, whichever is earlier.

(2) Each repaired or replaced fugitive emissions component must be resurveyed as soon as practicable, but no later than 15 days of finding such fugitive emissions, to ensure that there is no leak.

(i) For repairs that cannot be made during the monitoring survey when the fugitive emissions are initially found, the operator may resurvey the repaired fugitive emissions components using either Method 21 or optical gas imaging within 15 days of finding such fugitive emissions.

(ii) Operators that use Method 21 to resurvey the repaired fugitive emissions components, are subject to the resurvey provisions specified in paragraphs (j)(2)(ii)(A) and (B).

(A) A fugitive emissions component is repaired when the Method 21 instrument indicates a concentration of less than 500 ppm above background.

(B) Operators must use the Method 21 monitoring requirements specified in paragraph § 60.5401a(g).

(iii) Operators that use optical gas imaging to resurvey the repaired fugitive emissions components, are subject to the resurvey provisions specified in paragraphs (j)(2)(iii)(A) and (B).

(A) A fugitive emissions component is repaired when the optical gas imaging instrument shows no indication of visible emissions.

(B) Operators must use the optical gas imaging monitoring requirements specified in paragraph (a).

(k) Records for each monitoring survey shall be maintained as specified § 60.5420a(c)(15) and must contain, at a minimum, the information specified in paragraphs (k)(1) through (6) of this section.

(1) Date of the survey.

(2) Beginning and end time of the survey.

(3) Name of operator(s) performing survey. You must note the training and experience of the operator.

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

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

(6) Documentation of each source of fugitive emissions (*e.g.,* fugitive emissions components), including the information specified in paragraphs (k)(6)(i) through (ii) of this section.

(i) Location.

(ii) One or more digital photographs of each required monitoring survey being performed. The digital photograph must include the date the photograph was taken and the latitude and longitude of the well site or compressor station imbedded within or stored with the digital file. As an alternative to imbedded latitude and longitude within the digital photograph, the digital photograph may consist of a photograph of the monitoring survey being performed with a photograph of a separately operating GIS device within the same digital picture, provided the latitude and longitude output of the GIS unit can be clearly read in the digital photograph.

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

(iv) The instrument used to resurvey a repaired fugitive emissions component that could not be repaired during the initial fugitive emissions finding.

(l) Annual reports shall be submitted for each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a compressor station that include the information specified in § 60.5420a(b)(7). Multiple collection of fugitive emissions components at a well site or collection of fugitive emissions at a compressor station may be included in a single annual report.

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

This section applies to the group of all equipment, except compressors, within a process unit.

(a) You must comply with the requirements of §§ 60.482–1a(a), (b), and (d), 60.482–2a, and 60.482–4a through 60.482–11a, except as provided in § 60.5401a.

(b) You may elect to comply with the requirements of §§ 60.483–1a and 60.483–2a, as an alternative.

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

(d) You must comply with the provisions of § 60.485a except as provided in paragraph (f) of this section.

(e) You must comply with the provisions of §§ 60.486a and 60.487a of this part except as provided in §§ 60.5401a, 60.5421a, and 60.5422a.

(f) You must use the following provision instead of § 60.485a(d)(1): Each piece of equipment is presumed to be in VOC service or in wet gas service unless an owner or operator demonstrates that the piece of equipment is not in VOC service or in wet gas service. For a piece of equipment to be considered not in VOC service, it must be determined that the VOC content can be reasonably expected never to exceed 10.0 percent by weight. For a piece of equipment to be considered in wet gas service, it must be determined that it contains or contacts the field gas before the extraction step in the process. For purposes of determining the percent VOC content of the process fluid that is contained in or contacts a piece of equipment, procedures that conform to the methods described in ASTM E169–93, E168–92, or E260–96 (incorporated by reference as specified in § 60.17) must be used.

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

(a) You may comply with the following exceptions to the provisions of § 60.5400a(a) and (b).

(b)(1) Each pressure relief device in gas/vapor service may be monitored quarterly and within 5 days after each pressure release to detect leaks by the methods specified in § 60.485a(b) except as provided in § 60.5400a(c) and in paragraph (b)(4) of this section, and § 60.482–4a(a) through (c) of subpart VVa of this part.

(2) If an instrument reading of 500 ppm or greater is measured, a leak is detected.

(3)(i) When a leak is detected, it must be repaired as soon as practicable, but no later than 15 calendar days after it is detected, except as provided in § 60.482–9a.

(ii) A first attempt at repair must be made no later than 5 calendar days after each leak is detected.

(4)(i) Any pressure relief device that is located in a nonfractionating plant that is monitored only by non-plant personnel may be monitored after a pressure release the next time the monitoring personnel are on-site, instead of within 5 days as specified in paragraph (b)(1) of this section and § 60.482–4a(b)(1) of subpart VVa of this part.

(ii) No pressure relief device described in paragraph (b)(4)(i) of this section may be allowed to operate for more than 30 days after a pressure release without monitoring.

(c) Sampling connection systems are exempt from the requirements of § 60.482–5a.

(d) Pumps in light liquid service, valves in gas/vapor and light liquid service, pressure relief devices in gas/vapor service, and connectors in gas/vapor service and in light liquid service that are located at a nonfractionating plant that does not have the design capacity to process 283,200 standard cubic meters per day (scmd) (10 million standard cubic feet per day) or more of field gas are exempt from the routine monitoring requirements of §§ 60.482–2a(a)(1), 60.482–7a(a), 60.482–11a(a), and paragraph (b)(1) of this section.

(e) Pumps in light liquid service, valves in gas/vapor and light liquid service, pressure relief devices in gas/vapor service, and connectors in gas/vapor service and in light liquid service within a process unit that is located in the Alaskan North Slope are exempt from the routine monitoring requirements of §§ 60.482–2a(a)(1), 60.482–7a(a), 60.482–11a(a), and paragraph (b)(1) of this section.

(f) An owner or operator may use the following provisions instead of § 60.485a(e):

(1) Equipment is in heavy liquid service if the weight percent evaporated is 10 percent or less at 150 °C (302 °F) as determined by ASTM Method D86–96 (incorporated by reference as specified in § 60.17).

(2) Equipment is in light liquid service if the weight percent evaporated is greater than 10 percent at 150 °C (302

°F) as determined by ASTM Method D86–96 (incorporated by reference as specified in § 60.17).

(g) An owner or operator may use the following provisions instead of § 60.485a(b)(2): A calibration drift assessment shall be performed, at a minimum, at the end of each monitoring day. Check the instrument using the same calibration gas(es) that were used to calibrate the instrument before use. Follow the procedures specified in Method 21 of appendix A–7 of this part, Section 10.1, except do not adjust the meter readout to correspond to the calibration gas value. Record the instrument reading for each scale used as specified in § 60.486a(e)(8). Divide these readings by the initial calibration values for each scale and multiply by 100 to express the calibration drift as a percentage. If any calibration drift assessment shows a negative drift of more than 10 percent from the initial calibration value, then all equipment monitored since the last calibration with instrument readings below the appropriate leak definition and above the leak definition multiplied by (100 minus the percent of negative drift/divided by 100) must be re-monitored. If any calibration drift assessment shows a positive drift of more than 10 percent from the initial calibration value, then, at the owner/operator's discretion, all equipment since the last calibration with instrument readings above the appropriate leak definition and below the leak definition multiplied by (100 plus the percent of positive drift/divided by 100) may be re-monitored.

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

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

(b) Any notice under paragraph (a) of this section must be published only after notice and an opportunity for a public hearing.

(c) The Administrator will consider applications under this section from either owners or operators of affected facilities, or manufacturers of control equipment.

(d) The Administrator will treat applications under this section according to the following criteria, except in cases where the Administrator concludes that other criteria are appropriate:

(1) The applicant must collect, verify and submit test data, covering a period of at least 12 months, necessary to support the finding in paragraph (a) of this section.

(2) If the applicant is an owner or operator of an affected facility, the applicant must commit in writing to operate and maintain the alternative means so as to achieve a reduction in methane and VOC emissions at least equivalent to the reduction in methane and VOC emissions achieved under the design, equipment, work practice or operational standard.

§ 60.5405a What standards apply to sweetening units at onshore natural gas processing plants?

(a) During the initial performance test required by § 60.8(b), you must achieve at a minimum, an SO_2 emission reduction efficiency (Z_i) to be determined from Table 1 of this subpart based on the sulfur feed rate (X) and the sulfur content of the acid gas (Y) of the affected facility.

(b) After demonstrating compliance with the provisions of paragraph (a) of this section, you must achieve at a minimum, an SO_2 emission reduction efficiency (Z_c) to be determined from Table 2 of this subpart based on the sulfur feed rate (X) and the sulfur content of the acid gas (Y) of the affected facility.

§ 60.5406a What test methods and procedures must I use for my sweetening units affected facilities at onshore natural gas processing plants?

(a) In conducting the performance tests required in § 60.8, you must use the test methods in appendix A of this part or other methods and procedures as specified in this section, except as provided in paragraph § 60.8(b).

(b) During a performance test required by § 60.8, you must determine the minimum required reduction efficiencies (Z) of SO_2 emissions as required in § 60.5405a(a) and (b) as follows:

(1) The average sulfur feed rate (X) must be computed as follows:

$$X = KQ_aY$$

Where:

X = average sulfur feed rate, Mg/D (LT/D).

Q_a = average volumetric flow rate of acid gas from sweetening unit, dscm/day (dscf/day).

Y = average H2S concentration in acid gas feed from sweetening unit, percent by volume, expressed as a decimal.

K = (32 kg S/kg-mole)/((24.04 dscm/kg-mole) (1000 kg S/Mg)).

= 1.331×10^{-3} Mg/dscm, for metric units.

= (32 lb S/lb-mole)/((385.36 dscf/lb-mole) (2240 lb S/long ton)).

= 3.707×10^{-5} long ton/dscf, for English units.

(2) You must use the continuous readings from the process flowmeter to determine the average volumetric flow rate (Q_a) in dscm/day (dscf/day) of the acid gas from the sweetening unit for each run.

(3) You must use the Tutwiler procedure in § 60.5408a or a chromatographic procedure following ASTM E260–96 (incorporated by reference as specified in § 60.17) to determine the H_2S concentration in the acid gas feed from the sweetening unit (Y). At least one sample per hour (at equally spaced intervals) must be taken during each 4-hour run. The arithmetic mean of all samples must be the average H_2S concentration (Y) on a dry basis for the run. By multiplying the result from the Tutwiler procedure by 1.62×10^{-3}, the units gr/100 scf are converted to volume percent.

(4) Using the information from paragraphs (b)(1) and (b)(3) of this section, Tables 1 and 2 of this subpart must be used to determine the required initial (Z_i) and continuous (Z_c) reduction efficiencies of SO_2 emissions.

(c) You must determine compliance with the SO_2 standards in § 60.5405a(a) or (b) as follows:

(1) You must compute the emission reduction efficiency (R) achieved by the sulfur recovery technology for each run using the following equation:

$$R = (100S)/(S + E)$$

(2) You must use the level indicators or manual soundings to measure the liquid sulfur accumulation rate in the product storage vessels. You must use readings taken at the beginning and end of each run, the tank geometry, sulfur density at the storage temperature, and sample duration to determine the sulfur production rate (S) in kg/hr (lb/hr) for each run.

(3) You must compute the emission rate of sulfur for each run as follows:

$$E = C_eQ_{sd}/K\ 1$$

Where:

E = emission rate of sulfur per run, kg/hr.

Ce = concentration of sulfur equivalent (SO^{2+} reduced sulfur), g/dscm (lb/dscf).

Q_{sd} = volumetric flow rate of effluent gas, dscm/hr (dscf/hr).

K_1 = conversion factor, 1000 g/kg (7000 gr/lb).

(4) The concentration (C_e) of sulfur equivalent must be the sum of the SO_2

and TRS concentrations, after being converted to sulfur equivalents. For each run and each of the test methods specified in this paragraph (c) of this section, you must use a sampling time of at least 4 hours. You must use Method 1 of appendix A–1 of this part to select the sampling site. The sampling point in the duct must be at the centroid of the cross-section if the area is less than 5 m^2 (54 ft^2) or at a point no closer to the walls than 1 m (39 in) if the cross-sectional area is 5 m^2 or more, and the centroid is more than 1 m (39 in) from the wall.

(i) You must use Method 6 of appendix A–4 of this part to determine the SO_2 concentration. You must take eight samples of 20 minutes each at 30-minute intervals. The arithmetic average must be the concentration for the run. The concentration must be multiplied by 0.5×10^{-3} to convert the results to sulfur equivalent. In place of Method 6 of Appendix A of this part, you may use ASME/ANSI PTC 19.10–1981, Part 10 (manual portion only) (incorporated by reference as specified in § 60.17)

(ii) You must use Method 15 of appendix A–5 of this part to determine the TRS concentration from reduction-type devices or where the oxygen content of the effluent gas is less than 1.0 percent by volume. The sampling rate must be at least 3 liters/min (0.1 ft^3/min) to insure minimum residence time in the sample line. You must take sixteen samples at 15-minute intervals. The arithmetic average of all the samples must be the concentration for the run. The concentration in ppm reduced sulfur as sulfur must be multiplied by 1.333×10^{-3} to convert the results to sulfur equivalent.

(iii) You must use Method 16A of appendix A–6 of this part or Method 15 of appendix A–5 of this part or ASME/ANSI PTC 19.10–1981, Part 10 (manual portion only) (incorporated by reference as specified in § 60.17) to determine the reduced sulfur concentration from oxidation-type devices or where the oxygen content of the effluent gas is greater than 1.0 percent by volume. You must take eight samples of 20 minutes each at 30-minute intervals. The arithmetic average must be the concentration for the run. The concentration in ppm reduced sulfur as sulfur must be multiplied by 1.333×10^{-3} to convert the results to sulfur equivalent.

(iv) You must use Method 2 of appendix A–1 of this part to determine the volumetric flow rate of the effluent gas. A velocity traverse must be conducted at the beginning and end of each run. The arithmetic average of the two measurements must be used to calculate the volumetric flow rate (Q_{sd}) for the run. For the determination of the effluent gas molecular weight, a single integrated sample over the 4-hour period may be taken and analyzed or grab samples at 1-hour intervals may be taken, analyzed, and averaged. For the moisture content, you must take two samples of at least 0.10 dscm (3.5 dscf) and 10 minutes at the beginning of the 4-hour run and near the end of the time period. The arithmetic average of the two runs must be the moisture content for the run.

§ 60.5407a What are the requirements for monitoring of emissions and operations from my sweetening unit affected facilities at onshore natural gas processing plants?

(a) If your sweetening unit affected facility is located at an onshore natural gas processing plant and is subject to the provisions of § 60.5405a(a) or (b) you must install, calibrate, maintain, and operate monitoring devices or perform measurements to determine the following operations information on a daily basis:

(1) *The accumulation of sulfur product over each 24-hour period.* The monitoring method may incorporate the use of an instrument to measure and record the liquid sulfur production rate, or may be a procedure for measuring and recording the sulfur liquid levels in the storage vessels with a level indicator or by manual soundings, with subsequent calculation of the sulfur production rate based on the tank geometry, stored sulfur density, and elapsed time between readings. The method must be designed to be accurate within ±2 percent of the 24-hour sulfur accumulation.

(2) *The H_2S concentration in the acid gas from the sweetening unit for each 24-hour period.* At least one sample per 24-hour period must be collected and analyzed using the equation specified in § 60.5406a(b)(1). The Administrator may require you to demonstrate that the H_2S concentration obtained from one or more samples over a 24-hour period is within ±20 percent of the average of 12 samples collected at equally spaced intervals during the 24-hour period. In instances where the H_2S concentration of a single sample is not within ±20 percent of the average of the 12 equally spaced samples, the Administrator may require a more frequent sampling schedule.

(3) *The average acid gas flow rate from the sweetening unit.* You must install and operate a monitoring device to continuously measure the flow rate of acid gas. The monitoring device reading must be recorded at least once per hour during each 24-hour period. The average acid gas flow rate must be computed from the individual readings.

(4) *The sulfur feed rate (X).* For each 24-hour period, you must compute X using the equation specified in § 60.5406a(b)(1).

(5) *The required sulfur dioxide emission reduction efficiency for the 24-hour period.*You must use the sulfur feed rate and the H_2S concentration in the acid gas for the 24-hour period, as applicable, to determine the required reduction efficiency in accordance with the provisions of § 60.5405a(b).

(b) Where compliance is achieved through the use of an oxidation control system or a reduction control system followed by a continually operated incineration device, you must install, calibrate, maintain, and operate monitoring devices and continuous emission monitors as follows:

(1) A continuous monitoring system to measure the total sulfur emission rate (E) of SO_2 in the gases discharged to the atmosphere. The SO_2 emission rate must be expressed in terms of equivalent sulfur mass flow rates (kg/hr (lb/hr)). The span of this monitoring system must be set so that the equivalent emission limit of § 60.5405a(b) will be between 30 percent and 70 percent of the measurement range of the instrument system.

(2) Except as provided in paragraph (b)(3) of this section: A monitoring device to measure the temperature of the gas leaving the combustion zone of the incinerator, if compliance with § 60.5405a(a) is achieved through the use of an oxidation control system or a reduction control system followed by a continually operated incineration device. The monitoring device must be certified by the manufacturer to be accurate to within ±1 percent of the temperature being measured.

(3) When performance tests are conducted under the provision of § 60.8 to demonstrate compliance with the standards under § 60.5405a, the temperature of the gas leaving the incinerator combustion zone must be determined using the monitoring device. If the volumetric ratio of sulfur dioxide to sulfur dioxide plus total reduced sulfur (expressed as SO_2) in the gas leaving the incinerator is equal to or less than 0.98, then temperature monitoring may be used to demonstrate that sulfur dioxide emission monitoring is sufficient to determine total sulfur emissions. At all times during the operation of the facility, you must maintain the average temperature of the gas leaving the combustion zone of the incinerator at or above the appropriate level determined during the most recent performance test to ensure the sulfur

compound oxidation criteria are met. Operation at lower average temperatures may be considered by the Administrator to be unacceptable operation and maintenance of the affected facility. You may request that the minimum incinerator temperature be reestablished by conducting new performance tests under § 60.8.

(4) Upon promulgation of a performance specification of continuous monitoring systems for total reduced sulfur compounds at sulfur recovery plants, you may, as an alternative to paragraph (b)(2) of this section, install, calibrate, maintain, and operate a continuous emission monitoring system for total reduced sulfur compounds as required in paragraph (d) of this section in addition to a sulfur dioxide emission monitoring system. The sum of the equivalent sulfur mass emission rates from the two monitoring systems must be used to compute the total sulfur emission rate (E).

(c) Where compliance is achieved through the use of a reduction control system not followed by a continually operated incineration device, you must install, calibrate, maintain, and operate a continuous monitoring system to measure the emission rate of reduced sulfur compounds as SO_2 equivalent in the gases discharged to the atmosphere. The SO_2 equivalent compound emission rate must be expressed in terms of equivalent sulfur mass flow rates (kg/hr (lb/hr)). The span of this monitoring system must be set so that the equivalent emission limit of § 60.5405a(b) will be between 30 and 70 percent of the measurement range of the system. This requirement becomes effective upon promulgation of a performance specification for continuous monitoring systems for total reduced sulfur compounds at sulfur recovery plants.

(d) For those sources required to comply with paragraph (b) or (c) of this section, you must calculate the average sulfur emission reduction efficiency achieved (R) for each 24-hour clock interval. The 24-hour interval may begin and end at any selected clock time, but must be consistent. You must compute the 24-hour average reduction efficiency (R) based on the 24-hour average sulfur production rate (S) and sulfur emission rate (E), using the equation in § 60.5406a(c)(1).

(1) You must use data obtained from the sulfur production rate monitoring device specified in paragraph (a) of this section to determine S.

(2) You must use data obtained from the sulfur emission rate monitoring systems specified in paragraphs (b) or (c) of this section to calculate a 24-hour average for the sulfur emission rate (E). The monitoring system must provide at least one data point in each successive 15-minute interval. You must use at least two data points to calculate each 1-hour average. You must use a minimum of 18 1-hour averages to compute each 24-hour average.

(e) In lieu of complying with paragraphs (b) or (c) of this section, those sources with a design capacity of less than 152 Mg/D (150 LT/D) of H_2S expressed as sulfur may calculate the sulfur emission reduction efficiency achieved for each 24-hour period by:

$$R = \frac{K_2 S}{X}$$

Where:

R = The sulfur dioxide removal efficiency achieved during the 24-hour period, percent.

K_2 = Conversion factor, 0.02400 Mg/D per kg/hr (0.01071 LT/D per lb/hr).

S = The sulfur production rate during the 24-hour period, kg/hr (lb/hr).

X = The sulfur feed rate in the acid gas, Mg/D (LT/D).

(f) The monitoring devices required in paragraphs (b)(1), (b)(3) and (c) of this section must be calibrated at least annually according to the manufacturer's specifications, as required by § 60.13(b).

(g) The continuous emission monitoring systems required in paragraphs (b)(1), (b)(3), and (c) of this section must be subject to the emission monitoring requirements of § 60.13 of the General Provisions. For conducting the continuous emission monitoring system performance evaluation required by § 60.13(c), Performance Specification 2 of appendix B of this part must apply, and Method 6 of appendix A–4 of this part must be used for systems required by paragraph (b) of this section. In place of Method 6 of appendix A–4 of this part, ASME PTC 19.10–1981 (incorporated by reference—see § 60.17) may be used.

§ 60.5408a What is an optional procedure for measuring hydrogen sulfide in acid gas—Tutwiler Procedure?

The Tutwiler procedure may be found in the Gas Engineers Handbook, Fuel Gas Engineering practices, The Industrial Press, 93 Worth Street, New York, NY, 1966, First Edition, Second Printing, page 6/25 (Docket A–80–20–A, Entry II–I–67).

(a) When an instantaneous sample is desired and H_2S concentration is 10 grains per 1000 cubic foot or more, a 100 ml Tutwiler burette is used. For concentrations less than 10 grains, a 500 ml Tutwiler burette and more dilute solutions are used. In principle, this method consists of titrating hydrogen sulfide in a gas sample directly with a standard solution of iodine.

(b) *Apparatus.* (See Figure 1 of this subpart) A 100 or 500 ml capacity Tutwiler burette, with two-way glass stopcock at bottom and three-way stopcock at top which connect either with inlet tubulature or glass-stoppered cylinder, 10 ml capacity, graduated in 0.1 ml subdivision; rubber tubing connecting burette with leveling bottle.

(c) *Reagents.* (1) Iodine stock solution, 0.1N. Weight 12.7 g iodine, and 20 to 25 g cp potassium iodide (KI) for each liter of solution. Dissolve KI in as little water as necessary; dissolve iodine in concentrated KI solution, make up to proper volume, and store in glass-stoppered brown glass bottle.

(2) Standard iodine solution, 1 ml = 0.001771 g I. Transfer 33.7 ml of above 0.1N stock solution into a 250 ml volumetric flask; add water to mark and mix well. Then, for 100 ml sample of gas, 1 ml of standard iodine solution is equivalent to 100 grains H_2S per cubic feet of gas.

(3) Starch solution. Rub into a thin paste about one teaspoonful of wheat starch with a little water; pour into about a pint of boiling water; stir; let cool and decant off clear solution. Make fresh solution every few days.

(d) *Procedure.* Fill leveling bulb with starch solution. Raise (L), open cock (G), open (F) to (A), and close (F) when solutions starts to run out of gas inlet. Close (G). Purge gas sampling line and connect with (A). Lower (L) and open (F) and (G). When liquid level is several ml past the 100 ml mark, close (G) and (F), and disconnect sampling tube. Open (G) and bring starch solution to 100 ml mark by raising (L); then close (G). Open (F) momentarily, to bring gas in burette to atmospheric pressure, and close (F). Open (G), bring liquid level down to 10 ml mark by lowering (L). Close (G), clamp rubber tubing near (E) and disconnect it from burette. Rinse graduated cylinder with a standard iodine solution (0.00171 g I per ml); fill cylinder and record reading. Introduce successive small amounts of iodine through (F); shake well after each addition; continue until a faint permanent blue color is obtained. Record reading; subtract from previous reading, and call difference D.

(e) With every fresh stock of starch solution perform a blank test as follows: Introduce fresh starch solution into burette up to 100 ml mark. Close (F) and (G). Lower (L) and open (G). When liquid level reaches the 10 ml mark, close (G). With air in burette, titrate as during a test and up to same end point. Call ml of iodine used C. Then, Grains H_2S per 100 cubic foot of gas = 100 (D–C)

(f) Greater sensitivity can be attained if a 500 ml capacity Tutwiler burette is used with a more dilute (0.001N) iodine solution. Concentrations less than 1.0 grains per 100 cubic foot can be determined in this way. Usually, the starch-iodine end point is much less distinct, and a blank determination of end point, with H_2S-free gas or air, is required.

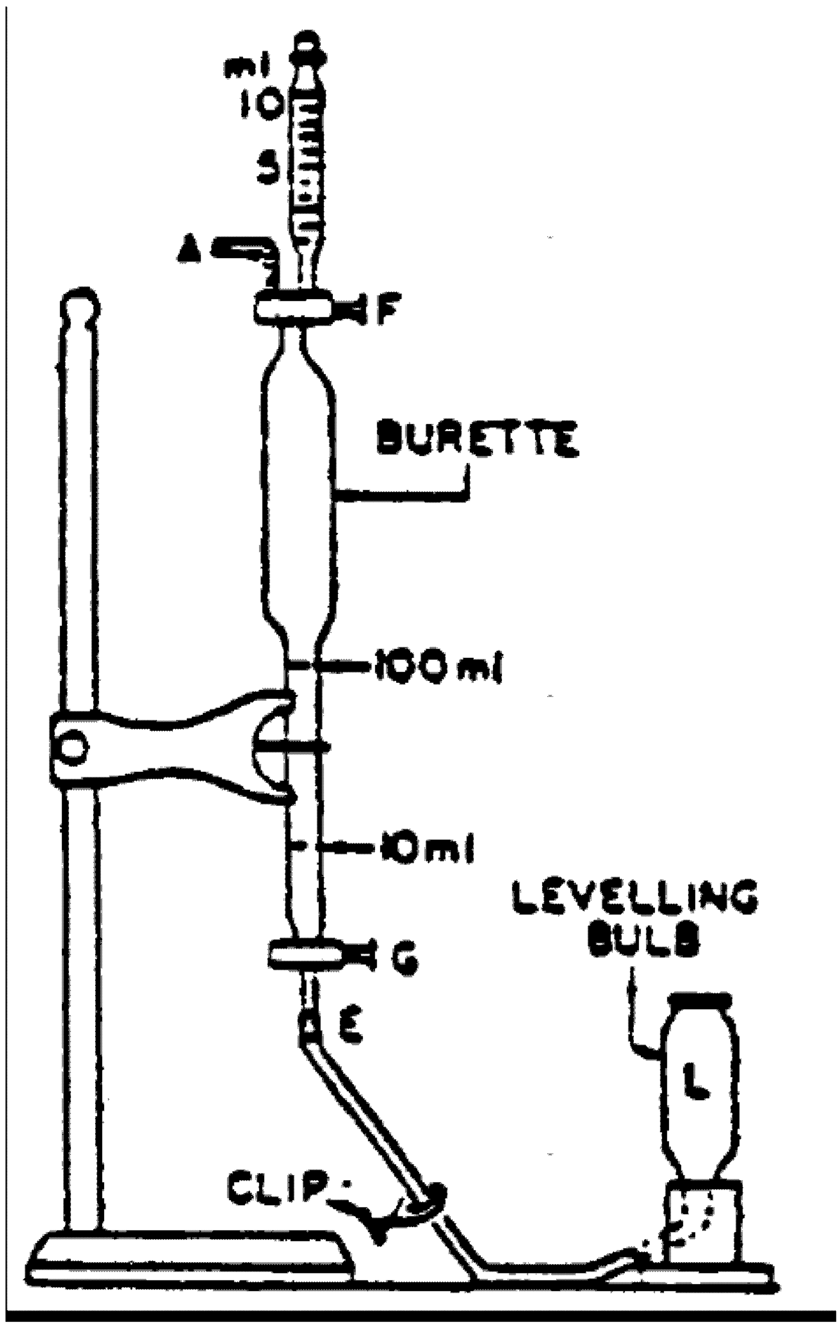

Figure 1. Tutwiler burette (lettered items mentioned in text).

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

You must determine initial compliance with the standards for each affected facility using the requirements in paragraphs (a) through (j) of this section. The initial compliance period begins on [date 60 days after publication of final rule in the **Federal Register**], or upon initial startup, whichever is later, and ends no later than 1 year after the initial startup date for your affected facility or no later than 1 year after [date 60 days after publication of final rule in the **Federal Register**]. The initial compliance period may be less than one full year.

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

(1) You must submit the notification required in § 60.5420a(a)(2).

(2) You must submit the initial annual report for your well affected facility as required in § 60.5420a(b).

(3) You must maintain a log of records as specified in § 60.5420a(c)(1)(i) through (iv) for each well completion operation conducted during the initial compliance period.

(4) For each well affected facility subject to both § 60.5375a(a)(1) and (3), as an alternative to retaining the records specified in § 60.5420a(c)(1)(i) through (iv), you may maintain records of one or more digital photographs with the date the photograph was taken and the latitude and longitude of the well site imbedded within or stored with the digital file showing the equipment for storing or re-injecting recovered liquid, equipment for routing recovered gas to the gas flow line and the completion combustion device (if applicable) connected to and operating at each well completion operation that occurred during the initial compliance period. As an alternative to imbedded latitude and longitude within the digital photograph, the digital photograph may consist of a photograph of the equipment connected and operating at each well completion operation with a photograph of a separately operating GIS device within the same digital picture, provided the latitude and longitude output of the GIS unit can be clearly read in the digital photograph.

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

(2) If you use a control device to reduce emissions, you must equip the wet seal fluid degassing system with a cover that meets the requirements of § 60.5411a(b) that is connected through a closed vent system that meets the requirements of § 60.5411a(a) and is routed to a control device that meets the conditions specified in § 60.5412a(a), (b) and (c). As an alternative to routing the closed vent system to a control device, you may route the closed vent system to a process that reduces VOC emissions by at least 95.0 percent.

(3) You must conduct an initial performance test as required in § 60.5413a within 180 days after initial startup or by [date 60 days after publication of final rule in the **Federal Register**], whichever is later, and you must comply with the continuous compliance requirements in § 60.5415a(b)(1) through (3).

(4) You must conduct the initial inspections required in § 60.5416a(a) and (b).

(5) You must install and operate the continuous parameter monitoring systems in accordance with § 60.5417a(a) through (g), as applicable.

(6) You must submit the notifications required in 60.7(a)(1), (3), and (4).

(7) You must submit the initial annual report for your centrifugal compressor affected facility as required in § 60.5420a(b) for each centrifugal compressor affected facility.

(8) You must maintain the records as specified in § 60.5420a(c).

(c) To achieve initial compliance with the standards for each reciprocating compressor affected facility you must comply with paragraphs (c)(1) through (4) of this section.

(1) If complying with § 60.5385a(a)(1) or (2), during the initial compliance period, you must continuously monitor the number of hours of operation or track the number of months since the last rod packing replacement.

(2) If complying with § 60.5385a(a)(3), you must operate the rod packing emissions collection system under negative pressure and route emissions to a process through a closed vent system that meets the requirements of § 60.5411a(a).

(3) You must submit the initial annual report for your reciprocating compressor as required in § 60.5420a(b).

(4) You must maintain the records as specified in § 60.5420a(c) for each reciprocating compressor affected facility.

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

(1) You must demonstrate initial compliance by maintaining records as specified in § 60.5420a(c)(4)(ii) of your determination that the use of a pneumatic controller affected facility with a bleed rate greater than the applicable standard is required as specified in § 60.5390a(a).

(2) You own or operate a pneumatic controller affected facility located at a natural gas processing plant and your pneumatic controller is driven by a gas other than natural gas and therefore emits zero natural gas.

(3) You own or operate a pneumatic controller affected facility located other than at a natural gas processing plant and the manufacturer's design specifications indicate that the controller emits less than or equal to 6 standard cubic feet of gas per hour.

(4) You must tag each new pneumatic controller affected facility according to the requirements of § 60.5390a(b)(2) or (c)(2).

(5) You must include the information in paragraph (d)(1) of this section and a listing of the pneumatic controller affected facilities specified in paragraphs (d)(2) and (3) of this section in the initial annual report submitted for your pneumatic controller affected facilities constructed, modified or reconstructed during the period covered by the annual report according to the requirements of § 60.5420a(b).

(6) You must maintain the records as specified in § 60.5420a(c) for each pneumatic controller affected facility.

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

(1) You own or operate a pneumatic pump affected facility located at a natural gas processing plant and your pneumatic pump is driven by a gas other than natural gas and therefore emits zero natural gas.

(2) You own or operate a pneumatic pump affected facility located other than at a natural gas processing plant and your pneumatic pump is controlled by at least 95 percent.

(3) You own or operate a pneumatic pump affected facility located other

than at a natural gas processing plant and your pneumatic pump is not controlled by at least 95 percent because a control device is not available at the site, you must submit the certification in 60.5420a(b)(8)(i).

(4) You must tag each new pneumatic pump affected facility according to the requirements of § 60.5393a(a)(2) or (b)(3).

(5) You must include a listing of the pneumatic pump affected facilities specified in paragraphs (e)(1) through (3) of this section in the initial annual report submitted for your pneumatic pump affected facilities constructed, modified or reconstructed during the period covered by the annual report according to the requirements of § 60.5420a(b).

(6) You must maintain the records as specified in § 60.5420a(c) for each pneumatic pump affected facility.

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

(g) For sweetening unit affected facilities at onshore natural gas processing plants, initial compliance is demonstrated according to paragraphs (g)(1) through (3) of this section.

(1) To determine compliance with the standards for SO_2 specified in § 60.5405a(a), during the initial performance test as required by § 60.8, the minimum required sulfur dioxide emission reduction efficiency (Z_i) is compared to the emission reduction efficiency (R) achieved by the sulfur recovery technology as specified in paragraphs (g)(1)(i) and (ii) of this section.

(i) If $R \geq Z_i$, your affected facility is in compliance.

(ii) If $R < Z_i$, your affected facility is not in compliance.

(2) The emission reduction efficiency (R) achieved by the sulfur reduction technology must be determined using the procedures in § 60.5406a(c)(1).

(3) You have submitted the results of paragraphs (g)(1) and (2) of this section in the initial annual report submitted for your sweetening unit affected facilities at onshore natural gas processing plants.

(h) For each storage vessel affected facility, you must comply with paragraphs (h)(1) through (6) of this section. You must demonstrate initial compliance by [date 60 days after publication of final rule in the **Federal Register**], or within 60 days after startup, whichever is later.

(1) You must determine the potential VOC emission rate as specified in § 60.5365a(e).

(2) You must reduce VOC emissions in accordance with § 60.5395a(a).

(3) If you use a control device to reduce emissions, you must equip the storage vessel with a cover that meets the requirements of § 60.5411a(b) and is connected through a closed vent system that meets the requirements of § 60.5411a(c) to a control device that meets the conditions specified in § 60.5412a(d) within 60 days after startup for storage vessels constructed, modified or reconstructed at well sites with no other wells in production, or upon startup for storage vessels constructed, modified or reconstructed at well sites with one or more wells already in production.

(4) You must conduct an initial performance test as required in § 60.5413a within 180 days after initial startup or within 180 days of [date 60 days after publication of final rule in the **Federal Register**], whichever is later, and you must comply with the continuous compliance requirements in § 60.5415a(e).

(5) You must submit the information required for your storage vessel affected facility as specified in § 60.5420a(b).

(6) You must maintain the records required for your storage vessel affected facility, as specified in § 60.5420a(c) for each storage vessel affected facility.

(i) For each storage vessel affected facility, you must submit the notification specified in § 60.5395a(b)(2) with the initial annual report specified in § 60.5420a(b).

(j) To achieve initial compliance with the fugitive emission standards for each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a compressor station, you must comply with paragraphs (j)(1) through (5) of this section.

(1) You must develop a fugitive emissions monitoring plan for each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a compressor station as required in § 60.5397a(a).

(2) You must conduct an initial monitoring survey as required in § 60.5397a(f).

(3) You must maintain the records specified in § 60.5420a(c).

(4) You must repair each identified source of fugitive emissions for each affected facility as required in § 60.5397a(j).

(5) You must submit the initial annual report for each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a compressor station as required in § 60.5420a(b).

§ 60.5411a What additional requirements must I meet to determine initial compliance for my covers and closed vent systems routing emissions from centrifugal compressor wet seal fluid degassing systems, reciprocating compressors, pneumatic pumps and storage vessels?

You must meet the applicable requirements of this section for each cover and closed vent system used to comply with the emission standards for your centrifugal compressor wet seal degassing systems, reciprocating compressors, pneumatic pumps and storage vessels.

(a) *Closed vent system requirements for reciprocating compressors, centrifugal compressor wet seal degassing systems and pneumatic pumps.* (1) You must design the closed vent system to route all gases, vapors, and fumes emitted from the reciprocating compressor rod packing emissions collection system, the wet seal fluid degassing system or pneumatic pump to a control device or to a process that meets the requirements specified in § 60.5412a(a) through (c).

(2) You must design and operate the closed vent system with no detectable emissions as demonstrated by § 60.5416a(b).

(3) You must meet the requirements specified in paragraphs (a)(3)(i) and (ii) of this section if the closed vent system contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the control device.

(i) Except as provided in paragraph (a)(3)(ii) of this section, you must comply with either paragraph (a)(3)(i)(A) or (B) of this section for each bypass device.

(A) You must properly install, calibrate, maintain, and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere. Set the flow indicator to trigger an audible and visible alarm, and initiate notification via remote alarm to the nearest field office, when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere. You must maintain records of each time the alarm is activated according to § 60.5420a(c)(8).

(B) You must secure the bypass device valve installed at the inlet to the bypass device in the non-diverting position using a car-seal or a lock-and-key type configuration.

(ii) Low leg drains, high point bleeds, analyzer vents, open-ended valves or lines, and safety devices are not subject to the requirements of paragraph (a)(3)(i) of this section.

(b) *Cover requirements for storage vessels and centrifugal compressor wet seal fluid degassing systems.* (1) The cover and all openings on the cover (*e.g.,* access hatches, sampling ports, pressure relief devices and gauge wells) shall form a continuous impermeable barrier over the entire surface area of the liquid in the storage vessel or wet seal fluid degassing system.

(2) Each cover opening shall be secured in a closed, sealed position (*e.g.,* covered by a gasketed lid or cap) whenever material is in the unit on which the cover is installed except during those times when it is necessary to use an opening as follows:

(i) To add material to, or remove material from the unit (this includes openings necessary to equalize or balance the internal pressure of the unit following changes in the level of the material in the unit);

(ii) To inspect or sample the material in the unit;

(iii) To inspect, maintain, repair, or replace equipment located inside the unit; or

(iv) To vent liquids, gases, or fumes from the unit through a closed-vent system designed and operated in accordance with the requirements of paragraph (a) or (c) of this section to a control device or to a process.

(3) Each storage vessel thief hatch shall be equipped, maintained and operated with a weighted mechanism or equivalent, to ensure that the lid remains properly seated and sealed under normal operating conditions, including such times when working, standing/breathing, and flash emissions may be generated. You must select gasket material for the hatch based on composition of the fluid in the storage vessel and weather conditions.

(c) *Closed vent system requirements for storage vessel affected facilities using a control device or routing emissions to a process.* (1) You must design the closed vent system to route all gases, vapors, and fumes emitted from the material in the storage vessel to a control device that meets the requirements specified in § 60.5412a(c) and (d), or to a process.

(2) You must design and operate a closed vent system with no detectable emissions, as determined using olfactory, visual and auditory inspections. Each closed vent system that routes emissions to a process must be operational 95 percent of the year or greater.

(3) You must meet the requirements specified in paragraphs (c)(3)(i) and (ii) of this section if the closed vent system contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the control device or to a process.

(i) Except as provided in paragraph (c)(3)(ii) of this section, you must comply with either paragraph (c)(3)(i)(A) or (B) of this section for each bypass device.

(A) You must properly install, calibrate, maintain, and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere. Set the flow indicator to trigger and audible and visible alarm, and initiate notification via remote alarm to the nearest field office, when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere. You must maintain records of each time the alarm is sounded according to § 60.5420a(c)(8).

(B) You must secure the bypass device valve installed at the inlet to the bypass device in the non-diverting position using a car-seal or a lock-and-key type configuration.

(ii) Low leg drains, high point bleeds, analyzer vents, open-ended valves or lines, and safety devices are not subject to the requirements of paragraph (c)(3)(i) of this section.

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

You must meet the applicable requirements of this section for each control device used to comply with the emission standards for your centrifugal compressor affected facility, pneumatic pump affected facility, or storage vessel affected facility.

(a) Each control device used to meet the emission reduction standard in § 60.5380a(a)(1) for your centrifugal compressor affected facility or § 60.5393a(b)(1) for your pneumatic pump must be installed according to paragraphs (a)(1) through (3) of this section. As an alternative, you may install a control device model tested under § 60.5413a(d), which meets the criteria in § 60.5413a(d)(11) and § 60.5413a(e).

(1) Each combustion device (*e.g.,* thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) must be designed and operated in accordance with one of the performance requirements specified in paragraphs (a)(1)(i) through (iv) of this section.

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

(ii) You must reduce the concentration of TOC in the exhaust gases at the outlet to the device to a level equal to or less than 600 parts per million by volume as propane on a dry basis corrected to 3 percent oxygen as determined in accordance with the requirements of § 60.5413a.

(iii) You must operate at a minimum temperature of 760 °C for a control device that can demonstrate a uniform combustion zone temperature during the performance test conducted under § 60.5413a.

(iv) If a boiler or process heater is used as the control device, then you must introduce the vent stream into the flame zone of the boiler or process heater.

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

(3) You must design and operate a flare in accordance with the requirements of § 60.5413a(a)(1).

(b) You must operate each control device installed on your centrifugal compressor or pneumatic pump affected facility in accordance with the requirements specified in paragraphs (b)(1) and (2) of this section.

(1) You must operate each control device used to comply with this subpart at all times when gases, vapors, and fumes are vented from the wet seal fluid degassing system affected facility as required under § 60.5380a(a), or from the pneumatic pump as required under § 60.5393a(b)(1), through the closed vent system to the control device. You may vent more than one affected facility to a control device used to comply with this subpart.

(2) For each control device monitored in accordance with the requirements of § 60.5417a(a) through (g), you must demonstrate compliance according to the requirements of § 60.5415a(b)(2), as applicable.

(c) For each carbon adsorption system used as a control device to meet the requirements of paragraph (a)(2) or (d)(2) of this section, you must manage the carbon in accordance with the requirements specified in paragraphs (c)(1) or (2) of this section.

(1) Following the initial startup of the control device, you must replace all carbon in the control device with fresh carbon on a regular, predetermined time interval that is no longer than the carbon service life established according to § 60.5413a(c)(2) or (3) or according to the design required in paragraph (d)(2) of this section, for the carbon adsorption system. You must maintain records identifying the schedule for replacement and records of each carbon replacement as required in § 60.5420a(c)(10) and (12).

(2) You must either regenerate, reactivate, or burn the spent carbon removed from the carbon adsorption system in one of the units specified in paragraphs (c)(2)(i) through (vii) of this section.

(i) Regenerate or reactivate the spent carbon in a thermal treatment unit for which you have been issued a final permit under 40 CFR part 270 that implements the requirements of 40 CFR part 264, subpart X.

(ii) Regenerate or reactivate the spent carbon in a thermal treatment unit equipped with and operating air emission controls in accordance with this section.

(iii) Regenerate or reactivate the spent carbon in a thermal treatment unit equipped with and operating organic air emission controls in accordance with an emissions standard for VOC under another subpart in 40 CFR part 60 or this part.

(iv) Burn the spent carbon in a hazardous waste incinerator for which the owner or operator has been issued a final permit under 40 CFR part 270 that implements the requirements of 40 CFR part 264, subpart O.

(v) Burn the spent carbon in a hazardous waste incinerator which you have designed and operated in accordance with the requirements of 40 CFR part 265, subpart O.

(vi) Burn the spent carbon in a boiler or industrial furnace for which you have been issued a final permit under 40 CFR part 270 that implements the requirements of 40 CFR part 266, subpart H.

(vii) Burn the spent carbon in a boiler or industrial furnace that you have designed and operated in accordance with the interim status requirements of 40 CFR part 266, subpart H.

(d) Each control device used to meet the emission reduction standard in § 60.5395a(a) for your storage vessel affected facility must be installed according to paragraphs (d)(1) through (3) of this section, as applicable. As an alternative to paragraph (d)(1) of this section, you may install a control device model tested under § 60.5413a(d), which meets the criteria in § 60.5413a(d)(11) and § 60.5413a(e).

(1) For each enclosed combustion control device (e.g., thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) you must meet the requirements in paragraphs (d)(1)(i) through (iv) of this section.

(i) Ensure that each enclosed combustion control device is maintained in a leak free condition.

(ii) Install and operate a continuous burning pilot flame.

(iii) Operate the combustion control device with no visible emissions, except for periods not to exceed a total of 1 minute during any 15 minute period. A visible emissions test using section 11 of EPA Method 22 of appendix A–7 of this part must be performed at least once every calendar month, separated by at least 15 days between each test. The observation period shall be 15 minutes. Devices failing the visible emissions test must follow manufacturer's repair instructions, if available, or best combustion engineering practice as outlined in the unit inspection and maintenance plan, to return the unit to compliant operation. All inspection, repair and maintenance activities for each unit must be recorded in a maintenance and repair log and must be available for inspection. Following return to operation from maintenance or repair activity, each device must pass a Method 22 of appendix A–7 of this part visual observation as described in this paragraph.

(iv) Each combustion control device (*e.g.*, thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) must be designed and operated in accordance with one of the performance requirements specified in paragraphs (A) through (D) of this section.

(A) You must reduce the mass content of methane and VOC in the gases vented to the device by 95.0 percent by weight or greater as determined in accordance with the requirements of § 60.5413a.

(B) You must reduce the concentration of TOC in the exhaust gases at the outlet to the device to a level equal to or less than 600 parts per million by volume as propane on a dry basis corrected to 3 percent oxygen as determined in accordance with the requirements of § 60.5413a.

(C) You must operate at a minimum temperature of 760 °C for a control device that can demonstrate a uniform combustion zone temperature during the performance test conducted under § 60.5413a.

(D) If a boiler or process heater is used as the control device, then you must introduce the vent stream into the flame zone of the boiler or process heater.

(2) Each vapor recovery device (*e.g.*, carbon adsorption system or condenser) or other non-destructive control device must be designed and operated to reduce the mass content of methane and VOC in the gases vented to the device by 95.0 percent by weight or greater. A carbon replacement schedule must be included in the design of the carbon adsorption system.

(3) You must operate each control device used to comply with this subpart at all times when gases, vapors, and fumes are vented from the storage vessel affected facility through the closed vent system to the control device. You may vent more than one affected facility to a control device used to comply with this subpart.

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

This section applies to the performance testing of control devices used to demonstrate compliance with the emissions standards for your centrifugal compressor affected facility, pneumatic pump affected facility, or storage vessel affected facility. You must demonstrate that a control device achieves the performance requirements of § 60.5412a(a) or (d) using the performance test methods and procedures specified in this section. For condensers and carbon adsorbers, you may use a design analysis as specified in paragraph (c) of this section in lieu of complying with paragraph (b) of this section. In addition, this section contains the requirements for enclosed combustion control device performance tests conducted by the manufacturer applicable to storage vessel, centrifugal compressor and pneumatic pump affected facilities.

(a) *Performance test exemptions.* You are exempt from the requirements to conduct performance tests and design analyses if you use any of the control devices described in paragraphs (a)(1) through (7) of this section.

(1) A flare that is designed and operated in accordance with § 60.18(b). You must conduct the compliance determination using Method 22 of appendix A–7 of this part to determine visible emissions.

(2) A boiler or process heater with a design heat input capacity of 44 megawatts or greater.

(3) A boiler or process heater into which the vent stream is introduced with the primary fuel or is used as the primary fuel.

(4) A boiler or process heater burning hazardous waste for which you have either been issued a final permit under 40 CFR part 270 and comply with the requirements of 40 CFR part 266, subpart H; or you have certified compliance with the interim status requirements of 40 CFR part 266, subpart H.

(5) A hazardous waste incinerator for which you have been issued a final permit under 40 CFR part 270 and comply with the requirements of 40 CFR part 264, subpart O; or you have certified compliance with the interim status requirements of 40 CFR part 265, subpart O.

(6) A performance test is waived in accordance with § 60.8(b).

(7) A control device whose model can be demonstrated to meet the performance requirements of § 60.5412a(a) or (d) through a performance test conducted by the manufacturer, as specified in paragraph (d) of this section.

(b) *Test methods and procedures.* You must use the test methods and procedures specified in paragraphs (b)(1) through (5) of this section, as applicable, for each performance test conducted to demonstrate that a control device meets the requirements of § 60.5412a(a) or (d). You must conduct the initial and periodic performance tests according to the schedule specified in paragraph (b)(5) of this section.

(1) You must use Method 1 or 1A of appendix A–1 of this part, as appropriate, to select the sampling sites specified in paragraphs (b)(1)(i) and (ii) of this section. Any references to particulate mentioned in Methods 1 and 1A do not apply to this section.

(i) Sampling sites must be located at the inlet of the first control device, and at the outlet of the final control device, to determine compliance with the control device percent reduction requirement specified in § 60.5412a(a)(1)(i) or (a)(2).

(ii) The sampling site must be located at the outlet of the combustion device to determine compliance with the enclosed combustion control device total TOC concentration limit specified in § 60.5412a(a)(1)(ii).

(2) You must determine the gas volumetric flowrate using Method 2, 2A, 2C, or 2D of appendix A–2 of this part, as appropriate.

(3) To determine compliance with the control device percent reduction performance requirement in § 60.5412a(a)(1)(i), (a)(2) or (d)(1)(i)(A), you must use Method 25A of appendix A–7 of this part. You must use the procedures in paragraphs (b)(3)(i) through (iv) of this section to calculate percent reduction efficiency.

(i) For each run, you must take either an integrated sample or a minimum of four grab samples per hour. If grab sampling is used, then the samples must be taken at approximately equal intervals in time, such as 15-minute intervals during the run.

(ii) You must compute the mass rate of TOC (minus methane and ethane) using the equations and procedures specified in paragraphs (b)(3)(ii)(A) and (B) of this section.

(A) You must use the following equations:

$$E_i = K_2\left(\sum_{j=1}^{n} C_{ij}M_{ij}\right)Q_i$$

$$E_o = K_2\left(\sum_{j=1}^{n} C_{oj}M_{oj}\right)Q_o$$

Where:

E_i, E_o = Mass rate of TOC (minus methane and ethane) at the inlet and outlet of the control device, respectively, dry basis, kilogram per hour.

K_2 = Constant, 2.494×10^{-6} (parts per million) (gram-mole per standard cubic meter) (kilogram/gram) (minute/hour), where standard temperature (gram-mole per standard cubic meter) is 20 °C.

C_{ij}, C_{oj} = Concentration of sample component j of the gas stream at the inlet and outlet of the control device, respectively, dry basis, parts per million by volume.

M_{ij}, M_{oj} = Molecular weight of sample component j of the gas stream at the inlet and outlet of the control device, respectively, gram/gram-mole.

Q_i, Q_o = Flowrate of gas stream at the inlet and outlet of the control device, respectively, dry standard cubic meter per minute.

n = Number of components in sample.

(B) When calculating the TOC mass rate, you must sum all organic compounds (minus methane and ethane) measured by Method 25A of appendix A–7 of this part using the equations in paragraph (b)(3)(ii)(A) of this section.

(iii) You must calculate the percent reduction in TOC (minus methane and ethane) as follows:

$$R_{cd} = \frac{E_i - E_o}{E_i} * 100\%$$

Where:

R_{cd} = Control efficiency of control device, percent.

E_i = Mass rate of TOC (minus methane and ethane) at the inlet to the control device as calculated under paragraph (b)(3)(ii) of this section, kilograms TOC per hour or kilograms HAP per hour.

E_o = Mass rate of TOC (minus methane and ethane) at the outlet of the control device, as calculated under paragraph (b)(3)(ii) of this section, kilograms TOC per hour per hour.

(iv) If the vent stream entering a boiler or process heater with a design capacity less than 44 megawatts is introduced with the combustion air or as a secondary fuel, you must determine the weight-percent reduction of total TOC (minus methane and ethane) across the device by comparing the TOC (minus methane and ethane) in all combusted vent streams and primary and secondary fuels with the TOC (minus methane and ethane) exiting the device, respectively.

(4) You must use Method 25A of appendix A–7 of this part to measure TOC (minus methane and ethane) to determine compliance with the enclosed combustion control device total VOC concentration limit specified in § 60.5412a(a)(1)(ii) or (d)(1)(iv)(B). You must calculate parts per million by volume concentration and correct to 3 percent oxygen, using the procedures in paragraphs (b)(4)(i) through (iii) of this section.

(i) For each run, you must take either an integrated sample or a minimum of four grab samples per hour. If grab sampling is used, then the samples must be taken at approximately equal intervals in time, such as 15-minute intervals during the run.

(ii) You must calculate the TOC concentration for each run as follows:

$$C_{TOC} = \sum_{i=1}^{x} \frac{\left(\sum_{j=i}^{n} C_{ji}\right)}{x}$$

Where:

C_{TOC} = Concentration of total organic compounds minus methane and ethane, dry basis, parts per million by volume.

C_{ji} = Concentration of sample component j of sample i, dry basis, parts per million by volume.

n = Number of components in the sample.

x = Number of samples in the sample run.

(iii) You must correct the TOC concentration to 3 percent oxygen as specified in paragraphs (b)(4)(iii)(A) and (B) of this section.

(A) You must use the emission rate correction factor for excess air, integrated sampling and analysis procedures of Method 3A or 3B of appendix A–2 of this part, ASTM D6522–00 (Reapproved 2005), or ASME/

ANSI PTC 19.10–1981, Part 10 (manual portion only) (incorporated by reference as specified in § 60.17) to determine the oxygen concentration. The samples must be taken during the same time that the samples are taken for determining TOC concentration.

(B) You must correct the TOC concentration for percent oxygen as follows:

$$C_c = C_m \left(\frac{17.9}{20.9 - \%O_{2d}} \right)$$

Where:

C_c = TOC concentration corrected to 3 percent oxygen, dry basis, parts per million by volume.

C_m = TOC concentration, dry basis, parts per million by volume.

$\%O_{2d}$ = Concentration of oxygen, dry basis, percent by volume.

(5) You must conduct performance tests according to the schedule specified in paragraphs (b)(5)(i) and (ii) of this section.

(i) You must conduct an initial performance test within 180 days after initial startup for your affected facility. You must submit the performance test results as required in § 60.5420a(b)(9).

(ii) You must conduct periodic performance tests for all control devices required to conduct initial performance tests except as specified in paragraphs (b)(5)(ii)(A) and (B) of this section. You must conduct the first periodic performance test no later than 60 months after the initial performance test required in paragraph (b)(5)(i) of this section. You must conduct subsequent periodic performance tests at intervals no longer than 60 months following the previous periodic performance test or whenever you desire to establish a new operating limit. You must submit the periodic performance test results as specified in § 60.5420a(b)(9). Combustion control devices meeting the criteria in either paragraph (b)(5)(ii)(A) or (B) of this section are not required to conduct periodic performance tests.

(A) A control device whose model is tested under, and meets the criteria of paragraph (d) of this section.

(B) A combustion control device tested under paragraph (b) of this section that meets the outlet TOC performance level specified in § 60.5412a(a)(1)(ii) or (d)(1)(iv)(B) and that establishes a correlation between firebox or combustion chamber temperature and the TOC performance level.

(c) *Control device design analysis to meet the requirements of § 60.5412a(a)(2) or (d)(2).* (1) For a condenser, the design analysis must include an analysis of the vent stream composition, constituent concentrations, flowrate, relative humidity, and temperature, and must establish the design outlet organic compound concentration level, design average temperature of the condenser exhaust vent stream, and the design average temperatures of the coolant fluid at the condenser inlet and outlet.

(2) For a regenerable carbon adsorption system, the design analysis shall include the vent stream composition, constituent concentrations, flowrate, relative humidity, and temperature, and shall establish the design exhaust vent stream organic compound concentration level, adsorption cycle time, number and capacity of carbon beds, type and working capacity of activated carbon used for the carbon beds, design total regeneration stream flow over the period of each complete carbon bed regeneration cycle, design carbon bed temperature after regeneration, design carbon bed regeneration time, and design service life of the carbon.

(3) For a nonregenerable carbon adsorption system, such as a carbon canister, the design analysis shall include the vent stream composition, constituent concentrations, flowrate, relative humidity, and temperature, and shall establish the design exhaust vent stream organic compound concentration level, capacity of the carbon bed, type and working capacity of activated carbon used for the carbon bed, and design carbon replacement interval based on the total carbon working capacity of the control device and source operating schedule. In addition, these systems shall incorporate dual carbon canisters in case of emission breakthrough occurring in one canister.

(4) If you and the Administrator do not agree on a demonstration of control device performance using a design analysis, then you must perform a performance test in accordance with the requirements of paragraph (b) of this section to resolve the disagreement. The Administrator may choose to have an authorized representative observe the performance test.

(d) *Performance testing for combustion control devices—manufacturers' performance test.* (1) This paragraph applies to the performance testing of a combustion control device conducted by the device manufacturer. The manufacturer must demonstrate that a specific model of control device achieves the performance requirements in paragraph (d)(11) of this section by conducting a performance test as specified in paragraphs (d)(2) through (10) of this section. You must submit a test report for each combustion control device in accordance with the requirements in paragraph (d)(12) of this section.

(2) Performance testing must consist of three 1-hour (or longer) test runs for each of the four firing rate settings specified in paragraphs (d)(2)(i) through (iv) of this section, making a total of 12 test runs per test. Propene (propylene) gas must be used for the testing fuel. All fuel analyses must be performed by an independent third-party laboratory (not affiliated with the control device manufacturer or fuel supplier).

(i) 90–100 percent of maximum design rate (fixed rate).

(ii) 70–100–70 percent (ramp up, ramp down). Begin the test at 70 percent of the maximum design rate. During the first 5 minutes, incrementally ramp the firing rate to 100 percent of the maximum design rate. Hold at 100 percent for 5 minutes. In the 10–15 minute time range, incrementally ramp back down to 70 percent of the maximum design rate. Repeat three more times for a total of 60 minutes of sampling.

(iii) 30–70–30 percent (ramp up, ramp down). Begin the test at 30 percent of the maximum design rate. During the first 5 minutes, incrementally ramp the firing rate to 70 percent of the maximum design rate. Hold at 70 percent for 5 minutes. In the 10–15 minute time range, incrementally ramp back down to 30 percent of the maximum design rate. Repeat three more times for a total of 60 minutes of sampling.

(iv) 0–30–0 percent (ramp up, ramp down). Begin the test at the minimum firing rate. During the first 5 minutes, incrementally ramp the firing rate to 30 percent of the maximum design rate. Hold at 30 percent for 5 minutes. In the 10–15 minute time range, incrementally ramp back down to the minimum firing rate. Repeat three more times for a total of 60 minutes of sampling.

(3) All models employing multiple enclosures must be tested simultaneously and with all burners operational. Results must be reported for each enclosure individually and for the average of the emissions from all interconnected combustion enclosures/chambers. Control device operating data must be collected continuously throughout the performance test using an electronic Data Acquisition System. A graphic presentation or strip chart of the control device operating data and emissions test data must be included in the test report in accordance with paragraph (d)(12) of this section. Inlet fuel meter data may be manually recorded provided that all inlet fuel data readings are included in the final report.

(4) Inlet testing must be conducted as specified in paragraphs (d)(4)(i) through (ii) of this section.

(i) The inlet gas flow metering system must be located in accordance with Method 2A of appendix A–1 of this part (or other approved procedure) to measure inlet gas flow rate at the control device inlet location. You must position the fitting for filling fuel sample containers a minimum of eight pipe diameters upstream of any inlet gas flow monitoring meter.

(ii) Inlet flow rate must be determined using Method 2A of appendix A–1 of this part. Record the start and stop reading for each 60-minute THC test. Record the gas pressure and temperature at 5-minute intervals throughout each 60-minute test.

(5) Inlet gas sampling must be conducted as specified in paragraphs (d)(5)(i) through (ii) of this section.

(i) At the inlet gas sampling location, securely connect a Silonite-coated stainless steel evacuated canister fitted with a flow controller sufficient to fill the canister over a 3-hour period. Filling must be conducted as specified in paragraphs (d)(5)(i)(A) through (C) of this section.

(A) Open the canister sampling valve at the beginning of each test run, and close the canister at the end of each test run.

(B) Fill one canister across the three test runs such that one composite fuel sample exists for each test condition.

(C) Label the canisters individually and record sample information on a chain of custody form.

(ii) Analyze each inlet gas sample using the methods in paragraphs (d)(5)(ii)(A) through (C) of this section. You must include the results in the test report required by paragraph (d)(12) of this section.

(A) Hydrocarbon compounds containing between one and five atoms of carbon plus benzene using ASTM D1945–03.

(B) Hydrogen (H2), carbon monoxide (CO), carbon dioxide (CO_2), nitrogen (N_2), oxygen (O_2) using ASTM D1945–03.

(C) Higher heating value using ASTM D3588–98 or ASTM D4891–89.

(6) Outlet testing must be conducted in accordance with the criteria in paragraphs (d)(6)(i) through (v) of this section.

(i) Sample and flow rate must be measured in accordance with paragraphs (d)(6)(i)(A) through (B) of this section.

(A) The outlet sampling location must be a minimum of four equivalent stack diameters downstream from the highest peak flame or any other flow disturbance, and a minimum of one equivalent stack diameter upstream of the exit or any other flow disturbance. A minimum of two sample ports must be used.

(B) Flow rate must be measured using Method 1 of appendix A–1 of this part for determining flow measurement traverse point location, and Method 2 of appendix A–1 of this part for measuring duct velocity. If low flow conditions are encountered (*i.e.*, velocity pressure differentials less than 0.05 inches of water) during the performance test, a more sensitive manometer must be used to obtain an accurate flow profile.

(ii) Molecular weight and excess air must be determined as specified in paragraph (d)(7) of this section.

(iii) Carbon monoxide must be determined as specified in paragraph (d)(8) of this section.

(iv) THC must be determined as specified in paragraph (d)(9) of this section.

(v) Visible emissions must be determined as specified in paragraph (d)(10) of this section.

(7) Molecular weight and excess air determination must be performed as specified in paragraphs (d)(7)(i) through (iii) of this section.

(i) An integrated bag sample must be collected during the moisture test required by Method 4 of appendix A–3 of this part following the procedure specified in (d)(7)(i)(A) and (B) of this section. Analyze the bag sample using a gas chromatograph-thermal conductivity detector (GC–TCD) analysis meeting the criteria in paragraphs (d)(7)(i)(C) and (D) of this section.

(A) Collect the integrated sample throughout the entire test, and collect representative volumes from each traverse location.

(B) Purge the sampling line with stack gas before opening the valve and beginning to fill the bag. Clearly label each bag and record sample information on a chain of custody form.

(C) The bag contents must be vigorously mixed prior to the gas chromatograph analysis.

(D) The GC–TCD calibration procedure in Method 3C of appendix A–2 of this part must be modified by using EPA Alt-045 as follows: For the initial calibration, triplicate injections of any single concentration must agree within 5 percent of their mean to be valid. The calibration response factor for a single concentration re-check must be within 10 percent of the original calibration response factor for that concentration. If this criterion is not met, repeat the initial calibration using at least three concentration levels.

(ii) Calculate and report the molecular weight of oxygen, carbon dioxide, methane, and nitrogen in the integrated bag sample and include in the test report specified in paragraph (d)(12) of this section. Moisture must be determined using Method 4 of appendix A–3 of this part. Traverse both ports with the sampling train required by Method 4 of appendix A–3 of this part during each test run. Ambient air must not be introduced into the integrated bag sample required by Method 3C of appendix A–2 of this part during the port change.

(iii) Excess air must be determined using resultant data from the EPA Method 3C tests and EPA Method 3B of appendix A–2 of this part, equation 3B–1, or ASME/ANSI PTC 19.10–1981, Part 10 (manual portion only) (incorporated by reference as specified in § 60.17).

(8) Carbon monoxide must be determined using Method 10 of appendix A–4 of this part. Run the test simultaneously with Method 25A of appendix A–7 of this part using the same sampling points. An instrument range of 0–10 parts per million by volume-dry (ppmvd) is recommended.

(9) Total hydrocarbon determination must be performed as specified by in paragraphs (d)(9)(i) through (vii) of this section.

(i) Conduct THC sampling using Method 25A of appendix A–7 of this part, except that the option for locating the probe in the center 10 percent of the stack is not allowed. The THC probe must be traversed to 16.7 percent, 50 percent, and 83.3 percent of the stack diameter during each test run.

(ii) A valid test must consist of three Method 25A tests, each no less than 60 minutes in duration.

(iii) A 0–10 parts per million by volume-wet (ppmvw) (as propane) measurement range is preferred; as an alternative a 0–30 ppmvw (as carbon) measurement range may be used.

(iv) Calibration gases must be propane in air and be certified through EPA Protocol 1—''EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards,'' September 1997, as amended August 25, 1999, EPA–600/R–97/121 (or more recent if updated since 1999).

(v) THC measurements must be reported in terms of ppmvw as propane.

(vi) THC results must be corrected to 3 percent CO_2, as measured by Method 3C of appendix A–2 of this part. You must use the following equation for this diluent concentration correction:

$$C_{corr} = C_{meas}\left(\frac{3}{CO_{2meas}}\right)$$

Where:

C_{meas} = The measured concentration of the pollutant.

CO_{2meas} = The measured concentration of the CO_2 diluent.

3 = The corrected reference concentration of CO_2 diluent.

C_{corr} = The corrected concentration of the pollutant.

(vii) Subtraction of methane or ethane from the THC data is not allowed in determining results.

(10) Visible emissions must be determined using Method 22 of appendix A–7 of this part. The test must be performed continuously during each test run. A digital color photograph of the exhaust point, taken from the position of the observer and annotated with date and time, must be taken once per test run and the 12 photos included in the test report specified in paragraph (d)(12) of this section.

(11) *Performance test criteria.* (i) The control device model tested must meet the criteria in paragraphs (d)(11)(i)(A) through (D) of this section. These criteria must be reported in the test report required by paragraph (d)(12) of this section.

(A) Results from Method 22 of appendix A–7 of this part determined under paragraph (d)(10) of this section with no indication of visible emissions.

(B) Average results from Method 25A of appendix A–7 of this part determined under paragraph (d)(9) of this section equal to or less than 10.0 ppmvw THC as propane corrected to 3.0 percent CO_2.

(C) Average CO emissions determined under paragraph (d)(8) of this section equal to or less than 10 parts ppmvd, corrected to 3.0 percent CO_2.

(D) Excess air determined under paragraph (d)(7) of this section equal to or greater than 150 percent.

(ii) The manufacturer must determine a maximum inlet gas flow rate which must not be exceeded for each control device model to achieve the criteria in paragraph (d)(11)(iii) of this section. The maximum inlet gas flow rate must be included in the test report required by paragraph (d)(12) of this section.

(iii) A control device meeting the criteria in paragraphs (d)(11)(i)(A) through (D) of this section must demonstrate a destruction efficiency of 95 percent for methane, if applicable, and VOC regulated under this subpart.

(12) The owner or operator of a combustion control device model tested under this paragraph must submit the information listed in paragraphs (d)(12)(i) through (vi) in the test report required by this section in accordance with § 60.5420a(b). Owners or operators who claim that any of the performance test information being submitted is confidential business information (CBI) must submit a complete file including information claimed to be CBI, on a compact disc, flash drive, or other commonly used electronic storage media to the EPA. The electronic media must be clearly marked as CBI and mailed to Attn: CBI Officer; OAQPS CBIO Room 521; 109 T.W. Alexander Drive; RTP, NC 27711. The same file with the CBI omitted must be submitted to *Oil_and_Gas_PT@EPA.GOV.*

(i) A full schematic of the control device and dimensions of the device components.

(ii) The maximum net heating value of the device.

(iii) The test fuel gas flow range (in both mass and volume). Include the maximum allowable inlet gas flow rate.

(iv) The air/stream injection/assist ranges, if used.

(v) The test conditions listed in paragraphs (d)(12)(v)(A) through (O) of this section, as applicable for the tested model.

(A) Fuel gas delivery pressure and temperature.

(B) Fuel gas moisture range.

(C) Purge gas usage range.

(D) Condensate (liquid fuel) separation range.

(E) Combustion zone temperature range. This is required for all devices that measure this parameter.

(F) Excess air range.

(G) Flame arrestor(s).

(H) Burner manifold.

(I) Pilot flame indicator.

(J) Pilot flame design fuel and calculated or measured fuel usage.

(K) Tip velocity range.

(L) Momentum flux ratio.

(M) Exit temperature range.

(N) Exit flow rate.

(O) Wind velocity and direction.

(vi) The test report must include all calibration quality assurance/quality control data, calibration gas values, gas cylinder certification, strip charts, or other graphic presentations of the data annotated with test times and calibration values.

(e) *Continuous compliance for combustion control devices tested by the manufacturer in accordance with paragraph (d) of this section.* This paragraph applies to the demonstration of compliance for a combustion control device tested under the provisions in paragraph (d) of this section. Owners or operators must demonstrate that a control device achieves the performance criteria in paragraph (d)(11) of this section by installing a device tested under paragraph (d) of this section, complying with the criteria specified in paragraphs (e)(1) through (7) of this section, maintaining the records specified in 60.5420a(b) and submitting the reports specified in 60.5420a(c).

(1) The inlet gas flow rate must be equal to or less than the maximum specified by the manufacturer.

(2) A pilot flame must be present at all times of operation.

(3) Devices must be operated with no visible emissions, except for periods not to exceed a total of 1 minute during any 15-minute period. A visible emissions test conducted according to section 11 of EPA Method 22 of appendix A–7 of this part must be performed at least once every calendar month, separated by at least 15 days between each test. The observation period shall be 15 minutes.

(4) Devices failing the visible emissions test must follow manufacturer's repair instructions, if available, or best combustion engineering practice as outlined in the unit inspection and maintenance plan, to return the unit to compliant operation. All repairs and maintenance activities for each unit must be recorded in a maintenance and repair log and must be available for inspection.

(5) Following return to operation from maintenance or repair activity, each device must pass a visual observation according to EPA Method 22 of appendix A–7 of this part as described in paragraph (e)(3) of this section.

(6) If the owner or operator operates a combustion control device model tested under this section, an electronic copy of the performance test results required by this section shall be submitted via email to *Oil_and_Gas_PT@EPA.GOV* unless the test results for that model of combustion control device are posted at the following Web site: *epa.gov/airquality/oilandgas/.*

(7) Ensure that each enclosed combustion control device is maintained in a leak free condition.

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

(a) For each well affected facility, you must demonstrate continuous compliance by submitting the reports required by § 60.5420a(b) and maintaining the records for each completion operation specified in § 60.5420a(c)(1).

(b) For each centrifugal compressor affected facility and each pneumatic pump affected facility at a location with a control device on site, you must demonstrate continuous compliance according to paragraphs (b)(1) through (3) of this section.

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

(2) For each control device used to reduce emissions, you must demonstrate continuous compliance with the performance requirements of § 60.5412a(a) using the procedures specified in paragraphs (b)(2)(i) through (vii) of this section. If you use a condenser as the control device to achieve the requirements specified in § 60.5412a(a)(2), you must demonstrate compliance according to paragraph (b)(2)(viii) of this section. You may switch between compliance with paragraphs (b)(2)(i) through (vii) of this section and compliance with paragraph (b)(2)(viii) of this section only after at least 1 year of operation in compliance with the selected approach. You must provide notification of such a change in the compliance method in the next annual report, as required in § 60.5420a(b), following the change.

(i) You must operate below (or above) the site specific maximum (or minimum) parameter value established according to the requirements of § 60.5417a(f)(1).

(ii) You must calculate the daily average of the applicable monitored parameter in accordance with § 60.5417a(e) except that the inlet gas flow rate to the control device must not be averaged.

(iii) Compliance with the operating parameter limit is achieved when the daily average of the monitoring parameter value calculated under paragraph (b)(2)(ii) of this section is either equal to or greater than the minimum monitoring value or equal to or less than the maximum monitoring value established under paragraph (b)(2)(i) of this section. When performance testing of a combustion control device is conducted by the device manufacturer as specified in § 60.5413a(d), compliance with the operating parameter limit is achieved when the criteria in § 60.5413a(e) are met.

(iv) You must operate the continuous monitoring system required in § 60.5417a at all times the affected source is operating, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities (including, as applicable, system accuracy audits and required zero and span adjustments). A monitoring system malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring system failures that are caused in part by poor maintenance or careless operation are not malfunctions. You are required to complete monitoring system repairs in response to monitoring system malfunctions and to return the monitoring system to operation as expeditiously as practicable.

(v) You may not use data recorded during monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or control activities in calculations used to report emissions or operating levels. You must use all the data collected during all other required data collection periods to assess the operation of the control device and associated control system.

(vi) Failure to collect required data is a deviation of the monitoring requirements, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required quality monitoring system quality assurance or quality control activities (including, as applicable, system accuracy audits and required zero and span adjustments).

(vii) If you use a combustion control device to meet the requirements of § 60.5412a(a) and you demonstrate compliance using the test procedures specified in § 60.5413a(b), you must comply with paragraphs (b)(2)(vii)(A) through (D) of this section.

(A) A pilot flame must be present at all times of operation.

(B) Devices must be operated with no visible emissions, except for periods not to exceed a total of 1 minute during any 15-minute period. A visible emissions test conducted according to section 11 of EPA Method 22, 40 CFR part 60, appendix A, must be performed at least once every calendar month, separated by at least 15 days between each test. The observation period shall be 15 minutes.

(C) Devices failing the visible emissions test must follow manufacturer's repair instructions, if available, or best combustion engineering practice as outlined in the unit inspection and maintenance plan, to return the unit to compliant operation. All repairs and maintenance activities for each unit must be recorded in a maintenance and repair log and must be available for inspection.

(D) Following return to operation from maintenance or repair activity, each device must pass a Method 22 of appendix A–7 of this part visual observation as described in paragraph (b)(2)(vii)(B) of this section.

(viii) If you use a condenser as the control device to achieve the percent reduction performance requirements specified in § 60.5412a(a)(2), you must demonstrate compliance using the procedures in paragraphs (b)(2)(viii)(A) through (E) of this section.

(A) You must establish a site-specific condenser performance curve according to § 60.5417a(f)(2).

(B) You must calculate the daily average condenser outlet temperature in accordance with § 60.5417a(e).

(C) You must determine the condenser efficiency for the current operating day using the daily average condenser outlet temperature calculated under paragraph (b)(2)(viii)(B) of this section and the condenser performance curve established under paragraph (b)(2)(viii)(A) of this section.

(D) Except as provided in paragraphs (b)(2)(viii)(D)(*1*) and (*2*) of this section, at the end of each operating day, you must calculate the 365-day rolling average TOC emission reduction, as appropriate, from the condenser efficiencies as determined in paragraph (b)(2)(viii)(C) of this section.

(*1*) After the compliance dates specified in § 60.5370a, if you have less than 120 days of data for determining average TOC emission reduction, you must calculate the average TOC emission reduction for the first 120 days of operation after the compliance date. You have demonstrated compliance with the overall 95.0 percent reduction requirement if the 120-day average TOC emission reduction is equal to or greater than 95.0 percent.

(*2*) After 120 days and no more than 364 days of operation after the compliance date specified in § 60.5370a, you must calculate the average TOC emission reduction as the TOC emission reduction averaged over the number of days between the current day and the applicable compliance date. You have demonstrated compliance with the overall 95.0 percent reduction requirement if the average TOC emission reduction is equal to or greater than 95.0 percent.

(E) If you have data for 365 days or more of operation, you have demonstrated compliance with the TOC emission reduction if the rolling 365-day average TOC emission reduction calculated in paragraph (b)(2)(viii)(D) of this section is equal to or greater than 95.0 percent.

(3) You must submit the annual report required by 60.5420a(b) and maintain the records as specified in

§ 60.5420a(c)(2), (6) through (11), and (16), as applicable.

(c) For each reciprocating compressor affected facility complying with § 60.5385a(a)(1) or (2), you must demonstrate continuous compliance according to paragraphs (c)(1) through (3) of this section. For each reciprocating compressor affected facility complying with § 60.5385a(a)(3), you must demonstrate continuous compliance according to paragraph (c)(4) of this section.

(1) You must continuously monitor the number of hours of operation for each reciprocating compressor affected facility or track the number of months since initial startup, or [date 60 days after publication of final rule in **Federal Register**], or the date of the most recent reciprocating compressor rod packing replacement, whichever is later.

(2) You must submit the annual report as required in § 60.5420a(b) and maintain records as required in § 60.5420a(c)(3).

(3) You must replace the reciprocating compressor rod packing before the total number of hours of operation reaches 26,000 hours or the number of months since the most recent rod packing replacement reaches 36 months.

(4) You must operate the rod packing emissions collection system under negative pressure and continuously comply with the closed vent requirements in § 60.5411a(a).

(d) For each pneumatic controller affected facility, you must demonstrate continuous compliance according to paragraphs (d)(1) through (3) of this section.

(1) You must continuously operate the pneumatic controllers as required in § 60.5390a(a), (b), or (c).

(2) You must submit the annual report as required in § 60.5420a(b).

(3) You must maintain records as required in § 60.5420a(c)(4).

(e) You must demonstrate continuous compliance according to paragraph (e)(3) of this section for each storage vessel affected facility, for which you are using a control device or routing emissions to a process to meet the requirement of § 60.5395a(a)(2).

(1)–(2) [Reserved]

(3) For each storage vessel affected facility, you must comply with paragraphs (e)(3)(i) and (ii) of this section.

(i) You must reduce methane and VOC emissions as specified in § 60.5395a(a).

(ii) For each control device installed to meet the requirements of § 60.5395a(a), you must demonstrate continuous compliance with the performance requirements of § 60.5412a(d) for each storage vessel affected facility using the procedure specified in paragraph (e)(3)(ii)(A) and either (e)(3)(ii)(B) or (e)(3)(ii)(C) of this section.

(A) You must comply with § 60.5416a(c) for each cover and closed vent system.

(B) You must comply with § 60.5417a(h) for each control device.

(C) Each closed vent system that routes emissions to a process must be operated as specified in § 60.5411a(c)(2).

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

(g) For each sweetening unit affected facility at onshore natural gas processing plants, you must demonstrate continuous compliance with the standards for SO_2 specified in § 60.5405a(b) according to paragraphs (g)(1) and (2) of this section.

(1) The minimum required SO_2 emission reduction efficiency (Z_c) is compared to the emission reduction efficiency (R) achieved by the sulfur recovery technology.

(i) If $R \geq Z_c$, your affected facility is in compliance.

(ii) If $R < Z_c$, your affected facility is not in compliance.

(2) The emission reduction efficiency (R) achieved by the sulfur reduction technology must be determined using the procedures in § 60.5406a(c)(1).

(h) For each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a compressor station, you must demonstrate continuous compliance with the fugitive emission standards specified in § 60.5397a according to paragraphs (h)(1) through (4) of this section.

(1) You must conduct periodic monitoring surveys as required in § 60.5397a(f) through (i).

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

(3) You must maintain records as specified in § 60.5420a(c)(15).

(4) You must submit annual reports for collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a compressor station as required in § 60.5420a(b).

§ 60.5416a What are the initial and continuous cover and closed vent system inspection and monitoring requirements for my centrifugal compressor, reciprocating compressor, pneumatic pump and storage vessel affected facilities?

For each closed vent system or cover at your storage vessel, centrifugal compressor, reciprocating compressor and pneumatic pump affected facilities, you must comply with the applicable requirements of paragraphs (a) through (c) of this section.

(a) *Inspections for closed vent systems and covers installed on each centrifugal compressor, reciprocating compressor or pneumatic pump affected facility.* Except as provided in paragraphs (b)(11) and (12) of this section, you must inspect each closed vent system according to the procedures and schedule specified in paragraphs (a)(1) and (2) of this section, inspect each cover according to the procedures and schedule specified in paragraph (a)(3) of this section, and inspect each bypass device according to the procedures of paragraph (a)(4) of this section.

(1) For each closed vent system joint, seam, or other connection that is permanently or semi-permanently sealed (*e.g.,* a welded joint between two sections of hard piping or a bolted and gasketed ducting flange), you must meet the requirements specified in paragraphs (a)(1)(i) and (ii) of this section.

(i) Conduct an initial inspection according to the test methods and procedures specified in paragraph (b) of this section to demonstrate that the closed vent system operates with no detectable emissions. You must maintain records of the inspection results as specified in § 60.5420a(c)(6).

(ii) Conduct annual visual inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in piping; loose connections; liquid leaks; or broken or missing caps or other closure devices. You must monitor a component or connection using the test methods and procedures in paragraph (b) of this section to demonstrate that it operates with no detectable emissions following any time the component is repaired or replaced or the connection is unsealed. You must maintain records of the inspection results as specified in § 60.5420a(c)(6).

(2) For closed vent system components other than those specified in paragraph (a)(1) of this section, you must meet the requirements of paragraphs (a)(2)(i) through (iii) of this section.

(i) Conduct an initial inspection according to the test methods and procedures specified in paragraph (b) of this section to demonstrate that the closed vent system operates with no detectable emissions. You must maintain records of the inspection results as specified in § 60.5420a(c)(6).

(ii) Conduct annual inspections according to the test methods and procedures specified in paragraph (b) of this section to demonstrate that the components or connections operate with no detectable emissions. You must maintain records of the inspection results as specified in § 60.5420a(c)(6).

(iii) Conduct annual visual inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in ductwork; loose connections; liquid leaks; or broken or missing caps or other closure devices. You must maintain records of the inspection results as specified in § 60.5420a(c)(6).

(3) For each cover, you must meet the requirements in paragraphs (a)(3)(i) and (ii) of this section.

(i) Conduct visual inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in the cover, or between the cover and the separator wall; broken, cracked, or otherwise damaged seals or gaskets on closure devices; and broken or missing hatches, access covers, caps, or other closure devices. In the case where the storage vessel is buried partially or entirely underground, you must inspect only those portions of the cover that extend to or above the ground surface, and those connections that are on such portions of the cover (e.g., fill ports, access hatches, gauge wells, etc.) and can be opened to the atmosphere.

(ii) You must initially conduct the inspections specified in paragraph (a)(3)(i) of this section following the installation of the cover. Thereafter, you must perform the inspection at least once every calendar year, except as provided in paragraphs (b)(11) and (12) of this section. You must maintain records of the inspection results as specified in § 60.5420a(c)(7).

(4) For each bypass device, except as provided for in § 60.5411a, you must meet the requirements of paragraphs (a)(4)(i) or (ii) of this section.

(i) Set the flow indicator to take a reading at least once every 15 minutes at the inlet to the bypass device that could divert the steam away from the control device to the atmosphere.

(ii) If the bypass device valve installed at the inlet to the bypass device is secured in the non-diverting position using a car-seal or a lock-and-key type configuration, visually inspect the seal or closure mechanism at least once every month to verify that the valve is maintained in the non-diverting position and the vent stream is not diverted through the bypass device. You must maintain records of the inspections according to § 60.5420a(c)(8).

(b) *No detectable emissions test methods and procedures.* If you are required to conduct an inspection of a closed vent system or cover at your centrifugal compressor, reciprocating compressor, or pneumatic pump affected facility as specified in paragraphs (a)(1), (2), or (3) of this section, you must meet the requirements of paragraphs (b)(1) through (13) of this section.

(1) You must conduct the no detectable emissions test procedure in accordance with Method 21 of appendix A–7 of this part.

(2) The detection instrument must meet the performance criteria of Method 21 of appendix A–7 of this part, except that the instrument response factor criteria in section 8.1.1 of Method 21 must be for the average composition of the fluid and not for each individual organic compound in the stream.

(3) You must calibrate the detection instrument before use on each day of its use by the procedures specified in Method 21 of appendix A–7 of this part.

(4) Calibration gases must be as specified in paragraphs (b)(4)(i) and (ii) of this section.

(i) Zero air (less than 10 parts per million by volume hydrocarbon in air).

(ii) A mixture of methane in air at a concentration less than 10,000 parts per million by volume.

(5) You may choose to adjust or not adjust the detection instrument readings to account for the background organic concentration level. If you choose to adjust the instrument readings for the background level, you must determine the background level value according to the procedures in Method 21 of appendix A–7 of this part.

(6) Your detection instrument must meet the performance criteria specified in paragraphs (b)(6)(i) and (ii) of this section.

(i) Except as provided in paragraph (b)(6)(ii) of this section, the detection instrument must meet the performance criteria of Method 21 of appendix A–7 of this part, except the instrument response factor criteria in section 8.1.1 of Method 21 must be for the average composition of the process fluid, not each individual volatile organic compound in the stream. For process streams that contain nitrogen, air, or other inerts that are not organic hazardous air pollutants or volatile organic compounds, you must calculate the average stream response factor on an inert-free basis.

(ii) If no instrument is available that will meet the performance criteria specified in paragraph (b)(6)(i) of this section, you may adjust the instrument readings by multiplying by the average response factor of the process fluid, calculated on an inert-free basis, as described in paragraph (b)(6)(i) of this section.

(7) You must determine if a potential leak interface operates with no detectable emissions using the applicable procedure specified in paragraph (b)(7)(i) or (ii) of this section.

(i) If you choose not to adjust the detection instrument readings for the background organic concentration level, then you must directly compare the maximum organic concentration value measured by the detection instrument to the applicable value for the potential leak interface as specified in paragraph (b)(8) of this section.

(ii) If you choose to adjust the detection instrument readings for the background organic concentration level, you must compare the value of the arithmetic difference between the maximum organic concentration value measured by the instrument and the background organic concentration value as determined in paragraph (b)(5) of this section with the applicable value for the potential leak interface as specified in paragraph (b)(8) of this section.

(8) A potential leak interface is determined to operate with no detectable organic emissions if the organic concentration value determined in paragraph (b)(7) of this section is less than 500 parts per million by volume.

(9) *Repairs.* In the event that a leak or defect is detected, you must repair the leak or defect as soon as practicable according to the requirements of paragraphs (b)(9)(i) and (ii) of this section, except as provided in paragraph (b)(10) of this section.

(i) A first attempt at repair must be made no later than 5 calendar days after the leak is detected.

(ii) Repair must be completed no later than 15 calendar days after the leak is detected.

(10) *Delay of repair.* Delay of repair of a closed vent system or cover for which leaks or defects have been detected is allowed if the repair is technically infeasible without a shutdown, or if you determine that emissions resulting from immediate repair would be greater than the fugitive emissions likely to result from delay of repair. You must complete repair of such equipment by the end of the next shutdown.

(11) *Unsafe to inspect requirements.* You may designate any parts of the

closed vent system or cover as unsafe to inspect if the requirements in paragraphs (b)(11)(i) and (ii) of this section are met. Unsafe to inspect parts are exempt from the inspection requirements of paragraphs (a)(1) through (3) of this section.

(i) You determine that the equipment is unsafe to inspect because inspecting personnel would be exposed to an imminent or potential danger as a consequence of complying with paragraphs (a)(1), (2), or (3) of this section.

(ii) You have a written plan that requires inspection of the equipment as frequently as practicable during safe-to-inspect times.

(12) *Difficult to inspect requirements.* You may designate any parts of the closed vent system or cover as difficult to inspect, if the requirements in paragraphs (b)(12)(i) and (ii) of this section are met. Difficult to inspect parts are exempt from the inspection requirements of paragraphs (a)(1) through (3) of this section.

(i) You determine that the equipment cannot be inspected without elevating the inspecting personnel more than 2 meters above a support surface.

(ii) You have a written plan that requires inspection of the equipment at least once every 5 years.

(13) *Records.* Records shall be maintained as specified in this section and in § 60.5420a(c)(9).

(c) *Cover and closed vent system inspections for storage vessel affected facilities.* If you install a control device or route emissions to a process, you must inspect each closed vent system according to the procedures and schedule specified in paragraphs (c)(1) of this section, inspect each cover according to the procedures and schedule specified in paragraph (c)(2) of this section, and inspect each bypass device according to the procedures of paragraph (c)(3) of this section. You must also comply with the requirements of (c)(4) through (7) of this section.

(1) For each closed vent system, you must conduct an inspection at least once every calendar month as specified in paragraphs (c)(1)(i) through (iii) of this section.

(i) You must maintain records of the inspection results as specified in § 60.5420a(c)(6).

(ii) Conduct olfactory, visual and auditory inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in piping; loose connections; liquid leaks; or broken or missing caps or other closure devices.

(iii) Monthly inspections must be separated by at least 14 calendar days.

(2) For each cover, you must conduct inspections at least once every calendar month as specified in paragraphs (c)(2)(i) through (iii) of this section.

(i) You must maintain records of the inspection results as specified in § 60.5420a(c)(7).

(ii) Conduct olfactory, visual and auditory inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in the cover, or between the cover and the separator wall; broken, cracked, or otherwise damaged seals or gaskets on closure devices; and broken or missing hatches, access covers, caps, or other closure devices. In the case where the storage vessel is buried partially or entirely underground, you must inspect only those portions of the cover that extend to or above the ground surface, and those connections that are on such portions of the cover (*e.g.,* fill ports, access hatches, gauge wells, etc.) and can be opened to the atmosphere.

(iii) Monthly inspections must be separated by at least 14 calendar days.

(3) For each bypass device, except as provided for in § 60.5411a(c)(3)(ii), you must meet the requirements of paragraphs (c)(3)(i) or (ii) of this section.

(i) You must properly install, calibrate and maintain a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere. Set the flow indicator to trigger an audible and visible alarm, and initiate notification via remote alarm to the nearest field office, when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere. You must maintain records of each time the alarm is sounded according to § 60.5420a(c)(8).

(ii) If the bypass device valve installed at the inlet to the bypass device is secured in the non-diverting position using a car-seal or a lock-and-key type configuration, visually inspect the seal or closure mechanism at least once every month to verify that the valve is maintained in the non-diverting position and the vent stream is not diverted through the bypass device. You must maintain records of the inspections and records of each time the key is checked out, if applicable, according to § 60.5420a(c)(8).

(4) *Repairs.* In the event that a leak or defect is detected, you must repair the leak or defect as soon as practicable according to the requirements of paragraphs (c)(4)(i) through (iii) of this section, except as provided in paragraph (c)(5) of this section.

(i) A first attempt at repair must be made no later than 5 calendar days after the leak is detected.

(ii) Repair must be completed no later than 30 calendar days after the leak is detected.

(iii) Grease or another applicable substance must be applied to deteriorating or cracked gaskets to improve the seal while awaiting repair.

(5) *Delay of repair.* Delay of repair of a closed vent system or cover for which leaks or defects have been detected is allowed if the repair is technically infeasible without a shutdown, or if you determine that emissions resulting from immediate repair would be greater than the fugitive emissions likely to result from delay of repair. You must complete repair of such equipment by the end of the next shutdown.

(6) *Unsafe to inspect requirements.* You may designate any parts of the closed vent system or cover as unsafe to inspect if the requirements in paragraphs (c)(6)(i) and (ii) of this section are met. Unsafe to inspect parts are exempt from the inspection requirements of paragraphs (c)(1) and (2) of this section.

(i) You determine that the equipment is unsafe to inspect because inspecting personnel would be exposed to an imminent or potential danger as a consequence of complying with paragraphs (c)(1) or (2) of this section.

(ii) You have a written plan that requires inspection of the equipment as frequently as practicable during safe-to-inspect times.

(7) *Difficult to inspect requirements.* You may designate any parts of the closed vent system or cover as difficult to inspect, if the requirements in paragraphs (c)(7)(i) and (ii) of this section are met. Difficult to inspect parts are exempt from the inspection requirements of paragraphs (c)(1) and (2) of this section.

(i) You determine that the equipment cannot be inspected without elevating the inspecting personnel more than 2 meters above a support surface.

(ii) You have a written plan that requires inspection of the equipment at least once every 5 years.

§ 60.5417a What are the continuous control device monitoring requirements for my centrifugal compressor, pneumatic pump, and storage vessel affected facilities?

You must meet the applicable requirements of this section to demonstrate continuous compliance for each control device used to meet emission standards for your storage vessel, centrifugal compressor or pneumatic pump affected facility.

(a) For each control device used to comply with the emission reduction standard for centrifugal compressor affected facilities in § 60.5380a(a)(1) or the emission reduction standard for pneumatic pumps affected facilities in § 60.5393a(b)(1), you must install and operate a continuous parameter monitoring system for each control device as specified in paragraphs (c) through (g) of this section, except as provided for in paragraph (b) of this section. If you install and operate a flare in accordance with § 60.5412a(a)(3), you are exempt from the requirements of paragraphs (e) and (f) of this section.

(b) You are exempt from the monitoring requirements specified in paragraphs (c) through (g) of this section for the control devices listed in paragraphs (b)(1) and (2) of this section.

(1) A boiler or process heater in which all vent streams are introduced with the primary fuel or are used as the primary fuel.

(2) A boiler or process heater with a design heat input capacity equal to or greater than 44 megawatts.

(c) If you are required to install a continuous parameter monitoring system, you must meet the specifications and requirements in paragraphs (c)(1) through (4) of this section.

(1) Each continuous parameter monitoring system must measure data values at least once every hour and record the parameters in paragraphs (c)(1)(i) or (ii) of this section.

(i) Each measured data value.

(ii) Each block average value for each 1-hour period or shorter periods calculated from all measured data values during each period. If values are measured more frequently than once per minute, a single value for each minute may be used to calculate the hourly (or shorter period) block average instead of all measured values.

(2) You must prepare a site-specific monitoring plan that addresses the monitoring system design, data collection, and the quality assurance and quality control elements outlined in paragraphs (c)(2)(i) through (v) of this section. You must install, calibrate, operate, and maintain each continuous parameter monitoring system in accordance with the procedures in your approved site-specific monitoring plan.

(i) The performance criteria and design specifications for the monitoring system equipment, including the sample interface, detector signal analyzer, and data acquisition and calculations.

(ii) Sampling interface (*e.g.*, thermocouple) location such that the monitoring system will provide representative measurements.

(iii) Equipment performance checks, system accuracy audits, or other audit procedures.

(iv) Ongoing operation and maintenance procedures in accordance with provisions in § 60.13(b).

(v) Ongoing reporting and recordkeeping procedures in accordance with provisions in § 60.7(c), (d), and (f).

(3) You must conduct the continuous parameter monitoring system equipment performance checks, system accuracy audits, or other audit procedures specified in the site-specific monitoring plan at least once every 12 months.

(4) You must conduct a performance evaluation of each continuous parameter monitoring system in accordance with the site-specific monitoring plan.

(d) You must install, calibrate, operate, and maintain a device equipped with a continuous recorder to measure the values of operating parameters appropriate for the control device as specified in paragraph (d)(1), (2), or (3) of this section.

(1) A continuous monitoring system that measures the operating parameters in paragraphs (d)(1)(i) through (viii) of this section, as applicable.

(i) For a thermal vapor incinerator that demonstrates during the performance test conducted under § 60.5413a that combustion zone temperature is an accurate indicator of performance, a temperature monitoring device equipped with a continuous recorder. The monitoring device must have a minimum accuracy of ±1 percent of the temperature being monitored in °C, or ±2.5 °C, whichever value is greater. You must install the temperature sensor at a location representative of the combustion zone temperature.

(ii) For a catalytic vapor incinerator, a temperature monitoring device equipped with a continuous recorder. The device must be capable of monitoring temperature at two locations and have a minimum accuracy of ±1 percent of the temperature being monitored in °C, or ±2.5 °C, whichever value is greater. You must install one temperature sensor in the vent stream at the nearest feasible point to the catalyst bed inlet, and you must install a second temperature sensor in the vent stream at the nearest feasible point to the catalyst bed outlet.

(iii) For a flare, a heat sensing monitoring device equipped with a continuous recorder that indicates the continuous ignition of the pilot flame.

(iv) For a boiler or process heater, a temperature monitoring device equipped with a continuous recorder. The temperature monitoring device must have a minimum accuracy of ±1 percent of the temperature being monitored in °C, or ±2.5 °C, whichever value is greater. You must install the temperature sensor at a location representative of the combustion zone temperature.

(v) For a condenser, a temperature monitoring device equipped with a continuous recorder. The temperature monitoring device must have a minimum accuracy of ±1 percent of the temperature being monitored in °C, or ±2.5 °C, whichever value is greater. You must install the temperature sensor at a location in the exhaust vent stream from the condenser.

(vi) For a regenerative-type carbon adsorption system, a continuous monitoring system that meets the specifications in paragraphs (d)(1)(vi)(A) and (B) of this section.

(A) The continuous parameter monitoring system must measure and record the average total regeneration stream mass flow or volumetric flow during each carbon bed regeneration cycle. The flow sensor must have a measurement sensitivity of 5 percent of the flow rate or 10 cubic feet per minute, whichever is greater. You must check the mechanical connections for leakage at least every month, and you must perform a visual inspection at least every 3 months of all components of the flow continuous parameter monitoring system for physical and operational integrity and all electrical connections for oxidation and galvanic corrosion if your flow continuous parameter monitoring system is not equipped with a redundant flow sensor; and

(B) The continuous parameter monitoring system must measure and record the average carbon bed temperature for the duration of the carbon bed steaming cycle and measure the actual carbon bed temperature after regeneration and within 15 minutes of completing the cooling cycle. The temperature monitoring device must have a minimum accuracy of ±1 percent of the temperature being monitored in °C, or ±2.5 °C, whichever value is greater.

(vii) For a nonregenerative-type carbon adsorption system, you must monitor the design carbon replacement interval established using a design analysis performed as specified in § 60.5413a(c)(3). The design carbon replacement interval must be based on the total carbon working capacity of the control device and source operating schedule.

(viii) For a combustion control device whose model is tested under § 60.5413a(d), a continuous monitoring system meeting the requirements of paragraphs (d)(1)(viii)(A) and (B) of this section.

(A) The continuous monitoring system must measure gas flow rate at the inlet to the control device. The monitoring instrument must have an accuracy of ±2 percent or better. The flow rate at the inlet to the combustion device must not exceed the maximum or be less than the minimum flow rate determined by the manufacturer.

(B) A monitoring device that continuously indicates the presence of the pilot flame while emissions are routed to the control device.

(2) An organic monitoring device equipped with a continuous recorder that measures the concentration level of organic compounds in the exhaust vent stream from the control device. The monitor must meet the requirements of Performance Specification 8 or 9 of appendix B of this part. You must install, calibrate, and maintain the monitor according to the manufacturer's specifications.

(3) A continuous monitoring system that measures operating parameters other than those specified in paragraph (d)(1) or (2) of this section, upon approval of the Administrator as specified in § 60.13(i).

(e) You must calculate the daily average value for each monitored operating parameter for each operating day, using the data recorded by the monitoring system, except for inlet gas flow rate. If the emissions unit operation is continuous, the operating day is a 24-hour period. If the emissions unit operation is not continuous, the operating day is the total number of hours of control device operation per 24-hour period. Valid data points must be available for 75 percent of the operating hours in an operating day to compute the daily average.

(f) For each operating parameter monitor installed in accordance with the requirements of paragraph (d) of this section, you must comply with paragraph (f)(1) of this section for all control devices. When condensers are installed, you must also comply with paragraph (f)(2) of this section.

(1) You must establish a minimum operating parameter value or a maximum operating parameter value, as appropriate for the control device, to define the conditions at which the control device must be operated to continuously achieve the applicable performance requirements of § 60.5412a(a). You must establish each minimum or maximum operating parameter value as specified in paragraphs (f)(1)(i) through (iii) of this section.

(i) If you conduct performance tests in accordance with the requirements of § 60.5413a(b) to demonstrate that the control device achieves the applicable performance requirements specified in § 60.5412a(a), then you must establish the minimum operating parameter value or the maximum operating parameter value based on values measured during the performance test and supplemented, as necessary, by a condenser design analysis or control device manufacturer recommendations or a combination of both.

(ii) If you use a condenser design analysis in accordance with the requirements of § 60.5413a(c) to demonstrate that the control device achieves the applicable performance requirements specified in § 60.5412a(a), then you must establish the minimum operating parameter value or the maximum operating parameter value based on the condenser design analysis and supplemented, as necessary, by the condenser manufacturer's recommendations.

(iii) If you operate a control device where the performance test requirement was met under § 60.5413a(d) to demonstrate that the control device achieves the applicable performance requirements specified in § 60.5412a(a), then your control device inlet gas flow rate must not exceed the maximum or be less than the minimum inlet gas flow rate determined by the manufacturer.

(2) If you use a condenser as specified in paragraph (d)(1)(v) of this section, you must establish a condenser performance curve showing the relationship between condenser outlet temperature and condenser control efficiency, according to the requirements of paragraphs (f)(2)(i) and (ii) of this section.

(i) If you conduct a performance test in accordance with the requirements of § 60.5413a(b) to demonstrate that the condenser achieves the applicable performance requirements in § 60.5412a(a), then the condenser performance curve must be based on values measured during the performance test and supplemented as necessary by control device design analysis, or control device manufacturer's recommendations, or a combination or both.

(ii) If you use a control device design analysis in accordance with the requirements of § 60.5413a(c)(1) to demonstrate that the condenser achieves the applicable performance requirements specified in § 60.5412a(a), then the condenser performance curve must be based on the condenser design analysis and supplemented, as necessary, by the control device manufacturer's recommendations.

(g) A deviation for a given control device is determined to have occurred when the monitoring data or lack of monitoring data result in any one of the criteria specified in paragraphs (g)(1) through (g)(6) of this section being met. If you monitor multiple operating parameters for the same control device during the same operating day and more than one of these operating parameters meets a deviation criterion specified in paragraphs (g)(1) through (6) of this section, then a single excursion is determined to have occurred for the control device for that operating day.

(1) A deviation occurs when the daily average value of a monitored operating parameter is less than the minimum operating parameter limit (or, if applicable, greater than the maximum operating parameter limit) established in paragraph (f)(1) of this section.

(2) If you are subject to § 60.5412a(a)(2), a deviation occurs when the 365-day average condenser efficiency calculated according to the requirements specified in § 60.5415a(b)(2)(viii)(D) is less than 95.0 percent.

(3) If you are subject to § 60.5412a(a)(2) and you have less than 365 days of data, a deviation occurs when the average condenser efficiency calculated according to the procedures specified in § 60.5415a(b)(2)(viii)(D)(*1*) or (*2*) is less than 95.0 percent.

(4) A deviation occurs when the monitoring data are not available for at least 75 percent of the operating hours in a day.

(5) If the closed vent system contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the control device, a deviation occurs when the requirements of paragraph (g)(5)(i) or (ii) of this section are met.

(i) For each bypass line subject to § 60.5411a(a)(3)(i)(A), the flow indicator indicates that flow has been detected and that the stream has been diverted away from the control device to the atmosphere.

(ii) For each bypass line subject to § 60.5411a(a)(3)(i)(B), if the seal or closure mechanism has been broken, the bypass line valve position has changed, the key for the lock-and-key type lock has been checked out, or the car-seal has broken.

(6) For a combustion control device whose model is tested under § 60.5413a(d), a deviation occurs when the conditions of paragraphs (g)(6)(i) or (ii) are met.

(i) The inlet gas flow rate exceeds the maximum established during the test conducted under § 60.5413a(d).

(ii) Failure of the monthly visible emissions test conducted under § 60.5413a(e)(3) occurs.

(h) For each control device used to comply with the emission reduction standard in § 60.5395a(a)(2) for your storage vessel affected facility, you must demonstrate continuous compliance according to paragraphs (h)(1) through (h)(4) of this section. You are exempt from the requirements of this paragraph if you install a control device model tested in accordance with § 60.5413a(d)(2) through (10), which meets the criteria in § 60.5413a(d)(11), the reporting requirement in § 60.5413a(d)(12), and meet the continuous compliance requirement in § 60.5413a(e).

(1) For each combustion device you must conduct inspections at least once every calendar month according to paragraphs (h)(1)(i) through (iv) of this section. Monthly inspections must be separated by at least 14 calendar days.

(i) Conduct visual inspections to confirm that the pilot is lit when vapors are being routed to the combustion device and that the continuous burning pilot flame is operating properly.

(ii) Conduct inspections to monitor for visible emissions from the combustion device using section 11 of EPA Method 22 of appendix A of this part. The observation period shall be 15 minutes. Devices must be operated with no visible emissions, except for periods not to exceed a total of 1 minute during any 15 minute period.

(iii) Conduct olfactory, visual and auditory inspections of all equipment associated with the combustion device to ensure system integrity.

(iv) For any absence of the pilot flame, or other indication of smoking or improper equipment operation (*e.g.,* visual, audible, or olfactory), you must ensure the equipment is returned to proper operation as soon as practicable after the event occurs. At a minimum, you must perform the procedures specified in paragraphs (h)(1)(iv)(A) and (B) of this section.

(A) You must check the air vent for obstruction. If an obstruction is observed, you must clear the obstruction as soon as practicable.

(B) You must check for liquid reaching the combustor.

(2) For each vapor recovery device, you must conduct inspections at least once every calendar month to ensure physical integrity of the control device according to the manufacturer's instructions. Monthly inspections must be separated by at least 14 calendar days.

(3) Each control device must be operated following the manufacturer's written operating instructions, procedures and maintenance schedule to ensure good air pollution control practices for minimizing emissions. Records of the manufacturer's written operating instructions, procedures, and maintenance schedule must be available for inspection as specified in § 60.5420a(c)(13).

(4) Conduct a periodic performance test no later than 60 months after the initial performance test as specified in § 60.5413a(b)(5)(ii) and conduct subsequent periodic performance tests at intervals no longer than 60 months following the previous periodic performance test.

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

(a) You must submit the notifications according to paragraphs (a)(1) and (2) of this section if you own or operate one or more of the affected facilities specified in § 60.5365a that was constructed, modified, or reconstructed during the reporting period.

(1) If you own or operate a well, centrifugal compressor, reciprocating compressor, pneumatic controller, pneumatic pump, storage vessel, or collection of fugitive emissions components at a well site or collection of fugitive emissions components at a compressor station you are not required to submit the notifications required in § 60.7(a)(1), (3), and (4).

(2)(i) If you own or operate a well affected facility, you must submit a notification to the Administrator no later than 2 days prior to the commencement of each well completion operation listing the anticipated date of the well completion operation. The notification shall include contact information for the owner or operator; the API well number; the latitude and longitude coordinates for each well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983; and the planned date of the beginning of flowback. You may submit the notification in writing or in electronic format.

(ii) If you are subject to state regulations that require advance notification of well completions and you have met those notification requirements, then you are considered to have met the advance notification requirements of paragraph (a)(2)(i) of this section.

(b) *Reporting requirements.* You must submit annual reports containing the information specified in paragraphs (b)(1) through (8) of this section and performance test reports as specified in paragraph (b)(9) or (10) of this section. You must submit annual reports following the procedure specified in paragraph (b)(11). The initial annual report is due no later than 90 days after the end of the initial compliance period as determined according to § 60.5410a. Subsequent annual reports are due no later than same date each year as the initial annual report. If you own or operate more than one affected facility, you may submit one report for multiple affected facilities provided the report contains all of the information required as specified in paragraphs (b)(1) through (10) of this section. Annual reports may coincide with title V reports as long as all the required elements of the annual report are included. You may arrange with the Administrator a common schedule on which reports required by this part may be submitted as long as the schedule does not extend the reporting period.

(1) The general information specified in paragraphs (b)(1)(i) through (iv) of this section for all reports.

(i) The company name and address of the affected facility.

(ii) An identification of each affected facility being included in the annual report.

(iii) Beginning and ending dates of the reporting period.

(iv) A certification by a certifying official of truth, accuracy, and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

(2) For each well affected facility, the information in paragraphs (b)(2)(i) and (ii) of this section.

(i) Records of each well completion operation as specified in paragraph (c)(1)(i) through (iv) of this section for each well affected facility conducted during the reporting period. In lieu of submitting the records specified in paragraph (c)(1)(i) through (iv), the owner or operator may submit a list of the well completions with hydraulic fracturing completed during the reporting period and the records required by paragraph (c)(1)(v) of this section for each well completion.

(ii) Records of deviations specified in paragraph (c)(1)(ii) of this section that occurred during the reporting period.

(3) For each centrifugal compressor affected facility, the information

specified in paragraphs (b)(3)(i) through (iv) of this section.

(i) An identification of each centrifugal compressor using a wet seal system constructed, modified or reconstructed during the reporting period.

(ii) Records of deviations specified in paragraph (c)(2) of this section that occurred during the reporting period.

(iii) If required to comply with § 60.5380a(a)(2), the records specified in paragraphs (c)(6) through (11) of this section.

(iv) If complying with § 60.5380a(a)(1) with a control device tested under § 60.5413a(d) which meets the criteria in § 60.5413a(d)(11) and § 60.5413a(e), records specified in paragraph (c)(2)(i) through (c)(2)(vii) of this section for each centrifugal compressor using a wet seal system constructed, modified or reconstructed during the reporting period.

(4) For each reciprocating compressor affected facility, the information specified in paragraphs (b)(4)(i) and (ii) of this section.

(i) The cumulative number of hours of operation or the number of months since initial startup, since [date 60 days after publication of final rule in the **Federal Register**], or since the previous reciprocating compressor rod packing replacement, whichever is later.

(ii) Records of deviations specified in paragraph (c)(3)(iii) of this section that occurred during the reporting period.

(5) For each pneumatic controller affected facility, the information specified in paragraphs (b)(5)(i) through (iii) of this section.

(i) An identification of each pneumatic controller constructed, modified or reconstructed during the reporting period, including the identification information specified in § 60.5390a(b)(2) or (c)(2).

(ii) If applicable, documentation that the use of pneumatic controller affected facilities with a natural gas bleed rate greater than 6 standard cubic feet per hour are required and the reasons why.

(iii) Records of deviations specified in paragraph (c)(4)(v) of this section that occurred during the reporting period.

(6) For each storage vessel affected facility, the information in paragraphs (b)(6)(i) through (vii) of this section.

(i) An identification, including the location, of each storage vessel affected facility for which construction, modification or reconstruction commenced during the reporting period. The location of the storage vessel shall be in latitude and longitude coordinates in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

(ii) Documentation of the VOC emission rate determination according to § 60.5365a(e) for each storage vessel that became an affected facility during the reporting period or is returned to service during the reporting period.

(iii) Records of deviations specified in paragraph (c)(5)(iii) of this section that occurred during the reporting period.

(iv) A statement that you have met the requirements specified in § 60.5410a(h)(2) and (3).

(v) You must identify each storage vessel affected facility that is removed from service during the reporting period as specified in § 60.5395a(c)(1)(ii), including the date the storage vessel affected facility was removed from service.

(vi) You must identify each storage vessel affected facility returned to service during the reporting period as specified in § 60.5395a(c)(3), including the date the storage vessel affected facility was returned to service.

(vii) If complying with § 60.5395a(a)(2) with a control device tested under § 60.5413a(d) which meets the criteria in § 60.5413a(d)(11) and § 60.5413a(e), records specified in paragraphs (c)(5)(vi)(A) through (G) of this section for each storage vessel constructed, modified, reconstructed or returned to service during the reporting period.

(7) For the collection of fugitive emissions components at a well site and the collection of fugitive emissions components at a compressor station, the records of each monitoring survey conducted during the year:

(i) Date of the survey.

(ii) Beginning and end time of the survey.

(iii) Name of operator(s) performing survey. If the survey is performed by optical gas imaging, you must note the training and experience of the operator.

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

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

(vi) Documentation of each fugitive emission, including the information specified in paragraphs (b)(7)(vi)(A) through (C) of this section

(A) Location.

(B) One or more digital photographs of each required monitoring survey being performed. The digital photograph must include the date the photograph was taken and the latitude and longitude of the collection of fugitive emissions components at a well site or collection of fugitive emissions components at a compressor station imbedded within or stored with the digital file. As an alternative to imbedded latitude and longitude within the digital photograph, the digital photograph may consist of a photograph of the monitoring survey being performed with a photograph of a separately operating GIS device within the same digital picture, provided the latitude and longitude output of the GIS unit can be clearly read in the digital photograph.

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

(D) Type of instrument used to resurvey a repaired fugitive emissions component that could not be repaired during the initial fugitive emissions finding.

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

(i) In the initial annual report, a certification that there is no control device on site, if applicable.

(ii) An identification of each pneumatic pump constructed, modified or reconstructed during the reporting period, including the identification information specified in § 60.5393a(a)(2) or (b)(2).

(iii) An identification of any sites which contain natural pneumatic pumps and which installed a control device during the reporting period, where there was no control device previously at the site.

(iv) Records of deviations specified in paragraph (c)(16)(ii) of this section that occurred during the reporting period.

(v) If complying with § 60.5393a(b)(1) with a control device tested under § 60.5413(d), which meets the criteria in § 60.5413(d)(11) and § 60.5413(e), records specified in paragraphs (c)(16)(iv)(A) through (G) of this section for each pneumatic pump constructed, modified or reconstructed during the reporting period.

(9) Within 60 days after the date of completing each performance test (see § 60.8) required by this subpart, except testing conducted by the manufacturer as specified in § 60.5413a(d), you must submit the results of the performance test following the procedure specified in either paragraph (b)(9)(i) or (ii) of this section.

(i) For data collected using test methods supported by the EPA's Electronic Reporting Tool (ERT) as listed on the EPA's ERT Web site (*http://www.epa.gov/ttn/chief/ert/index.html*) at the time of the test, you must submit the results of the performance test to the EPA via the

Compliance and Emissions Data Reporting Interface (CEDRI). (CEDRI can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*).) Performance test data must be submitted in a file format generated through the use of the EPA's ERT or an alternate electronic file format consistent with the extensible markup language (XML) schema listed on the EPA's ERT Web site. If you claim that some of the performance test information being submitted is confidential business information (CBI), you must submit a complete file generated through the use of the EPA's ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT Web site, including information claimed to be CBI, on a compact disc, flash drive, or other commonly used electronic storage media to the EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAQPS/CORE CBI Office, Attention: Group Leader, Measurement Policy Group, MD C404–02, 4930 Old Page Rd., Durham, NC 27703. The same ERT or alternate file with the CBI omitted must be submitted to the EPA via the EPA's CDX as described earlier in this paragraph.

(ii) For data collected using test methods that are not supported by the EPA's ERT as listed on the EPA's ERT Web site at the time of the test, you must submit the results of the performance test to the Administrator at the appropriate address listed in § 60.4.

(10) For combustion control devices tested by the manufacturer in accordance with § 60.5413a(d), an electronic copy of the performance test results required by § 60.5413a(d) shall be submitted via email to *Oil_and_Gas_PT@EPA.GOV* unless the test results for that model of combustion control device are posted at the following Web site: *epa.gov/airquality/oilandgas/*.

(11) You must submit reports to the EPA via the CEDRI. (CEDRI can be accessed through the EPA's CDX (*https://cdx.epa.gov/*).) You must use the appropriate electronic report in CEDRI for this subpart or an alternate electronic file format consistent with the extensible markup language (XML) schema listed on the CEDRI Web site (*http://www.epa.gov/ttn/chief/cedri/index.html*). If the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, you must submit the report to the Administrator at the appropriate address listed in § 60.4. You must begin submitting reports via CEDRI no later than 90 days after the form becomes available in CEDRI. The reports must be submitted by the deadlines specified in this subpart, regardless of the method in which the reports are submitted.

(c) *Recordkeeping requirements.* You must maintain the records identified as specified in § 60.7(f) and in paragraphs (c)(1) through (16) of this section. All records required by this subpart must be maintained either onsite or at the nearest local field office for at least 5 years. Any records required to be maintained by this subpart that are submitted electronically via the EPA's CDX may be maintained in electronic format.

(1) The records for each well affected facility as specified in paragraphs (c)(1)(i) through (v) of this section.

(i) Records identifying each well completion operation for each well affected facility;

(ii) Records of deviations in cases where well completion operations with hydraulic fracturing were not performed in compliance with the requirements specified in § 60.5375a.

(iii) Records required in § 60.5375a(b) or (f) for each well completion operation conducted for each well affected facility that occurred during the reporting period. You must maintain the records specified in paragraphs (c)(1)(iii)(A) and (B) of this section.

(A) For each well affected facility required to comply with the requirements of § 60.5375a(a), you must record: The location of the well; the API well number; the date and time of the onset of flowback following hydraulic fracturing or refracturing; the date and time of each attempt to direct flowback to a separator as required in § 60.5375a(a)(1)(ii); the date and time of each occurrence of returning to the initial flowback stage under § 60.5375a(a)(1)(i); and the date and time that the well was shut in and the flowback equipment was permanently disconnected, or the startup of production; the duration of flowback; duration of recovery to the flow line; duration of combustion; duration of venting; and specific reasons for venting in lieu of capture or combustion. The duration must be specified in hours.

(B) For each well affected facility required to comply with the requirements of § 60.5375a(f), you must maintain the records specified in paragraph (c)(1)(iii)(A) of this section except that you do not have to record the duration of recovery to the flow line.

(iv) For each well affected facility for which you claim an exception under § 60.5375a(a)(3), you must record: The location of the well; the API well number; the specific exception claimed; the starting date and ending date for the period the well operated under the exception; and an explanation of why the well meets the claimed exception.

(v) For each well affected facility required to comply with both § 60.5375a(a)(1) and (3), if you are using a digital photograph in lieu of the records required in paragraphs (c)(1)(i) through (iv) of this section, you must retain the records of the digital photograph as specified in § 60.5410a(a)(4).

(2) For each centrifugal compressor affected facility, you must maintain records of deviations in cases where the centrifugal compressor was not operated in compliance with the requirements specified in § 60.5380a. Except as specified in paragraph (c)(2)(vii) of this section, you must maintain the records in paragraphs (c)(2)(i) through (vi) of this section for each control device tested under § 60.5413a(d) which meets the criteria in § 60.5413a(d)(11) and § 60.5413a(e) and used to comply with § 60.5380a(a)(1) for each centrifugal compressor.

(i) Make, model and serial number of purchased device.

(ii) Date of purchase.

(iii) Copy of purchase order.

(iv) Location of the centrifugal compressor and control device in latitude and longitude coordinates in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

(v) Inlet gas flow rate.

(vi) Records of continuous compliance requirements in § 60.5413a(e) as specified in paragraphs (c)(2)(vi)(A) through (D) of this section.

(A) Records that the pilot flame is present at all times of operation.

(B) Records that the device was operated with no visible emissions except for periods not to exceed a total of 2 minutes during any hour.

(C) Records of the maintenance and repair log.

(D) Records of the visible emissions test following return to operation from a maintenance or repair activity.

(vii) As an alternative to the requirements of paragraph (c)(2)(iv) of this section, you may maintain records of one or more digital photographs with the date the photograph was taken and the latitude and longitude of the centrifugal compressor and control device imbedded within or stored with the digital file. As an alternative to imbedded latitude and longitude within the digital photograph, the digital photograph may consist of a photograph of the centrifugal compressor and control device with a photograph of a separately operating GIS device within the same digital picture, provided the latitude and longitude output of the GIS unit can be clearly read in the digital photograph.

(3) For each reciprocating compressor affected facility, you must maintain the records in paragraphs (c)(3)(i) through (iii) of this section.

(i) Records of the cumulative number of hours of operation or number of months since initial startup or [date 60 days after publication of final rule in the **Federal Register**], or the previous replacement of the reciprocating compressor rod packing, whichever is later.

(ii) Records of the date and time of each reciprocating compressor rod packing replacement, or date of installation of a rod packing emissions collection system and closed vent system as specified in § 60.5385a(a)(3).

(iii) Records of deviations in cases where the reciprocating compressor was not operated in compliance with the requirements specified in § 60.5385a.

(4) For each pneumatic controller affected facility, you must maintain the records identified in paragraphs (c)(4)(i) through (v) of this section, as applicable.

(i) Records of the date, location and manufacturer specifications for each pneumatic controller constructed, modified or reconstructed.

(ii) Records of the demonstration that the use of pneumatic controller affected facilities with a natural gas bleed rate greater than the applicable standard are required and the reasons why.

(iii) If the pneumatic controller is not located at a natural gas processing plant, records of the manufacturer's specifications indicating that the controller is designed such that natural gas bleed rate is less than or equal to 6 standard cubic feet per hour.

(iv) If the pneumatic controller is located at a natural gas processing plant, records of the documentation that the natural gas bleed rate is zero.

(v) Records of deviations in cases where the pneumatic controller was not operated in compliance with the requirements specified in § 60.5390a.

(5) For each storage vessel affected facility, you must maintain the records identified in paragraphs (c)(5)(i) through (vi) of this section.

(i) If required to reduce emissions by complying with § 60.5395a(a)(2), the records specified in §§ 60.5420a(c)(6) through (8), 60.5416a(c)(6)(ii), and 60.5416a(c)(7)(ii). You must maintain the records in paragraph (c)(5)(vi) of this part for each control device tested under § 60.5413a(d) which meets the criteria in § 60.5413a(d)(11) and § 60.5413a(e) and used to comply with § 60.5395a(a)(2) for each storage vessel.

(ii) Records of each VOC emissions determination for each storage vessel affected facility made under § 60.5365a(e) including identification of the model or calculation methodology used to calculate the VOC emission rate.

(iii) Records of deviations in cases where the storage vessel was not operated in compliance with the requirements specified in §§ 60.5395a, 60.5411a, 60.5412a, and 60.5413a, as applicable.

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

(v) You must maintain records of the identification and location of each storage vessel affected facility.

(vi) Except as specified in paragraph (c)(5)(vi)(G) of this section, you must maintain the records specified in paragraphs (c)(5)(vi)(A) through (F) of this section for each control device tested under § 60.5413a(d) which meets the criteria in § 60.5413a(d)(11) and § 60.5413a(e) and used to comply with § 60.5395a(a)(2) for each storage vessel.

(A) Make, model and serial number of purchased device.

(B) Date of purchase.

(C) Copy of purchase order.

(D) Location of the control device in latitude and longitude coordinates in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

(E) Inlet gas flow rate.

(F) Records of continuous compliance requirements in § 60.5413a(e) as specified in paragraphs (c)(5)(vi)(F)(*1*) through (*4*).

(*1*) Records that the pilot flame is present at all times of operation.

(*2*) Records that the device was operated with no visible emissions except for periods not to exceed a total of 2 minutes during any hour.

(*3*) Records of the maintenance and repair log.

(*4*) Records of the visible emissions test following return to operation from a maintenance or repair activity.

(G) As an alternative to the requirements of paragraph (c)(5)(vi)(D) of this section, you may maintain records of one or more digital photographs with the date the photograph was taken and the latitude and longitude of the storage vessel and control device imbedded within or stored with the digital file. As an alternative to imbedded latitude and longitude within the digital photograph, the digital photograph may consist of a photograph of the storage vessel and control device with a photograph of a separately operating GIS device within the same digital picture, provided the latitude and longitude output of the GIS unit can be clearly read in the digital photograph.

(6) Records of each closed vent system inspection required under § 60.5416a(a)(1) and (a)(2) for centrifugal compressors, reciprocating compressors and pneumatic pumps, or § 60.5416a(c)(1) for storage vessels.

(7) A record of each cover inspection required under § 60.5416a(a)(3) for centrifugal or reciprocating compressors or § 60.5416a(c)(2) for storage vessels.

(8) If you are subject to the bypass requirements of § 60.5416a(a)(4) for centrifugal compressors, reciprocating compressors or pneumatic pumps, or § 60.5416a(c)(3) for storage vessels, a record of each inspection or a record of each time the key is checked out or a record of each time the alarm is sounded.

(9) If you are subject to the closed vent system no detectable emissions requirements of § 60.5416a(b) for centrifugal compressors, reciprocating compressors or pneumatic pumps, a record of the monitoring conducted in accordance with § 60.5416a(b).

(10) For each centrifugal compressor or pneumatic pump affected facility, records of the schedule for carbon replacement (as determined by the design analysis requirements of § 60.5413a(c)(2) or (3)) and records of each carbon replacement as specified in § 60.5412a(c)(1).

(11) For each centrifugal compressor or pneumatic pump affected facility subject to the control device requirements of § 60.5412a(a), (b), and (c), records of minimum and maximum operating parameter values, continuous parameter monitoring system data, calculated averages of continuous parameter monitoring system data, results of all compliance calculations, and results of all inspections.

(12) For each carbon adsorber installed on storage vessel affected

facilities, records of the schedule for carbon replacement (as determined by the design analysis requirements of § 60.5412a(d)(2)) and records of each carbon replacement as specified in § 60.5412a(c)(1).

(13) For each storage vessel affected facility subject to the control device requirements of § 60.5412a(c) and (d), you must maintain records of the inspections, including any corrective actions taken, the manufacturers' operating instructions, procedures and maintenance schedule as specified in § 60.5417a(h)(3). You must maintain records of EPA Method 22 of appendix A–7 of this part, section 11 results, which include: Company, location, company representative (name of the person performing the observation), sky conditions, process unit (type of control device), clock start time, observation period duration (in minutes and seconds), accumulated emission time (in minutes and seconds), and clock end time. You may create your own form including the above information or use Figure 22–1 in EPA Method 22 of appendix A–7 of this part. Manufacturer's operating instructions, procedures and maintenance schedule must be available for inspection.

(14) A log of records as specified in §§ 60.5412a(d)(1)(iii), for all inspection, repair and maintenance activities for each control device failing the visible emissions test.

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

(i) The fugitive emissions monitoring plan for each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a compressor station as required in § 60.5397a(a).

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

(A) Date of the survey.

(B) Beginning and end time of the survey.

(C) Name of operator(s) performing survey. You must note the training and experience of the operator.

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

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

(F) Documentation of each fugitive emission, including the information specified in paragraphs (c)(15)(ii)(F)(*1*) through (*2*) of this section.

(*1*) Location.

(*2*) One or more digital photographs of each required monitoring survey being performed. The digital photograph must include the date the photograph was taken and the latitude and longitude of the collection of fugitive emissions components at a well site or collection of fugitive emissions components at a compressor station imbedded within or stored with the digital file. As an alternative to imbedded latitude and longitude within the digital photograph, the digital photograph may consist of a photograph of the monitoring survey being performed with a photograph of a separately operating GIS device within the same digital picture, provided the latitude and longitude output of the GIS unit can be clearly read in the digital photograph.

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

(4) Instrumentation used to resurvey a repaired fugitive emissions component that could not be repaired during the initial fugitive emissions finding.

(16) For each pneumatic pump affected facility, you must maintain the records identified in paragraphs (c)(16)(i) through (iv) of this section.

(i) Records of the date, location and manufacturer specifications for each pneumatic pump constructed, modified or reconstructed.

(ii) Records of deviations in cases where the pneumatic pump was not operated in compliance with the requirements specified in § 60.5393a.

(iii) Records of the control device installation date and the location of sites containing pneumatic pumps at which a control device was installed, where previously there was no control device at the site.

(iv) Except as specified in paragraph (c)(16)(iv)(G) of this section, records for each control device tested under § 60.5413a(d) which meets the criteria in § 60.5413a(d)(11) and § 60.5413a(e) and used to comply with § 60.5393a(b)(1) for each pneumatic pump.

(A) Make, model and serial number of purchased device.

(B) Date of purchase.

(C) Copy of purchase order.

(D) Location of the pneumatic pump and control device in latitude and longitude coordinates in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

(E) Inlet gas flow rate.

(F) Records of continuous compliance requirements in § 60.5413a(e) as specified in paragraphs (c)(16)(iv)(F)(*1*) through (*4*) of this section.

(*1*) Records that the pilot flame is present at all times of operation.

(*2*) Records that the device was operated with no visible emissions except for periods not to exceed a total of 2 minutes during any hour.

(*3*) Records of the maintenance and repair log.

(*4*) Records of the visible emissions test following return to operation from a maintenance or repair activity.

(G) As an alternative to the requirements of paragraph (c)(16)(iv)(D) of this part, you may maintain records of one or more digital photographs with the date the photograph was taken and the latitude and longitude of the pneumatic pump and control device imbedded within or stored with the digital file. As an alternative to imbedded latitude and longitude within the digital photograph, the digital photograph may consist of a photograph of the pneumatic pump and control device with a photograph of a separately operating GIS device within the same digital picture, provided the latitude and longitude output of the GIS unit can be clearly read in the digital photograph.

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

(a) You must comply with the requirements of paragraph (b) of this section in addition to the requirements of § 60.486a.

(b) The following recordkeeping requirements apply to pressure relief devices subject to the requirements of § 60.5401a(b)(1) of this subpart.

(1) When each leak is detected as specified in § 60.5401a(b)(2), a weatherproof and readily visible identification, marked with the equipment identification number, must be attached to the leaking equipment. The identification on the pressure relief device may be removed after it has been repaired.

(2) When each leak is detected as specified in § 60.5401a(b)(2), the information specified in paragraphs (b)(2)(i) through (x) of this section must be recorded in a log and shall be kept for 2 years in a readily accessible location:

(i) The instrument and operator identification numbers and the equipment identification number.

(ii) The date the leak was detected and the dates of each attempt to repair the leak.

(iii) Repair methods applied in each attempt to repair the leak.

(iv) ''Above 500 ppm'' if the maximum instrument reading measured by the methods specified in § 60.5400a(d) after each repair attempt is 500 ppm or greater.

(v) ''Repair delayed'' and the reason for the delay if a leak is not repaired within 15 calendar days after discovery of the leak.

(vi) The signature of the owner or operator (or designate) whose decision it was that repair could not be effected without a process shutdown.

(vii) The expected date of successful repair of the leak if a leak is not repaired within 15 days.

(viii) Dates of process unit shutdowns that occur while the equipment is unrepaired.

(ix) The date of successful repair of the leak.

(x) A list of identification numbers for equipment that are designated for no detectable emissions under the provisions of § 60.482–4a(a). The designation of equipment subject to the provisions of § 60.482–4a(a) must be signed by the owner or operator.

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

(a) You must comply with the requirements of paragraphs (b) and (c) of this section in addition to the requirements of § 60.487a(a), (b), (c)(2)(i) through (iv), and (c)(2)(vii) through (viii). You must submit semiannual reports to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI). (CEDRI can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*).) Use the appropriate electronic report in CEDRI for this subpart or an alternate electronic file format consistent with the extensible markup language (XML) schema listed on the CEDRI Web site (*http://www.epa.gov/ttn/chief/cedri/index.html*). If the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, submit the report to the Administrator at the appropriate address listed in § 60.4. You must begin submitting reports via CEDRI no later than 90 days after the form becomes available in CEDRI. The report must be submitted by the deadline specified in this subpart, regardless of the method in which the report is submitted.

(b) An owner or operator must include the following information in the initial semiannual report in addition to the information required in § 60.487a(b)(1) through (4): Number of pressure relief devices subject to the requirements of § 60.5401a(b) except for those pressure relief devices designated for no detectable emissions under the provisions of § 60.482–4a(a) and those pressure relief devices complying with § 60.482–4a(c).

(c) An owner or operator must include the information specified in paragraphs (c)(1) and (2) of this section in all semiannual reports in addition to the information required in § 60.487a(c)(2)(i) through (vi):

(1) Number of pressure relief devices for which leaks were detected as required in § 60.5401a(b)(2); and

(2) Number of pressure relief devices for which leaks were not repaired as required in § 60.5401a(b)(3).

§ 60.5423a What additional recordkeeping and reporting requirements apply to my sweetening unit affected facilities at onshore natural gas processing plants?

(a) You must retain records of the calculations and measurements required in § 60.5405a(a) and (b) and § 60.5407a(a) through (g) for at least 2 years following the date of the measurements. This requirement is included under § 60.7(f) of the General Provisions.

(b) You must submit a report of excess emissions to the Administrator in your annual report if you had excess emissions during the reporting period. The excess emissions report must be submitted to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI). (CEDRI can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*).) You must use the appropriate electronic report in CEDRI for this subpart or an alternate electronic file format consistent with the extensible markup language (XML) schema listed on the CEDRI Web site (*http://www.epa.gov/ttn/chief/cedri/index.html*). If the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, you must submit the report to the Administrator at the appropriate address listed in § 60.4. You must begin submitting reports via CEDRI no later than 90 days after the form becomes available in CEDRI. The report must be submitted by the deadline specified in this subpart, regardless of the method in which the report is submitted. For the purpose of these reports, excess emissions are defined as specified in paragraphs (b)(1) and (2) of this section.

(1) Any 24-hour period (at consistent intervals) during which the average sulfur emission reduction efficiency (R) is less than the minimum required efficiency (Z).

(2) For any affected facility electing to comply with the provisions of § 60.5407a(b)(2), any 24-hour period during which the average temperature of the gases leaving the combustion zone of an incinerator is less than the appropriate operating temperature as determined during the most recent performance test in accordance with the provisions of § 60.5407a(b)(3). Each 24-hour period must consist of at least 96 temperature measurements equally spaced over the 24 hours.

(c) To certify that a facility is exempt from the control requirements of these standards, for each facility with a design capacity less than 2 LT/D of H_2S in the acid gas (expressed as sulfur) you must keep, for the life of the facility, an analysis demonstrating that the facility's design capacity is less than 2 LT/D of H_2S expressed as sulfur.

(d) If you elect to comply with § 60.5407a(e) you must keep, for the life of the facility, a record demonstrating that the facility's design capacity is less than 150 LT/D of H_2S expressed as sulfur.

(e) The requirements of paragraph (b) of this section remain in force until and unless the EPA, in delegating enforcement authority to a state under section 111(c) of the Act, approves reporting requirements or an alternative means of compliance surveillance adopted by such state. In that event, affected sources within the state will be relieved of obligation to comply with paragraph (b) of this section, provided that they comply with the requirements established by the state. Electronic reporting to the EPA cannot be waived, and as such, the provisions of this paragraph do not relieve owners or operators of affected facilities of the requirement to submit the electronic reports required in this section to the EPA.

§ 60.5425a What parts of the General Provisions apply to me?

Table 3 to this subpart shows which parts of the General Provisions in §§ 60.1 through 60.19 apply to you.

§ 60.5430a What definitions apply to this subpart?

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act, in subpart A or subpart VVa of part 60; and the following terms shall have the specific meanings given them.

Acid gas means a gas stream of hydrogen sulfide (H_2S) and carbon dioxide (CO_2) that has been separated from sour natural gas by a sweetening unit.

Alaskan North Slope means the approximately 69,000 square-mile area extending from the Brooks Range to the Arctic Ocean.

API Gravity means the weight per unit volume of hydrocarbon liquids as measured by a system recommended by the American Petroleum Institute (API) and is expressed in degrees.

Bleed rate means the rate in standard cubic feet per hour at which natural gas is continuously vented (bleeds) from a pneumatic controller.

Capital expenditure means, in addition to the definition in 40 CFR 60.2, an expenditure for a physical or operational change to an existing facility that exceeds P, the product of the facility's replacement cost, R, and an adjusted annual asset guideline repair allowance, A, as reflected by the following equation: $P = R \times A$, where:

(1) The adjusted annual asset guideline repair allowance, A, is the product of the percent of the replacement cost, Y, and the applicable basic annual asset guideline repair allowance, B, divided by 100 as reflected by the following equation:

$A = Y \times (B \div 100)$;

(2) The percent Y is determined from the following equation: $Y = 1.0 - 0.575 \log X$, where X is 2011 minus the year of construction; and

(3) The applicable basic annual asset guideline repair allowance, B, is 4.5.

Centrifugal compressor means any machine for raising the pressure of a natural gas by drawing in low pressure natural gas and discharging significantly higher pressure natural gas by means of mechanical rotating vanes or impellers. Screw, sliding vane, and liquid ring compressors are not centrifugal compressors for the purposes of this subpart.

Certifying official means one of the following:

(1) For a corporation: A president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit and either:

(i) The facilities employ more than 250 persons or have gross annual sales or expenditures exceeding $25 million (in second quarter 1980 dollars); or

(ii) The Administrator is notified of such delegation of authority prior to the exercise of that authority. The Administrator reserves the right to evaluate such delegation;

(2) For a partnership (including but not limited to general partnerships, limited partnerships, and limited liability partnerships) or sole proprietorship: A general partner or the proprietor, respectively. If a general partner is a corporation, the provisions of paragraph (1) of this definition apply;

(3) For a municipality, State, Federal, or other public agency: Either a principal executive officer or ranking elected official. For the purposes of this part, a principal executive officer of a Federal agency includes the chief executive officer having responsibility for the overall operations of a principal geographic unit of the agency (*e.g.,* a Regional Administrator of EPA); or

(4) For affected facilities:

(i) The designated representative in so far as actions, standards, requirements, or prohibitions under title IV of the Clean Air Act or the regulations promulgated thereunder are concerned; or

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

Chemical/methanol or diaphragm pump means a gas-driven positive displacement pump typically used to inject precise amounts of chemicals into process streams or circulate glycol compounds for freeze protection.

City gate means the delivery point at which natural gas is transferred from a transmission pipeline to the local gas utility.

Collection system means any infrastructure that conveys gas or liquids from the well site to another location for treatment, storage, processing, recycling, disposal or other handling.

Completion combustion device means any ignition device, installed horizontally or vertically, used in exploration and production operations to combust otherwise vented emissions from completions.

Compressor station site means any permanent combination of one or more compressors that move natural gas at increased pressure through gathering or transmission pipelines, or into or out of storage. This includes, but is not limited to, gathering and boosting stations and transmission compressor stations.

Condensate means hydrocarbon liquid separated from natural gas that condenses due to changes in the temperature, pressure, or both, and remains liquid at standard conditions.

Continuous bleed means a continuous flow of pneumatic supply natural gas to a pneumatic controller.

Crude oil and natural gas source category means:

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

(2) Natural gas production, processing, transmission, and storage, which include the well and extend to, but do not include, the city gate.

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

Dehydrator means a device in which an absorbent directly contacts a natural gas stream and absorbs water in a contact tower or absorption column (absorber).

Deviation means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(1) Fails to meet any requirement or obligation established by this subpart including, but not limited to, any emission limit, operating limit, or work practice standard;

(2) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit; or

(3) Fails to meet any emission limit, operating limit, or work practice standard in this subpart during startup, shutdown, or malfunction, regardless of whether or not such failure is permitted by this subpart.

Delineation well means a well drilled in order to determine the boundary of a field or producing reservoir.

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

Field gas means feedstock gas entering the natural gas processing plant.

Field gas gathering means the system used transport field gas from a field to the main pipeline in the area.

Flare means a thermal oxidation system using an open (without enclosure) flame. Completion combustion devices as defined in this section are not considered flares.

Flow line means a pipeline used to transport oil and/or gas to a processing facility, a mainline pipeline, re-injection, or routed to a process or other useful purpose.

Flowback means the process of allowing fluids and entrained solids to flow from a well following a treatment, either in preparation for a subsequent phase of treatment or in preparation for cleanup and returning the well to production. The term flowback also means the fluids and entrained solids that emerge from a well during the flowback process. The flowback period begins when material introduced into the well during the treatment returns to the surface following hydraulic fracturing or refracturing. The flowback period ends when either the well is shut in and permanently disconnected from the flowback equipment or at the startup of production. The flowback period includes the initial flowback stage and the separation flowback stage.

Fugitive emissions component means any component that has the potential to emit fugitive emissions of methane or VOC at a well site or compressor station site, including but not limited to valves, connectors, pressure relief devices, open-ended lines, access doors, flanges, closed vent systems, thief hatches or other openings on a storage vessels, agitator seals, distance pieces, crankcase vents, blowdown vents, pump seals or diaphragms, compressors, separators, pressure vessels, dehydrators, heaters, instruments, and meters. Devices that vent as part of normal operations, such as natural gas-driven pneumatic controllers or natural gas-driven pumps, are not fugitive emissions components, insofar as the natural gas discharged from the device's vent is not considered a fugitive emission. Emissions originating from other than the vent, such as the seals around the bellows of a diaphragm pump, would be considered fugitive emissions.

Gas processing plant process unit means equipment assembled for the extraction of natural gas liquids from field gas, the fractionation of the liquids into natural gas products, or other operations associated with the processing of natural gas products. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the products.

Hydraulic fracturing means the process of directing pressurized fluids containing any combination of water, proppant, and any added chemicals to penetrate tight formations, such as shale or coal formations, that subsequently require high rate, extended flowback to expel fracture fluids and solids during completions.

Hydraulic refracturing means conducting a subsequent hydraulic fracturing operation at a well that has previously undergone a hydraulic fracturing operation.

In light liquid service means that the piece of equipment contains a liquid that meets the conditions specified in § 60.485a(e) or § 60.5401a(f)(2) of this part.

In wet gas service means that a compressor or piece of equipment contains or contacts the field gas before the extraction step at a gas processing plant process unit.

Initial flowback stage means the period during a well completion operation which begins at the onset of flowback and ends at the separation flowback stage.

Intermediate hydrocarbon liquid means any naturally occurring, unrefined petroleum liquid.

Intermittent/snap-action pneumatic controller means a pneumatic controller that is designed to vent non-continuously.

Liquefied natural gas unit means a unit used to cool natural gas to the point at which it is condensed into a liquid which is colorless, odorless, non-corrosive and non-toxic.

Low pressure well means a well with reservoir pressure and vertical well depth such that 0.445 times the reservoir pressure (in psia) minus 0.038 times the vertical well depth (in feet) minus 67.578 psia is less than the flow line pressure at the sales meter.

Maximum average daily throughput means the earliest calculation of daily average throughput during the 30-day PTE evaluation period employing generally accepted methods.

Natural gas-driven pneumatic controller means a pneumatic controller powered by pressurized natural gas.

Natural gas-driven chemical/methanol or diaphragm pump means a chemical or methanol injection or circulation pump or a diaphragm pump powered by pressurized natural gas.

Natural gas liquids means the hydrocarbons, such as ethane, propane, butane, and pentane that are extracted from field gas.

Natural gas processing plant (gas plant) means any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both. A Joule-Thompson valve, a dew point depression valve, or an isolated or standalone Joule-Thompson skid is not a natural gas processing plant.

Natural gas transmission means the pipelines used for the long distance transport of natural gas (excluding processing). Specific equipment used in natural gas transmission includes the land, mains, valves, meters, boosters, regulators, storage vessels, dehydrators, compressors, and their driving units and appurtenances, and equipment used for transporting gas from a production plant, delivery point of purchased gas, gathering system, storage area, or other wholesale source of gas to one or more distribution area(s).

Nonfractionating plant means any gas plant that does not fractionate mixed natural gas liquids into natural gas products.

Non-natural gas-driven pneumatic controller means an instrument that is actuated using other sources of power than pressurized natural gas; examples include solar, electric, and instrument air.

Onshore means all facilities except those that are located in the territorial seas or on the outer continental shelf.

Pneumatic controller means an automated instrument used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature.

Pressure vessel means a storage vessel that is used to store liquids or gases and is designed not to vent to the atmosphere as a result of compression of the vapor headspace in the pressure vessel during filling of the pressure vessel to its design capacity.

Process unit means components assembled for the extraction of natural gas liquids from field gas, the fractionation of the liquids into natural gas products, or other operations associated with the processing of natural gas products. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the products.

Produced water means water that is extracted from the earth from an oil or natural gas production well, or that is separated from crude oil, condensate, or natural gas after extraction.

Reciprocating compressor means a piece of equipment that increases the pressure of a process gas by positive displacement, employing linear movement of the driveshaft.

Reciprocating compressor rod packing means a series of flexible rings in machined metal cups that fit around the reciprocating compressor piston rod to create a seal limiting the amount of compressed natural gas that escapes to the atmosphere.

Recovered gas means gas recovered through the separation process during flowback.

Recovered liquids means any crude oil, condensate or produced water recovered through the separation process during flowback.

Reduced emissions completion means a well completion following fracturing or refracturing where gas flowback that is otherwise vented is captured, cleaned, and routed to the flow line or collection system, re-injected into the well or another well, used as an on-site fuel source, or used for other useful purpose that a purchased fuel or raw material would serve, with no direct release to the atmosphere.

Reduced sulfur compounds means H_2S, carbonyl sulfide (COS), and carbon disulfide (CS_2).

Removed from service means that a storage vessel affected facility has been physically isolated and disconnected from the process for a purpose other than maintenance in accordance with § 60.5395a(c)(1).

Responsible official means one of the following:

(1) For a corporation: A president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit and either:

(i) The facilities employ more than 250 persons or have gross annual sales or expenditures exceeding $25 million (in second quarter 1980 dollars); or

(ii) The delegation of authority to such representatives is approved in advance by the permitting authority;

(2) For a partnership or sole proprietorship: A general partner or the proprietor, respectively;

(3) For a municipality, State, Federal, or other public agency: Either a principal executive officer or ranking elected official. For the purposes of this part, a principal executive officer of a Federal agency includes the chief executive officer having responsibility for the overall operations of a principal geographic unit of the agency (*e.g.,* a Regional Administrator of EPA); or

(4) For affected facilities:

(i) The designated representative in so far as actions, standards, requirements, or prohibitions under title IV of the Clean Air Act or the regulations promulgated thereunder are concerned; or

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

Returned to service means that a storage vessel affected facility that was removed from service has been:

(1) Reconnected to the original source of liquids or has been used to replace any storage vessel affected facility; or

(2) Installed in any location covered by this subpart and introduced with crude oil, condensate, intermediate hydrocarbon liquids or produced water.

Routed to a process or route to a process means the emissions are conveyed via a closed vent system to any enclosed portion of a process where the emissions are predominantly recycled and/or consumed in the same manner as a material that fulfills the same function in the process and/or transformed by chemical reaction into materials that are not regulated materials and/or incorporated into a product; and/or recovered.

Salable quality gas means natural gas that meets the flow line or collection system operator specifications, regardless of whether such gas is sold.

Separation flowback stage means the period during a well completion operation when it is technically feasible for a separator to function. The separation flowback stage ends either at the startup of production, or when the well is shut in and permanently disconnected from the flowback equipment.

Startup of production means the beginning of initial flow following the end of flowback when there is continuous recovery of salable quality gas and separation and recovery of any crude oil, condensate or produced water.

Storage vessel means a tank or other vessel that contains an accumulation of crude oil, condensate, intermediate hydrocarbon liquids, or produced water, and that is constructed primarily of nonearthen materials (such as wood, concrete, steel, fiberglass, or plastic) which provide structural support. A well completion vessel that receives recovered liquids from a well after startup of production following flowback for a period which exceeds 60 days is considered a storage vessel under this subpart. A tank or other vessel shall not be considered a storage vessel if it has been removed from service in accordance with the requirements of § 60.5395a(c) until such time as such tank or other vessel has been returned to service. For the purposes of this subpart, the following are not considered storage vessels:

(1) Vessels that are skid-mounted or permanently attached to something that is mobile (such as trucks, railcars, barges or ships), and are intended to be located at a site for less than 180 consecutive days. If you do not keep or are not able to produce records, as required by § 60.5420a(c)(5)(iv), showing that the vessel has been located at a site for less than 180 consecutive days, the vessel described herein is considered to be a storage vessel from the date the original vessel was first located at the site. This exclusion does not apply to a well completion vessel as described above.

(2) Process vessels such as surge control vessels, bottoms receivers or knockout vessels.

(3) Pressure vessels designed to operate in excess of 204.9 kilopascals and without emissions to the atmosphere.

Sulfur production rate means the rate of liquid sulfur accumulation from the sulfur recovery unit.

Sulfur recovery unit means a process device that recovers element sulfur from acid gas.

Surface site means any combination of one or more graded pad sites, gravel pad sites, foundations, platforms, or the immediate physical location upon which equipment is physically affixed.

Sweetening unit means a process device that removes hydrogen sulfide and/or carbon dioxide from the sour natural gas stream.

Total Reduced Sulfur (TRS) means the sum of the sulfur compounds hydrogen sulfide, methyl mercaptan, dimethyl sulfide, and dimethyl disulfide as measured by Method 16 of appendix A–6 of this part.

Total SO_2 equivalents means the sum of volumetric or mass concentrations of the sulfur compounds obtained by adding the quantity existing as SO_2 to the quantity of SO_2 that would be obtained if all reduced sulfur compounds were converted to SO_2 (ppmv or kg/dscm (lb/dscf)).

Underground storage vessel means a storage vessel stored below ground.

Well means a hole drilled for the purpose of producing oil or natural gas, or a well into which fluids are injected.

Well completion means the process that allows for the flowback of petroleum or natural gas from newly drilled wells to expel drilling and reservoir fluids and tests the reservoir flow characteristics, which may vent produced hydrocarbons to the atmosphere via an open pit or tank.

Well completion operation means any well completion with hydraulic fracturing or refracturing occurring at a well affected facility.

Well completion vessel means a vessel that contains flowback during a well completion operation following hydraulic fracturing or refracturing. A well completion vessel may be a lined earthen pit, a tank or other vessel that is skid-mounted or portable. A well completion vessel that receives recovered liquids from a well after startup of production following flowback for a period which exceeds 60 days is considered a storage vessel under this subpart.

Well site means one or more areas that are directly disturbed during the drilling and subsequent operation of, or affected by, production facilities directly associated with any oil well, natural gas well, or injection well and its associated well pad. For the purposes of the fugitive emissions standards at § 60.5397a, well site also includes tank batteries collecting crude oil, condensate, intermediate hydrocarbon liquids, or produced water from wells not located at the well site (e.g., centralized tank batteries).

Wellhead means the piping, casing, tubing and connected valves protruding above the earth's surface for an oil and/or natural gas well. The wellhead ends where the flow line connects to a wellhead valve. The wellhead does not include other equipment at the well site except for any conveyance through which gas is vented to the atmosphere.

Wildcat well means a well outside known fields or the first well drilled in an oil or gas field where no other oil and gas production exists.

§§ 60.5431a–60.5499a [Reserved]

TABLE 1 TO SUBPART OOOOa OF PART 60—REQUIRED MINIMUM INITIAL SO_2 EMISSION REDUCTION EFFICIENCY (Z_i)

H_2S content of acid gas (Y), %	Sulfur feed rate (X), LT/D			
	2.0<X<5.0	5.0<X<15.0	15.0<X<300.0	X>300.0
Y>50	79.0	88.51$X^{0.0101}Y^{0.0125}$ or 99.9, whichever is smaller.		
20<Y<50	79.0	88.51$X^{0.0101}Y^{0.0125}$ or 97.9, whichever is smaller.		97.9
10<Y<20	79.0	88.51$X^{0.0101}Y^{0.0125}$ or 93.5, whichever is smaller.	93.5	93.5
Y<10	79.0	79.0	79.0	79.0

TABLE 2—TO SUBPART OOOOa OF PART 60—REQUIRED MINIMUM SO_2 EMISSION REDUCTION EFFICIENCY (Z_c)

H_2S content of acid gas (Y), %	Sulfur feed rate (X), LT/D			
	2.0<X<5.0	5.0<X<15.0	15.0<X<300.0	X>300.0
Y>50	74.0	85.35$X^{0.0144}Y^{0.0128}$ or 99.9, whichever is smaller.		
20<Y<50	74.0	85.35$X^{0.0144}Y^{0.0128}$ or 97.5, whichever is smaller.		97.5
10<Y<20	74.0	85.35$X^{0.0144}Y^{0.0128}$ or 90.8, whichever is smaller.	90.8	90.8
Y<10	74.0	74.0	74.0	74.0

X = The sulfur feed rate from the sweetening unit (*i.e.*, the H_2S in the acid gas), expressed as sulfur, Mg/D(LT/D), rounded to one decimal place.

Y = The sulfur content of the acid gas from the sweetening unit, expressed as mole percent H_2S (dry basis) rounded to one decimal place.

Z = The minimum required sulfur dioxide (SO_2) emission reduction efficiency, expressed as percent carried to one decimal place. Zi refers to the reduction efficiency required at the initial performance test. Zc refers to the reduction efficiency required on a continuous basis after compliance with Zi has been demonstrated.

TABLE 3 TO SUBPART OOOOa OF PART 60—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART OOOOa

[As stated in § 60.5425a, you must comply with the following applicable General Provisions]

General provisions citation	Subject of citation	Applies to subpart?	Explanation
§ 60.1	General applicability of the General Provisions	Yes	
§ 60.2	Definitions	Yes	Additional terms defined in § 60.5430a.
§ 60.3	Units and abbreviations	Yes	
§ 60.4	Address	Yes	
§ 60.5	Determination of construction or modification	Yes	
§ 60.6	Review of plans	Yes	
§ 60.7	Notification and record keeping	Yes	Except that § 60.7 only applies as specified in § 60.5420a(a).
§ 60.8	Performance tests	Yes	Performance testing is required for control devices used on storage vessels, centrifugal compressors and pneumatic pumps.
§ 60.9	Availability of information	Yes	
§ 60.10	State authority	Yes	
§ 60.11	Compliance with standards and maintenance requirements.	No	Requirements are specified in subpart OOOOa.
§ 60.12	Circumvention	Yes	
§ 60.13	Monitoring requirements	Yes	Continuous monitors are required for storage vessels.

TABLE 3 TO SUBPART OOOOa OF PART 60—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART OOOOa—Continued

[As stated in § 60.5425a, you must comply with the following applicable General Provisions]

General provisions citation	Subject of citation	Applies to subpart?	Explanation
§ 60.14	Modification	Yes	To the extent any provision in § 60.14 conflicts with specific provisions in subpart OOOOa, it is superseded by subpart OOOOa provisions.
§ 60.15	Reconstruction	Yes	Except that § 60.15(d) does not apply to pneumatic controllers, pneumatic pumps, centrifugal compressors or storage vessels.
§ 60.16	Priority list	Yes	
§ 60.17	Incorporations by reference	Yes	
§ 60.18	General control device and work practice requirements.	Yes	
§ 60.19	General notification and reporting requirement	Yes	

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